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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

September 26, 2012

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

Re: General Natural Gas Rate Application
Docket No. D2012.9.___

Dear Ms. Whitney:

Montana-Dakota Utilities Co. (Montana-Dakota, Company or Applicant), a Division of MDU Resources Group, Inc., herewith submits its application for approval to increase its rates for natural gas service pursuant to the Montana Code Annotated, Title 69, Chapter 3, regarding regulation of utilities; Title 2, Chapter 4, regarding administrative proceedings; and this Commission's rules regarding the filing of utility rate change applications (Administrative Rules of Montana (ARM) §38.5.101, et seq.). Montana-Dakota also submits its Application for an Interim Increase in accordance with the requirements set forth in ARM §38.5.501 through §38.5.506.

Montana-Dakota will prove by competent evidence that its existing natural gas rates do not allow Montana-Dakota to fully recover the cost of providing gas service to its Montana customers and that therefore, the current rates are unjust, unreasonable and not compensatory.

The primary reason for the increase in rates is the increased investment in facilities and the associated depreciation, operation and maintenance expenses and taxes associated with the increase in investment. The gross investment in Montana gas operations has increased by over $36 million, or approximately 57 percent, since the last rate case in 2004 to the pro forma levels included in this case. In addition to the ongoing investment for new customers and replacing existing facilities, investments in a landfill gas production facility, a new region operations building, and an automated meter reading system have occurred since the last case, along with a new customer billing system to be completed in 2012.

Montana-Dakota strives to control its costs by continually looking for opportunities that create efficiencies and control costs. Operation and maintenance expenses have decreased on a per customer basis, from an annual cost per customer of $170 per customer in 2004 to an annual pro forma cost of $141 per customer. During this same time period the Consumer Price Index (CPI) increased by 19 percent.

Authorization of the requested increase in revenues will provide Montana-Dakota a reasonable opportunity to earn a fair rate of return for its Montana natural gas operations. In addition, Montana-Dakota is requesting approval of a weather normalization adjustment mechanism to stabilize the recovery of fixed distribution costs in the heating season.

The Company proposes a total increase in distribution revenues of $3,457,412 as shown on Statement H, page 7 based on an average test year for the twelve months ended December 31, 2011 adjusted for known and measurable changes. The proposed increase will affect approximately 78,910 natural gas customers in Montana. The proposed change in rates will affect customer classes by the following amounts and percentages:

Class	Amount	Percent Increase
Residential	$2,836,325	7.9%
Firm General	594,426	2.8%
Small Interruptible	19,161	1.4%
Large Interruptible	7,500	1.4%
Total	$3,457,412	5.9%

Montana-Dakota also requests interim rate relief as set forth in its Application for Interim Increase in Natural Gas Rates in the amount of $1,686,422 to take effect within 30 days. The interim rate increase was calculated in accordance with ARM §38.5.506.

Pursuant to ARM §38.5.503, the attached Notice has been served (as a part of this filing) to this Commission and the Montana Consumer Counsel and also mailed to all parties on the Certificate of Service, which includes interested parties that participated in the last general rate case (Docket No. D2004.4.50). A copy of the press release issued by the Company regarding the filing has also been distributed to the media in the area affected by the increase in rates.

In support of the Company's request, the following documents are included with this Letter of Transmittal:

- Notice and Certificate of Service

- The Application including:
  - Appendix A – Current Rate Schedules
  - Appendix B - Proposed Final Rate Schedules including a redlined version of tariffs denoting proposed changes.

- The Application for Interim Increase in Natural Gas Rates including:
  - Proposed Interim Rate Schedules
  - Statements and Workpapers underlying the interim request

- Prefiled Direct Testimony and Exhibits in support of the Application

- Supporting Statements and Workpapers required by the Commission's filing requirements, ARM §38.5.103 through §38.5.180

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501
Rita.mulkern@mdu.com

Also, please send copies of all written inquiries, correspondence and pleadings to:

Mr. John Alke
Hughes, Kellner, Sullivan & Alke
40 West Lawrence, Suite A
Helena, Montana 59601
jalke@hksalaw.com

The original and ten (10) copies of this Letter of Transmittal, Application and Appendices, Application for Interim Increase in Natural Gas Rates, Testimony and Exhibits, and Statements have been filed with the Montana Public Service Commission.

Two (2) copies of same have this day been mailed to the Montana Consumer Counsel, P.O. Box 201703, Helena, Montana 59620-1703. All of the materials included in this Application will be available for public inspection at each of Montana-Dakota's business offices.

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

Sincerely,

David L. Goodin
President and Chief Executive Officer

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Natural Gas Service	)))))	Docket No. D2012.9.__

Notice

An Application to increase natural gas rates was filed with the Montana Public Service Commission on September 26, 2012 by Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Such Application proposes a revenue increase of $3,457,212, representing an overall percentage increase of 5.9 percent.

Montana-Dakota has also requested that an interim increase of $1,686,422 be effective within 30 days of the filing date.

Pursuant to Administrative Rules of Montana §38.5.503, all parties listed on the attached Certificate of Service have been mailed this Notice. Parties desiring a complete copy of the said Application will be promptly provided a copy upon receipt of a written request directed to:

Rita A. Mulkern – Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501
rita.mulkern@mdu.com

Dated this 26th day of September, 2012.

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

CERTIFICATE OF SERVICE

* * * * *

I hereby certify that on the 26th day of September 2012, I served copies of Montana-Dakota Utilities Co.'s Notice on all parties listed on the attached Service List. This Notice advised that Montana-Dakota has requested increased rates for its natural gas service operations.

Sara J. Graf
Regulatory Compliance Specialist
Montana-Dakota Utilities Co.
Bismarck, North Dakota 58501

Subscribed and sworn to before me this 26th day of September, 2012.

LAURIE LARSON
Notary Public
State of North Dakota
My Commission Expires May 17, 2018

Laurie Larson, Notary Public
Burleigh County, North Dakota
My Commission Expires: 05/17/2018

Montana-Dakota Utilities Co.
Docket No. D2012.9.___
Service List

Ms. Kate Whitney, Administrator (11)
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620
kwhitney@mt.gov

Robert Nelson (2)
Montana Consumer Counsel
111 North Last Chance Gulch
Suite 1B
Helena, MT 59601
robnelson@mt.gov

John Alke
40 West Lawrence, Suite A
PO Box 1166
Helena, MT 59624-1166
johnalke@hksalaw.com

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Natural Gas Service	)))))	Docket No. D2012.9.__

* * * *

APPLICATION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant in the above-entitled proceeding (hereafter "Montana-Dakota" or "Applicant"), and respectfully alleges as follows:

I.

That Montana-Dakota, a Division of MDU Resources Group, Inc., is a Delaware corporation duly authorized to do business in the State of Montana as a foreign corporation, and that it is doing business in the State of Montana as a public utility.

II.

That the Certificate of Incorporation and Amendments thereto have previously been filed with the Montana Public Service Commission (PSC or Commission) and reference thereto is hereby made, and such Certificate and Amendments are hereby incorporated herein by reference as though fully set forth herein.

III.

That Applicant's full name and post office address are:

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

That the following described rate schedules presently on file with and approved by the Commission are attached hereto as Appendix A.

Volume No. 6	Description
2nd Revised Sheet No. 1	Table of Contents
1st Revised Sheet No. 2	Communities Served
97th Revised Sheet No. 3	Rate Summary Sheet
7th Revised Sheet No. 4	Thermal Zone Boundaries
9th Revised Sheet No. 11	Residential Gas Service Rate 60
4th Revised Sheet No. 11.1	Residential Gas Service Rate 60
9th Revised Sheet No. 21	Firm General Gas Service Rate 70
2nd Revised Sheet No. 21.1	Firm General Gas Service Rate 70
2nd Revised Sheet No. 22	Small Interruptible General Gas Service Rate 71
1st Revised Sheet Nos. 22.1 –22.4	Small Interruptible General Gas Service Rate 71
10th Revised Sheet No. 23	Optional Seasonal General Gas Service Rate 72
2nd Revised Sheet No. 23.1	Optional Seasonal General Gas Service Rate 72
2nd Revised Sheet No. 31	Electric Generation Interruptible Transportation Service Rate 80
1st Revised Sheet No. 31.1	Electric Generation Interruptible Transportation Service Rate 80
1st Revised Sheet No. 32	Transportation Service Rates 81 and 82
2nd Revised Sheet No. 32.1	Transportation Service Rates 81 and 82
1st Revised Sheet Nos. 32.2 – 32.11	Transportation Service Rates 81 and 82
1st Revised Sheet Nos. 34 – 34.4	Large Interruptible General Gas Service Rate 85
3rd Revised Sheet No. 37	Gas Cost Tracking Adjustment Procedure Rate 88

2nd Revised Sheet No. 37.1	Gas Cost Tracking Adjustment Procedure Rate 88
1st Revised Sheet No. 37.2	Gas Cost Tracking Adjustment Procedure Rate 88
2nd Revised Sheet No. 37.3	Gas Cost Tracking Adjustment Procedure Rate 88
1st Revised Sheet Nos. 37.4 – 37.5	Gas Cost Tracking Adjustment Procedure Rate 88
2nd Revised Sheet No. 38	Universal System Benefits Charge Rate 89
2nd Revised Sheet No. 39	Conservation Program Tracking Mechanism Rate 90
1st Revised Sheet No. 42	Special Gas Service Rate 93
1st Revised Sheet Nos. 49 – 49.1	Table of Contents Conditions of Service Rate 100
1st Revised Sheet Nos. 49.2 – 49.16	Conditions of Service Rate 100
2nd Revised Sheet No. 49.17	Conditions of Service Rate 100
1st Revised Sheet Nos. 49.18 – 49.22	Conditions of Service Rate 100
Original Sheet No. 49.23	Conditions of Service Rate 100
1st Revised Sheet Nos. 68 – 68.2	Interruptible Gas Service Extension Policy Rate 119
1st Revised Sheet Nos. 69 – 69.7	Firm Gas Service Extension Policy Rate 120
1st Revised Sheet Nos. 74 – 74.1	New Installation, Replacement, Relocation and Repair of Gas Service Lines Rate 124

V.

That Applicant respectfully submits herewith the following described proposed rate schedules for natural gas service, copies attached hereto as Appendix B, which Applicant proposes to be approved on a final basis in this Docket. The Rate Summary Sheet (Sheet No. 3) will be submitted upon final disposition of the Company's request in this Docket.

Volume No. 6	Description
3rd Revised Sheet No. 1	Table of Contents
11th Revised Sheet No. 11	Residential Gas Service Rate 60
5th Revised Sheet No. 11.1	Residential Gas Service Rate 60
11th Revised Sheet No. 21	Firm General Gas Service Rate 70
3rd Revised Sheet No. 21.1	Firm General Gas Service Rate 70
3rd Revised Sheet No. 22	Small Interruptible General Gas Service Rate 71
12th Revised Sheet No. 23	Optional Seasonal General Gas Service Rate 72
3rd Revised Sheet No. 31	(Reserved for Future Use)

2nd Revised Sheet No. 31.1	(Reserved for Future Use)
3rd Revised Sheet No. 32.1	Transportation Service Rates 81 and 82
2nd Revised Sheet No. 34	Large Interruptible General Gas Service Rate 85
Original Sheet Nos. 36-36.1	Distribution Delivery Stabilization Mechanism Rate 87
2nd Revised Sheet No. 42	Special Gas Service Rate 93
2nd Revised Sheet No. 49.21	Conditions of Service Rate 100

VI.

That the existing rates of Applicant are unjust, unreasonable and not compensatory, and that said rates should be increased so that Applicant will have an opportunity to earn a just and reasonable rate of return on its natural gas property devoted to providing service to its Montana gas customers.

VII.

That in submitting this Application and in proposing the implementation of the increased rates contained herein, Applicant is seeking additional revenues of $3,457,412 based on a 2011 test period, adjusted for known and measurable changes, for gas service rendered to customers in the State of Montana. This request for additional revenues amounts to a 5.9 percent increase over current gas rates.

VIII.

That Applicant is entitled to interim rate relief in the amount of $1,686,422 as set forth in the enclosed Application for Interim Increase in Natural Gas Rates.

IX.

That Applicant will prove by competent evidence that existing rates are unjust, unreasonable, and not compensatory, and that said rate schedules should be increased as requested herein. Filed concurrently with this Application and its Appendices are supporting Statements and Direct Testimony and Exhibits of Applicant's witnesses. Such Statements, Testimony, and Exhibits are by this reference incorporated as if fully set forth herein.

X.

That this Application is submitted in accordance with the provisions of Title 69 of the Montana Code Annotated and the rules and regulations promulgated by the Public Service Commission of the State of Montana.

WHEREFORE, Applicant respectfully requests that the Public Service Commission of the State of Montana:

1. Grant interim rate relief to Applicant in the amount of $1.686,422 in accordance with Applicant's Application for Interim Increase in Natural Gas Rates, submitted herewith;
2. Approve and adopt the proposed rate changes as set forth in Appendix B of this Application that will produce an annual increase in revenues of $3,457,412 to be effective upon final disposition of this Docket;
3. Grant such other and additional relief as the Commission shall deem just and proper.

Dated this 26th day of September, 2012.

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

By: ______________________
David L. Goodin
President and Chief Executive Officer

STATE OF NORTH DAKOTA)
:ss
COUNTY OF BURLEIGH)

David L. Goodin, being first duly sworn, deposes and says that he is the President and Chief Executive Officer of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., the Applicant herein, that he has read the foregoing Application, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information and belief.

Dated this 26th day of September, 2012.

David L. Goodin
President and Chief Executive Officer

Subscribed and sworn to before me this 26th day of September, 2012.

SARA J GRAF
Notary Public
State of North Dakota
My Commission Expires September 18, 2013

Sara J. Graf, Notary Public
Burleigh County, North Dakota
My Commission Expires: 09/18/2013

OF COUNSEL:

John Alke
Hughes, Kellner, Sullivan & Alke
40 West Lawrence, Suite A
Helena, Montana 59601

Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Appendix A

TABLE OF CONTENTS

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

Volume No. 6
1st Revised Sheet No. 2
Canceling Original Sheet No. 2

COMMUNITIES SERVED

NATURAL GAS SERVICE

Rocky Mountain Region

Belfry	Fromberg	Pryor
Billings*	Hardin	Rockvale
Bridger	Joliet	Silesia
Crow Agency	Laurel	
Edgar	Park City	

Badlands Region

Baker	Ismay	Savage
Fairview	Malta	Sidney
Forsyth	Miles City	St. Marie
Fort Peck	Nashua	Terry
Frazer	Poplar	Whitewater
Glasgow	Richey	Wibaux
Glendive	Rosebud	Wolf Point
Hinsdale	Saco	

*Designates Region Office

Issued: April 22, 2003

By: Donald R. Ball
Assistance Vice President-
Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Docket No. D2002.5.59

Effective for bills rendered on or after
April 13, 2003

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	CTA	Cost of Gas	Total Rate/ Dk
Residential Rate 60	11	$6.35 per month	$1.126	$0.010	$4.284	$5.420
Firm General Service Rate 70	21					
Meters rated < 500 cubic feet		$10.40 per month				
Meters rated > 500 cubic feet		$22.05 per month	$1.353	$0.010	$4.284	$5.647
			(Maximum)			(Maximum)
Small Interruptible Gas Rate 71	22	$125.00 per month	$0.742		$3.406	$4.148
Optional Seasonal Gas						
Service Rate 72	23					
Meters rated < 500 cubic feet		$10.40 per month				
Meters rated > 500 cubic feet		$22.05 per month				
Winter Gas Usage			$1.353	$0.010	$4.396	$5.759
Summer Gas Usage			$1.353	$0.010	$3.359	$4.722
Electric Generation Interruptible						
Transportation Service Rate 80	31	$175.00 per month				
Maximum			$0.742			
Minimum			$0.101			
Transportation Service	32					
Small Interruptible Rate 81		$175.00 per month				
Maximum			$0.742			
Minimum			$0.101			
Fuel Charge					$0.024	
Large Interruptible Rate 82		$530.00 per month				
Maximum			$0.500			
Minimum			$0.050			
Fuel Charge					$0.024	
			(Maximum)			(Maximum)
Large Interruptible Gas Rate 85	34	$480.00 per month	$0.500		$3.406	$3.906

Issued: August 10, 2012

By: Tamie A. Aberle
Regulatory Affairs Manager

For Office Use Only - Do Not Print Below This Line

Docket No. D2011.9.77

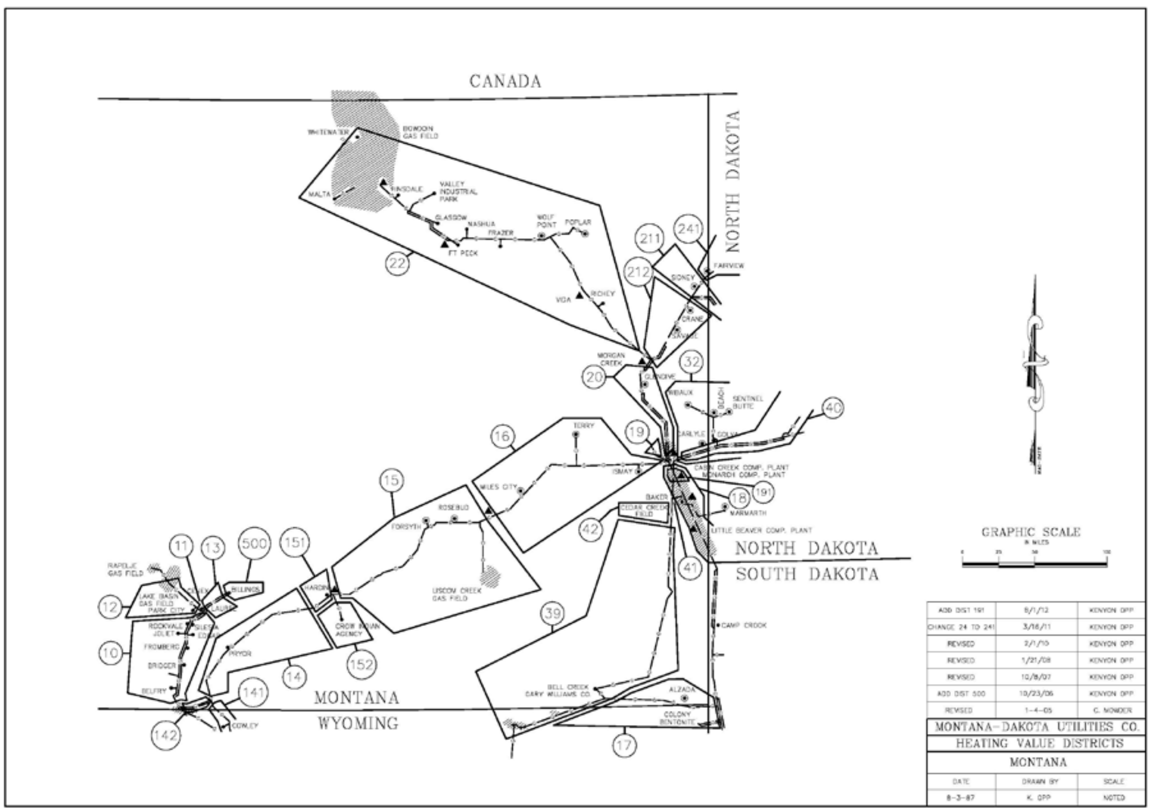
Service rendered on and after September 1, 2012

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

THERMAL ZONE BOUNDARIES



Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$6.35 per month
Distribution Delivery Charge:	$1.126 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

Low-Income Discount:

Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP assistance.

% Of Federal Poverty	Discount Rate
0-60%	30%
61%-90%	25%
91%-maximum allowed	20%

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$125.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$.742 per dk	$.101 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

General Terms and Conditions:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on firm gas service rates. Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or interrupt such service whenever, in the Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with Rate 100, §V.10.

2. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will

remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and telephone service at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly operate equipment. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the automatic shut-off equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

3. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70(distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

4. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder. If mutually agreed to by the Company and customer, the term of service reflected in such agreement may be amended. Upon expiration of service, customer may apply for and receive, at the sole discretion of the Company, gas service under another appropriate rate schedule for customer's operations.

5. OBLIGATION TO NOTIFY THE COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify the Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to customer equal to the penalty amounts the Company must pay to the interconnecting pipeline caused by customer's action.

6. METERING REQUIREMENTS:
   a. Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

   b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly transmit data. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the remote data acquisition equipment and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company's remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company's equipment.

7. RULES - The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

General Terms and Conditions:

1. Customer agrees to contract for service under the Optional Seasonal General Gas Service Rate 72 for a minimum of one year.

2. The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

ELECTRIC GENERATION INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80

Availability:

This service is available to the Miles City and Glendive combustion turbines and the Lewis & Clark steam generating unit for transportation of natural gas on an interruptible basis to these facilities for the sole purpose of electric generation.

Basic Service Charge: $175.00 per month

Transportation Charge:

Customer shall pay a calculated rate as specified herein, not more than the maximum nor less than the minimum set forth below.

Maximum	$.742 per dk
Minimum	$.101 per dk

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Calculation of Transportation Charge:

The transportation charge for gas used for generation sales to Mid-Continent Area Power Pool (MAPP) will be calculated as follows:

The price quoted to MAPP (excluding any MAPP loss factor) less the applicable pool adder for the particular MAPP schedule under which the sale is being made, less turbine start-up costs, less maintenance costs, less cost of fuel(s) and less pipeline transportation charges. In no event, shall the gas transportation charge hereunder be less than the minimum rate nor more than the maximum rate.

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ELECTRIC GENERATION INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80

The transportation charge for gas used for generation for Montana Dakota's native load will be calculated as follows:

> The price quoted by others for a MAPP sale to Montana-Dakota less turbine start-up costs, less maintenance costs, less cost of fuel(s) and less pipeline transportation charges. In no event, shall the gas transportation charge hereunder be less than the minimum rate nor more than the maximum rate.

Price Flexibility:

Transportation charges may be flexed by individual transaction on an hourly basis.

General Terms and Conditions:

1. The transportation service general terms and conditions under Rates 81 and 82 are all applicable to this rate.

2. Gas transported under this Rate 80 shall not be considered system supply gas as defined in Rate 88.

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through the Company's distribution facilities. In order to obtain transportation service, customer must qualify under an applicable gas transportation service rate; meet the general terms and conditions of service provided hereunder; and enter into a gas transportation agreement upon request of the Company.

The transportation services are as follows:

<u>Small Interruptible General Gas Transportation Service Rate 81:</u>
Transportation service is available for all general gas service customers whose interruptible natural gas load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point, whose average use of natural gas will not exceed 100,000 dk annually, and who, absent the request for transportation service, are eligible for natural gas service, on an interruptible basis, pursuant to the Company's effective Small Interruptible General Gas Service Rate 71. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

<u>Large Interruptible General Gas Transportation Service Rate 82:</u>
Transportation service is available for all general gas service customers whose interruptible natural gas requirements will exceed 100,000 dk annually metered at a single delivery point, and who, absent the request for transportation service, are eligible for natural gas service pursuant to the Company's effective Large Interruptible General Gas Service Rate 85. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70.

Rate:

Basic Service Charge

Rate 81	Rate 82
$175.00 per month	$530.00 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$0.742	$0.500
Minimum Rate per dk	$0.101	$0.050
Fuel Charge (Applicable to all dk transported)*	See Rate Summary Sheet	
Balancing Charge per dk	$0.300	$0.300

* Fuel charge does not apply to transmission level customers.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

General Terms and Conditions:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE- To qualify for gas transportation service, customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

3. MULTIPLE SERVICES THROUGH ONE METER:
   a. In the event customer desires firm sales service in addition to gas transportation service, customer shall request such firm volume requirements, and upon approval by the Company, such firm volume requirements shall be set forth in a firm service agreement. For billing purposes, the level of volumes so specified or the actual volume used, whichever is lower, shall be billed at Rate 70. Volumes delivered in excess of such firm volumes shall be billed at the applicable gas transportation rate. Customer has the option to install, at their expense, piping necessary for separate measurement of sales and transportation volumes.

   b. Customer shall pay, in addition to charges specified in the applicable gas transportation rate schedule, charges under all other applicable rate schedules for any service in addition to that provided herein (irrespective of whether customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE - The Company shall have the right to curtail or interrupt deliveries without being required to give previous notice of intention to curtail or interrupt, whenever, in its judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of Rate 100, §V.10.

5. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

   b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and telephone service at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly operate equipment. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the automatic shut-off equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

6. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken above that received on customer's behalf, shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

7. NON-DELIVERED VOLUMES/PENALTY:
   a. In the event customer uses more gas than is being delivered to the Company's interconnection with the delivering pipeline(s) (receipt point), customer shall pay an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same receipt point, any payment or overrun penalties the Company is required to make shall be allocated on a pro rata basis among such customers on the basis of each customer's use of gas in excess of available volumes.

b. In the event customer's gas is not being delivered to the receipt point for any reason and customer continues to take gas, customer shall be subject to any applicable penalties or charges set forth in Paragraph 7.a. Gas volumes supplied by Company will be charged at Firm General Gas Service Rate 70 (distributed delivery charge and cost of gas). The Company is under no obligation to notify customer of non-delivered volumes.

c. In the event customer's transportation volumes are not available for any reason, customer may take interruptible sales service if such service is available. The availability of interruptible sales service shall be determined at the sole discretion of the Company.

8. ELECTION OF SERVICE - Prior to the initiation of service hereunder, customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by the Company and customer, the term of service may be amended. Upon expiration of service, customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for customer's operations.

9. RECONNECTION FEE - Transportation customers who cease service and then resume service within the succeeding 12 months, shall be subject to a reconnection charge as specified in Rate 100, §V.19.

10. BALANCING:

a. To the extent practicable, customer and the Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.

If, at the end of a billing month, the accumulated difference between actual gas deliveries to customer and nominated (scheduled) receipts on behalf of such customer exceeds 4% of that month's scheduled receipts, resulting in a negative imbalance (i.e., deliveries exceed scheduled receipts), customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, customer shall then be billed, in addition to the applicable transportation rate, a penalty for the under nominated volume exceeding 4% at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas). The accumulated difference between the actual gas deliveries to customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume on which a penalty was imposed.

If, at the end of a billing month, the accumulated difference between nominated (scheduled) receipts on behalf of such customer and actual gas deliveries to customer exceeds 4% of that month's scheduled receipts resulting in a positive imbalance (i.e., scheduled receipts exceed deliveries), customer will be assessed a balancing charge, set forth herein, on the imbalance exceeding 4%. If such imbalance is not eliminated by the end of the next monthly billing period, (1) the Company may adjust the volume of gas received on behalf of customer so as to eliminate the prior period over nomination exceeding 4% up to 10% and (2) the Company shall retain the over nomination of gas exceeding 10% free and clear of any adverse claims relating thereto when such accumulated difference exceeds 50 dk. The accumulated difference between the actual gas deliveries to customer and nominated (scheduled) receipts on behalf of such customer will be adjusted for the volume retained.

b. In the event customer's imbalance causes the Company to incur a balancing penalty from its interconnecting pipeline(s), customer shall pay any penalty payments or overrun charges the Company is required to make under the terms of its contract(s) with interconnecting pipeline(s) resulting from such action by customer. In the event that more than one customer is obtaining gas from the same shipper and/or agent at the same interconnection with a delivering pipeline, any payment or overrun penalties the Company is required to make shall be apportioned among such customers on the basis of each customer's contribution toward the imbalance.

c. Customer's nominations made to clear imbalances will be subject to the priority of service and allocation of capacity provisions set forth in Rate 100, §V.10 and the penalties for failure to curtail or interrupt use of gas set forth in Paragraph 6 of this rate schedule.

d. Termination of the gas transportation service shall not relieve the Company and customer of the obligation to correct any quantity imbalances hereunder or customer of the obligation to pay money due hereunder to the Company.

e. The Company may waive any penalty associated with Company adjustments to end-use customer nominations in those instances where the Company, due to operating limitations, is required to adjust end-use transportation customer nominations and such Company adjustments create a penalty situation or preclude customer from correcting an imbalance which results in a penalty.

11. NOMINATION VARIANCE CHARGE - Customer shall pay, any payments the Company must make to its interconnecting pipeline(s), as a result of nomination variance penalties caused by customer's nomination variances. Such penalties will be allocated on the basis of each customer's contribution toward the nomination variance.

12. METERING REQUIREMENTS:
    a. Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by customer. Such contribution in aid, as adjusted for federal and state income taxes, shall be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply, or other power source acceptable to the Company and acceptable telephone service at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly transmit data. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company’s remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company’s equipment.

13. DAILY NOMINATION REQUIREMENTS:

a. Customer or customer's shipper and/or agent shall advise the Company's gas nominations center, by 11:30 a.m. Central Clock Time, of the dk requirements customer has requested to be delivered at each delivery point during the following day. Customer's daily nomination shall be its best estimate of the expected utilization for the gas day. Unless other arrangements are made, customer will be required to nominate for the non-business days involved prior to weekends and holidays.

b. All nominations should include shipper and/or agent defined begin and end dates. Shippers and/or agents may nominate for periods longer than

1 day, provided the nomination begin and end dates are within the term of the service agreement.

c. The Company has the sole right to refuse receipt of any volumes which exceed the maximum daily contract quantity and at no time shall the Company be required to accept quantities of gas for customer in excess of the quantities of gas to be delivered to customer. If total nominated receipts exceed total deliveries at receipt points where more than one customer is receiving service, nominations will be allocated on a pro rata basis.

d. At no time shall the Company have the responsibility to deliver gas in excess of customer's nomination.

e. In the event that more than one customer is receiving gas from the same shipper and/or agent at the same receipt point, any reduction in nominated volumes will be allocated on a pro rata basis, unless the Company and shipper(s) and/or agent have agreed to a predetermined allocation procedure.

14. WARRANTY - Customer, customer's agent, or customer's shipper warrants that it will have title to all gas it tenders or causes to be tendered to the Company, and such gas shall be free and clear of all liens and adverse claims and customer, customer's agent, or customer's shipper shall indemnify the Company against all damages, costs, and expenses of any nature whatsoever arising from every claim against said gas.

15. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities

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required to furnish firm gas service, customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. The Company may remove such facilities when service hereunder is terminated.

16. PAYMENT - Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with Rate 100, §V.12, or any amendments or alterations thereto.

17. BILLING ERROR - In the event an error is discovered in any bill that the Company renders to customer, such error shall be adjusted within a period not to exceed 6 months from the date the billing error is first discovered.

18. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder.

19. RULES - The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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LARGE INTERRUPTIBLE GENERAL GAS SERVICE
Rate 85

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$480.00 per month	
Distribution Delivery Charge:	<u>Maximum</u>	<u>Minimum</u>
	$.500 per dk	$.050 per dk
Cost of Gas:	Determined Monthly - See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

General Terms and Conditions:

1. PRIORITY OF SERVICE - Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on firm gas service rates. Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or interrupt such service whenever, in the Company's sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with Rate 100, §V.10.

2. STANDBY REQUIREMENTS:
   a. If Company-approved equipment and fuel for standby service is not installed and maintained, the Company, in its discretion, may install automatic shut-off equipment in order to allow for the interruption of natural gas supply. The cost of the equipment and its installation shall be paid for by customer. The cost shall be the current market price for such equipment including the current installation costs. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the

Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly operate equipment. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the automatic shut-off equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. Customer's firm load must be separately metered if Company-approved equipment and fuel for standby service is not installed and maintained.

3. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT - If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate 70 (distribution delivery charge and cost of gas), plus either an amount equal to any penalty payments or overrun charges the Company is required to make to its interconnecting pipeline(s) under the terms of its contract(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater. The Company, in its discretion, may

shut off customer's supply of gas in the event of customer's failure to curtail or interrupt use of gas when requested to do so by the Company.

4. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for service hereunder. If mutually agreed to by the Company and customer, the term of service reflected in such agreement may be amended. Upon expiration of service, customer may apply for and receive, at the sole discretion of the Company, gas service under another appropriate rate schedule for customer's operations.

5. OBLIGATION TO NOTIFY THE COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify the Company of an anticipated change in daily operations. Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to customer equal to the penalty amounts the Company must pay to the interconnecting pipeline caused by customer's action.

6. METERING REQUIREMENTS:
   a. Remote data acquisition equipment required by the Company for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

b. Customer shall provide and maintain, at no cost to the Company, a 120 volt, 15 ampere, AC power supply or other power source acceptable to the Company and acceptable telephone service available at customer's meter location(s). Customer agrees to provide and maintain, at no cost to the Company, any necessary telephone enhancements to assure the Company of a quality telephone signal necessary to properly transmit data. Customer shall pay all charges for continuous electric and telephone service associated with the Company's connection of the electronic measurement equipment, and any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. The Company reserves the right to charge for each service call to investigate, repair and/or reprogram the Company’s remote data acquisition equipment when the service call is the result of a failure or change in communication or power source provided by customer or damage to Company’s equipment.

7. RULES - The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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GAS COST TRACKING ADJUSTMENT PROCEDURE
Rate 88

1. **Applicability:**
This rate schedule sets forth the procedure to be used in calculating Gas Cost Tracking Adjustments. It specifies the procedure to be utilized to adjust the rates for gas sold under Montana-Dakota's rate schedules in the state of Montana in order to reflect: (a) changes in Montana-Dakota's average cost of gas supply and (b) amortization of the Unreflected Purchased Gas Cost Account.

2. **Effective Date and Limitation on Adjustments:**
   a. Unless otherwise ordered by the Commission, the effective dates of the gas cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Purchased Gas Cost Account shall be October 1 of each year.

   b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of gas supply only when the amount of change in such adjustment is at least 10 (ten) cents per dk. The tracking adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Minimum Filing Requirements:**
Montana-Dakota's filing to implement the Gas Cost Tracking Adjustment effective October 1 of each year shall include the following:

   a. Billing determinants by service agreement by month by supply source, with annual totals;

   b. Rates applicable to those billing determinants;

   c. Purchased gas costs by service agreement by month by supply source, with annual totals;

d. A list of FERC proceedings in which Montana-Dakota has participated with a brief description of the purpose of each and position taken by Montana-Dakota;

e. Total Montana-Dakota sales by major customer class by month with annual totals;

f. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals;

g. If Montana-Dakota has executed a new direct purchase contract since the last October 1 Gas Cost Tracking Adjustment, a description of what efforts, if any, were undertaken to ensure that the contract had pricing provisions which assured a firm supply of gas at a competitive price over the full term of the contract;

h. A description of what efforts, if any, Montana-Dakota has undertaken since the last October 1 Gas Cost Tracking Adjustment to utilize spot gas.

4. Gas Cost Tracking Adjustment:

a. The monthly Gas Cost Tracking Adjustment shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent Gas Cost Tracking Adjustment. The cost of gas supply shall be the sum of all costs incurred in obtaining gas for general system supply. General system supply is defined as gas available for use by all customers served under retail sales rate schedules. The cost of gas supply shall include, but not be limited to, all demand, commodity, storage, gathering, and transportation charges incurred by Montana-Dakota for such gas supply. Any extraordinary costs, such as penalty charges and take-or-pay charges, shall be clearly identified as such and separately described in a supporting exhibit.

b. The Gas Cost Tracking Adjustment shall be computed as follows:

(1) Demand costs shall include all annual gathering, transportation and storage demand charges at current rates.

(2) Commodity costs shall include all annual gathering, transportation and storage charges at current rates.

(3) The gas commodity cost shall reflect all commodity related gas costs estimated to be in effect for the month the gas cost tracking adjustment will be in effect and annual dk requirements.

The cost per dk for the month is the sum of the above divided by annual, weather normalized dk deliveries adjusted to reflect losses.

c. Monthly gas costs shall be calculated as follows:

(1) Demand costs shall be apportioned to all state jurisdictions served by Montana-Dakota on the basis of the overall ratio of each state's Maximum Daily Delivery Quantity (MDDQ).

(2) Demand costs for interruptible sales customers shall be stated on a 100% load factor basis.

(3) All commodity costs and other costs associated with the acquisition of gas for general system supply shall be apportioned to each state on the basis of total dk's sold in each state, regardless of the actual points of delivery of such gas.

(4) All costs related to specific gas transportation services shall not be included in the cost of gas supply determination but shall be directly billed to the customer(s) contracting for such service.

d. The Gas Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules, recognizing differences among customer classes consistent with the cost of gas supply included in the applicable class sales rate.

5. **Unreflected Gas Cost Adjustment:**
All sales rate schedules shall be subject to an Unreflected Gas Cost Adjustment to be effective on October 1 of each year. The Unreflected Gas Cost Adjustment per dk sold shall reflect amortization of the applicable balance in the Unreflected Purchased Gas Cost Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

6. **Unreflected Purchased Gas Cost Account:**
a. Items to be included in the Unreflected Purchased Gas Cost Account, as calculated in accordance with Subsection 6(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in a Gas Cost Tracking Adjustment by reason of the ten cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for gas supplies which were paid during any period after the effective date of the most recent general rate case, but not yet included in sales rates.

GAS COST TRACKING ADJUSTMENT PROCEDURE
Rate 88

(3) Refunds received from supplier(s) with respect to gas supply. Such refunds received shall be credited to the Unreflected Purchased Gas Cost Account.

(4) Demand costs recovered from the interruptible sales customers will be credited to the residential and firm general service customers.

b. The amount to be included in the Unreflected Purchased Gas Cost Account in order to reflect the items specified in Subsections 6(a)(1), (2), and (3) shall be calculated as follows:

(1) Montana-Dakota shall first determine each month the unit cost for that month's natural gas supply as adjusted to levelize demand charges. Such adjustment to levelize supplier(s) demand charges shall be calculated as follows:

The suppliers' annual (calendar or fiscal) demand charges, which are payable in equal monthly payments, shall be accumulated in a prepaid account (FERC Account 165). Each month a portion of such accumulated prepaid amount shall be amortized to cost of natural gas purchased (FERC Account 804). Such monthly amortization shall be based on a rate calculated by dividing the annual supplier(s) demand charges by projected annual dk sales (calendar or fiscal, as appropriate). The resulting product shall then be multiplied by the projected natural gas unit sales for the current month. Such amount shall constitute the monthly amortization of prepaid supplier(s) demand charges to cost of natural gas supply.

(2) Montana-Dakota shall then subtract from each month's unit cost the unit cost for gas supply which is reflected in the currently effective Tracking Adjustment.

(3) The resulting difference (which may be positive or negative) shall be multiplied by the dk's sold during that month under each rate schedule. The resulting amounts shall be reflected in an Unreflected Purchased Gas Cost Account for each rate schedule.

c. Reduction of Amounts in the Unreflected Purchased Gas Cost Account:

(1) The amounts in the Unreflected Purchased Gas Cost Account shall be decreased each month by an amount determined by multiplying the currently effective unreflected gas cost adjustment included in rates for that month (as calculated in Section 5) by the dk's sold during that month under each rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. Time and Manner of Filing:

a. Each filing by Montana-Dakota shall be made by means of revised rate schedule tariff sheets identifying the amounts of the adjustments and the resulting currently effective rates.

b. Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

UNIVERSAL SYSTEM BENEFITS CHARGE Rate 89

Applicability:

In all communities served for all end use sales and transportation service customers for funding of Universal System Benefits (USB) Programs.

Rate:

Charge per dk:

Sales Service Schedules (Rates 60, 70, 71, 72 and 85)	$.0655
Transportation Service Schedules (Rates 80, 81 and 82)	$.0028

Tracking Mechanism:

The rate above shall be subject to adjustment on an annual basis to be effective on May 1. The adjustment shall reflect the true up of actual expenditures associated with approved USB Programs and any adjustments necessary to provide funding at a target level of 0.48% of the prior year's total revenues. A filing to effectuate the May 1 change shall be made by March 1 of each year.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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CONSERVATION PROGRAM TRACKING MECHANISM Rate 90

Applicability:

This rate schedule represents a Conservation Program Tracking Mechanism and specifies the procedure to be utilized to recover the costs of conservation programs, as authorized by the Commission, including the recovery of distribution delivery charge revenues reduced as a result of the conservation programs. Service provided under the Company's Residential Service Rate 60 and Firm General Service Rates 70 and 72 shall be subject to this tracking mechanism.

Conservation Program Tracker:

An adjustment per dk will be determined for each rate schedule subject to the Conservation Program Tracking Mechanism. Monthly bills beginning with bills issued on and after May 1, 2007 and each May 1 thereafter, will be adjusted by the application of the Conservation Tracking Adjustment rate indicated below. The rate will reflect the amortization of the conservation program costs including the dk savings associated with each measure implemented in the prior 12 month period. The currently authorized Distribution Delivery Charge will be applied to the dk savings to compute the reduction in Distribution Delivery revenues associated with the conservation programs. The total program costs including the lost distribution revenues will be amortized over projected volumes to be sold over the next 12 month period. Following the initial one-year term, and annually thereafter, the Conservation Program Tracker rate calculation shall include any over or under collection of revenue from the preceding twelve month recovery period.

Conservation Tracking Adjustment: $0.010 per dk

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

SPECIAL GAS SERVICE Rate 93

Availability:

This service is applicable only to Account No. 270377-21 and Account No. 270340-21 at which the present customers are entitled to receive certain quantities of natural gas from Williston Basin Interstate Pipeline Company (Williston Basin) under the terms of leases with Williston Basin under which natural gas is produced. Williston Basin is obligated to provide such gas to Montana-Dakota at no charge and to reimburse Montana-Dakota for meter reading costs.

Rate:

$0.04 per Mcf

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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CONDITIONS OF SERVICE Rate 100

I. PURPOSE:

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other accepted standards and practices not covered herein. They are intended to ensure adequate service to the public and protect the Company from unreasonable demands.

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of Montana and as supplemented by these general provisions, as now in effect or as may hereafter be lawfully established, and in accepting service from the Company, each customer agrees to comply with and be bound by said rules and regulations and the applicable rate schedules.

II. DEFINITIONS:

The following terms used in this tariff shall have the following meanings, unless otherwise indicated:

AGENT – The party authorized by the transportation service customer to act on that customer's behalf.

APPLICANT - Customer requesting the Company to provide service.

COMMISSION - The Public Service Commission of the State of Montana.

COMPANY - Montana-Dakota Utilities Co. (Montana-Dakota)

COMPANY'S OPERATING CONVENIENCE - The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of the Company's operations. This does not refer to customer's convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.

CURTAILMENT - A reduction of transportation or retail natural gas service deemed necessary by the Company.

CUSTOMER - Any individual, partnership, corporation, firm, other organization or government agency supplied with service by the Company at one location and at one point of delivery unless otherwise expressly provided in these rules or in a rate schedule.

DELIVERY POINT - The point at which customer assumes custody of the gas being transported. This point will normally be at the outlet of the Company's meter(s) located on customer's premises.

GAS DAY - Means a period of 24 consecutive hours, beginning and ending at 9:00 a.m. Central Clock Time.

INTERRUPTION - A cessation of transportation or retail natural gas service deemed necessary by the Company.

NOMINATION - The daily dk volume of the natural gas requested by customer for transportation and delivery to customer at the delivery point during a gas day.

RATE - Shall mean and include every compensation, charge, fare, toll, rental and classification, demanded, observed, charged or collected by the Company for any service, product, or commodity, offered by the Company to the public. This includes any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

RECEIPT POINT - The intertie between the Company and the interconnecting pipeline(s) at which point the Company assumes custody of the gas being transported.

SHIPPER - The party with whom the pipeline has entered into a service agreement with in order to provide transportation service.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE - Customer desiring gas service must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require a signed application or written contract for service to be furnished. All applications and contracts for service must be made in the legal name of customer desiring the service. The Company may refuse an applicant or terminate service to customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any person who uses gas service in the absence of an application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used.

   Subject to rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service. Customer will be responsible for payment of all service furnished through the date of discontinuance.

   Any customer may be required to make a deposit as required pursuant to Rate 100, §V.6.

2. INPUT RATING - All new customers whose consumption of gas for any purpose will exceed an input of 2,500,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates and pressures required for all gas utilization equipment. Where system design capacity permits, such customers may be served on a firm basis. Where system design capacity is limited, and at the Company's sole discretion, the Company will serve all such new customers on an interruptible basis only. Architects, contractors, heating engineers and installers, and all others should consult with the Company before proceeding to design, erect or redesign such installations for the use of natural gas. This will ensure that such equipment will conform to the Company's ability to adequately serve such installations with gas.

3. ACCESS TO CUSTOMER'S PREMISES - Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incident to the service.

4. COMPANY PROPERTY - Customer shall exercise reasonable diligence in protecting the Company's property on their premises and shall be liable to the Company in case of loss or damage caused by their negligence or that of their employees.

5. INTERFERENCE WITH COMPANY PROPERTY - Customer shall not disconnect, change connections, make connections or otherwise interfere with the Company's meters or other property or permit same to be done by other than the Company's authorized employees.

6. RELOCATED LINES - Where Company facilities are located on a public or private utility easement and there is a building encroachment over gas facilities (Company-owned main, Company-owned service line or customer-owned service line) the customer shall be charged for the line re-location on the basis of actual costs incurred by the Company including any required easements.

7. NOTIFICATION OF LEAKS - Customer shall immediately notify the Company at its office of any escape of gas in or about customer's premises.

8. TERMINATION OF SERVICE - Customer is required to notify the Company, to prevent liability for service used by succeeding tenants, when vacating their premises. Upon receipt of such notice, the Company will read the meter and further liability for service used on the part of the vacating customer will cease.

9. REPORTING REQUIREMENTS - Customer shall furnish the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

10. QUALITY OF GAS - The gas tendered to the Company shall conform to the applicable quality specifications of the transporting pipeline's tariff.

IV. LIABILITY:

1. CONTINUITY OF SERVICE - The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same, except when such loss, injury or damage results from the negligence of the Company.

2. CUSTOMER'S EQUIPMENT - Neither by inspection or non-rejection, nor in any other way does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, lines, appliances or devices owned, installed or maintained by customer or leased by customer from third parties.

3. COMPANY EQUIPMENT AND USE OF SERVICE - The Company will not be liable for any loss, injury, death or damage resulting in any way from the supply or use of gas or from the presence or operation of the Company's structures, equipment, lines, appliances or devices on customer's premises, except loss, injuries or damages resulting from the negligence of the Company.

4. INDEMNIFICATION - Customer agrees to indemnify and hold the Company harmless from any and all injury, death, loss or damage resulting from customer's negligent or wrongful acts under and during the term of service. The Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from the Company's negligent or wrongful acts under and during the term of service.

5. FORCE MAJEURE - In the event of either party being rendered wholly or in part by force majeure unable to carry out its obligations, then the obligations of the parties hereto, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused. Such causes or contingencies affecting the performance by either party, however, shall not relieve it of liability in the event of its concurring negligence or in the event of its failure to use due diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve either party from its obligations to make payments of amounts then due hereunder, nor shall such

causes or contingencies relieve either party of liability unless such party shall give notice and full particulars of the same in writing or by telephone to the other party as soon as possible after the occurrence relied on. If volumes of customer's gas are destroyed while in the Company's possession by an event of force majeure, the obligations of the parties shall terminate with respect to the volumes lost.

The term "force majeure" as employed herein shall include, but shall not be limited to, acts of God, strikes, lockouts or other industrial disturbances, failure to perform by any third party, which performance is necessary to the performance by either customer or the Company, acts of the public enemy or terrorists, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrest and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, sudden partial or sudden entire failure of gas supply, failure to obtain materials and supplies due to governmental regulations, and causes of like or similar kind, whether herein enumerated or not, and not within the control of the party claiming suspension, and which by the exercise of due diligence such party is unable to overcome; provided that the exercise of due diligence shall not require settlement of labor disputes against the better judgment of the party having the dispute.

The term "force majeure" as employed herein shall also include, but shall not be limited to, inability to obtain or acquire, at reasonable cost, grants, servitudes, rights-of-way, permits, licenses or any other authorizations from third parties or agencies (private or governmental) or inability to obtain or acquire at reasonable cost necessary materials or supplies to construct, maintain and operate any facilities required for the performance of any obligations under this agreement, when any such inability directly or indirectly contributes to or results in either party's inability to perform its obligations.

V. GENERAL TERMS AND CONDITIONS:

1. AGREEMENT - Upon request of the Company, customer may be required to enter into an agreement for any service.

2. RATE OPTIONS - Where more than one rate schedule is available for the same class of service, the Company will assist customer in selecting the applicable rate schedule(s). The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in customer's load which alters the availability and/or applicability of such rate(s), or unless a change becomes necessary as a result of an order issued by the Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

3. RULES FOR APPLICATION OF GAS SERVICE:
   a. Residential gas service is available to any residential customer for domestic purposes only. Residential gas service is defined as service for general domestic household purposes in space occupied as living quarters, designed for occupancy by one family with separate cooking facilities. Typical service would include the following: single private residences, single apartments, mobile homes with separate meters and auxiliary buildings on the same premise when used for residential purposes by the residential customer. This is not an all-inclusive list.

   b. Nonresidential service is defined as service provided to a business enterprise in space occupied and operated for nonresidential purposes. Typical service would include stores, offices, shops, restaurants, sorority and fraternity houses, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, apartment houses, common areas of shopping malls or apartments (such as halls or basements), churches, elevators, schools and facilities located away from the home site. This is not an all-inclusive list.

c. The definitions above are based upon the supply of service to an entire premise through a single delivery and metering point. Separate supply for the same customer at other points of consumption may be separately metered and billed.

d. If separate metering is not practical for a single unit (one premise) that is using gas for both domestic purposes and for conducting business (or for nonresidential purposes as defined herein), customer will be billed under the predominate use policy. Under this policy, customer's combined service is billed under the rate (residential or nonresidential) applicable to the type of service which constitutes 50% or more of customer's total connected load.

e. Other classes of service furnished by the Company shall be defined in applicable rate schedules, or in rules and regulations pertaining thereto. Service to customers for which no specific rate schedule is applicable shall be billed under the nonresidential rates.

4. DISPATCHING - Transportation customers will adhere to gas dispatching policies and procedures established by the Company to facilitate transportation service. The Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.

5. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES - The rules and regulations for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 - Manufactured Home Construction and Safety Standards) Subparts G and H

which pertain to gas piping and appliance installation. In addition to the above rules, the Company also follows the regulations set forth in the NFPA 501A, Fire Safety Criteria for Manufactured Home Installations, Sites, and Communities. This information is available at Montana-Dakota Utilities Co.'s offices.

6. CONSUMER DEPOSITS - The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with Commission Rules ARM 38.5.1101 through 38.5.1112.

   a. The amount of such deposit for residential service shall not exceed one-sixth of the estimated annual billing. For nonresidential service, the amount of the applicant's deposit shall not exceed 25% of the applicant's estimated annual billing.

   b. The Company shall accept in lieu of a cash deposit a contract signed by a guarantor, whereby the payment of a specified sum not to exceed an estimated one year bill shall be guaranteed. Such estimation shall be made at the time the service is established. Guarantee terms and conditions will be in accordance with Commission Rules ARM 38.5.1111 and 38.5.1112.

      Interest on deposits held shall be accrued at the rate set forth in Rate 100, §VI.3. Interest shall be computed from the time of deposit to the time of refund or of termination. Interest shall be credited to customer's account annually during the month of December.

      Deposits with interest shall be refunded to customers at termination of service provided all billings for service have been paid. Deposits with interest will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record, as defined in the Commission rules, has been established.

7. METERING AND MEASUREMENT:
   a. The Company will meter the quantity of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both parties unless such meter is found to be inaccurate, in which case the quantity supplied to customer shall be determined by as correct an estimate as it is possible to make, taking into consideration the time of year, the schedule of customer's operations and other pertinent facts. The Company will test meters in accordance with applicable state utility rules and regulations.

   b. Transportation customers agree to provide the cost of the installation of electronic measurement equipment to the Company before transportation service is implemented.

8. MEASUREMENT UNIT FOR BILLING PURPOSES - The measurement unit for billing purposes shall be one (1) decatherm (dk), unless otherwise specified. Billing will be calculated to the nearest one-tenth (1/10) dk. One dk equals 10 therms or 1,000,000 Btu's. Dk's shall be calculated by the application of a thermal factor to the volumes metered. This thermal factor consists of:
   a. An altitude adjustment factor used to convert metered volumes at local sales base pressure to a standard pressure base of 14.73 psia, and

   b. A Btu adjustment factor to reflect the heating value of gas delivered.

9. UNIT OF VOLUME FOR MEASUREMENT - The unit of volume for purpose of measurement shall be one (1) cubic foot of gas at either local sales base pressure or 14.73 psia, as appropriate, and a temperature base of 60 degrees Fahrenheit (60 F). All measurement of natural gas by orifice meter shall be

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reduced to this standard by computation methods, in accordance with procedures contained in ANSI-API Standard 2530, First Edition, as amended. Where natural gas is measured with positive displacement or turbine meters, correction to local sales base pressure shall be made for actual pressure and temperature with factors calculated from Boyle's and Charles' Laws. Where gas is delivered at 20 psig or more, the deviation of the natural gas from Boyle's Law shall be determined by application of Supercompressibility Factors for Natural Gas published by the American Gas Association, Inc., Copyright 1955, as amended or superseded. Where gas is measured with electronic correcting instruments at pressures greater than local sales base, supercompressibility will be calculated in the corrector using AAGA-3/NX-19, as amended, supercompressibility calculation. For handbilled accounts, application of supercompressibility factors will be waived on monthly billed volumes of 250 dk or less.

10. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY - Priority of Service from highest to lowest:
    a. Priority 1 - Firm sales service.
    b. Priority 2 - Small interruptible sales on a pro rata basis.
    c. Priority 3 - Large interruptible sales on a pro rata basis.
    d. Priority 4 - Small interruptible transportation services at the maximum rate on a pro rata basis.
    e. Priority 5 - Large interruptible transportation services at the maximum rate on a pro rata basis.
    f. Priority 6 - Small interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
    g. Priority 7 - Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.

h. Priority 8 - Gas scheduled to clear imbalances.

Montana-Dakota shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Montana-Dakota's system.

Montana-Dakota reserves the right to provide service to customers with a lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Montana-Dakota will reinstate sales and/or transportation of gas according to each customer's original priority.

11. REPORTING REQUIREMENTS - Customer shall furnish the Company all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the matter herein.

12. LATE PAYMENT - Amounts billed for energy or transportation services will be considered past due if not paid by the due date shown on the bill.

For residential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the second subsequent billing date provided, however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment arrangement, an amount equal to the percentage set forth in Rate 100, §VI.2 of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

For nonresidential customers, an amount equal to the percentage set forth in Rate 100, §VI.2 will be applied to any unpaid balance existing at the immediate subsequent billing date.

All payments received will apply to customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

13. RETURNED CHECK CHARGE - A charge as set forth in Rate 100, §VI.1.b. will be collected by the Company for any check not honored by customer's bank for any reason.

14. TAX CLAUSE - In addition to the charges provided for in the gas tariffs of the Company, there shall be charged pro rata amounts which, on an annual basis, shall be sufficient to yield to the Company the full amount of any usage fees or any sales, use, franchise, or excise taxes, whether they be denominated as license taxes, occupation taxes, business taxes, privilege taxes, or otherwise, levied against or imposed upon the Company by any municipality, political subdivision, or other entity, for the privilege of conducting its utility operations therein.

    The charges to be added to customer's service bills under this clause shall be limited to customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.

15. UTILITY CUSTOMER SERVICES:
    a. The following services will be performed at no charge regardless of the time of performance:

        1. Responding to fire and explosion calls.

        2. Investigating hazardous conditions on customer premises, such as gas leaks, odor complaints and combustion gas fumes.

        3. Maintenance or repair of Company-owned facilities on customer's premises.

        4. Pilot relighting will be performed at no charge two (2) times per calendar year per customer. Additional pilot relights will be performed on a chargeable basis. Customers that qualified for the Low Income Energy Assistance Program (LIEAP) during the current LIEAP year will not be charged for a pilot relight.

    b. The following service calls will be performed at no charge during the Company's regular business hours:

        1. Reconnecting service to an existing facility (cut-in) or disconnecting service (cut-out).

        2. Lighting pilots, inspecting and adjusting gas equipment in connection with establishing service when working cut-in orders.

        3. Investigating high bills or inadequate service complaints.

        4. Locating underground Company facilities and customer-owned gas service lines for contractors, builders, plumbers, etc.

5. Investigating noisy meter complaint.

6. Flue analysis on heating equipment (CO test).

7. Moving meter from inside to outside.

8. Service calls for routine cut-ins, when the order is received prior to 12:00 p.m. on a regular work day, will be considered as non-chargeable regardless if work is performed outside of normal working hours.

16. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS - For service requested by customers after the Company's normal business hours and on Saturdays, Sundays, or legal holidays, a charge will be made for labor at the overtime service rate set forth in Rate 100, §VI.1.f. and material at retail prices.

    Customers requesting service after the Company's normal business hours will be informed of the after-hour service rate and encouraged to have the service performed during normal business hours.

17. NOTICE TO DISCONTINUE GAS SERVICE - Customers desiring to have their gas service discontinued shall notify the Company during regular business hours, one business day before service is to be disconnected. Such notice shall be by letter, personal visit or telephone call to the Company's business office. Saturdays, Sundays and legal holidays are not considered business days.

18. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE - A customer requesting a temporary meter installation and service will be charged for such installation in accordance with Rate 100, §VI.1.i.

19. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER - A customer who requests reconnection of service, at a location where same customer discontinued the same service during the preceding 12-month period will be charged $30.00 during normal business hours. The charge will be based on standard overtime rates for reconnecting service after normal business hours.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a reconnection charge as set forth in Rate 100, §VI.1.e. whenever reinstallation of the required remote data acquisition equipment is necessary.

20. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILLS - All amounts billed for services are due when rendered and become delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of amounts billed, such service may be discontinued by the Company under the applicable rules of the Commission. The Company may collect a fee, as set forth in Rate 100, §V.19., before restoring gas service which has been disconnected for non-payment of service bills. Customers that qualified for the Low Income Energy Assistance Program during the current LIEAP program year will be subject to a reconnection charge of $12.00.

21. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS - The Company reserves the right to discontinue service for any of the following reasons:
    a. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

    b. In the event of tampering with the equipment furnished and owned by the Company.

c. For violation of, or noncompliance with, the Company's rules on file with the Commission.

d. For failure of customer to fulfill the contractual obligations imposed as conditions of obtaining service.

e. For refusal of reasonable access to property to the agent or employee of the Company for the purpose of inspecting the facilities or for testing, reading, maintaining or removing meters.

The right to discontinue service for any of the above reasons may be exercised whenever and as often as such reasons may occur, and any delay on the part of the Company in exercising such rights, or omission of any action permissible hereunder, shall not be deemed a waiver of its rights to exercise same.

Nothing in these regulations shall be construed to prevent discontinuing service without advance notice for reasons of safety, health, cooperation with civil authorities, or fraudulent use, tampering with or destroying the Company's facilities.

The Company may collect a reconnect fee, as set forth in Rate 100, §V.19. before restoring gas service which has been disconnected for the above causes.

22. UNAUTHORIZED USE OF SERVICE - Unauthorized use of service is defined as any deliberate interference such as tampering with the Company's meter, pressure regulator, registration, connections, equipment, seals, procedures or records that result in a loss of revenue to the Company. Unauthorized service is also defined as reconnection of service that has been terminated, without the Company's consent.

    1. Types of unauthorized use of service:

        a. Bypass piping around meter.
        b. Bypass piping installed in place of meter.
        c. Meter reversed.
        d. Meter index disengaged or removed.
        e. Service or equipment tampered with or piping connected ahead of meter.
        f. Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
        g. Gas being used after service has been discontinued by the Company.
        h. Gas being used after service has been discontinued by the Company as a result of a new customer turning gas on without the proper connect request.

    2. Any cost incurred to repair damage to company-owned property installed on customer's premise will be billed to customer. If no physical damage has occurred, customer shall be charged for
        a. Time, material and transportation costs used in investigation or surveillance.
        b. Estimated charge for non-metered gas.

c. On-premise time to correct situation.
d. A minimum fee of $30.00 will apply.

3. Reconnection of Service:

Gas service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service and paid all service charges as hereinafter set forth in this procedure:

a. All delinquent bills, if any;
b. The amount of any Company revenue loss attributable to said tampering;
c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
d. Reconnection fee applicable; and
e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

23. RATE FOR EMPLOYEES - The rate for residential gas service for regular full-time employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc. shall be computed at the applicable rate and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular full-time employee who has been continuously employed at least six months and is the principal support of the household in which employee resides or is the spouse of the principal support.

24. RATES FOR SPECIAL PROVISIONS:
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - New Installation, Replacement,
Relocation and Repair of Gas Service Lines

VI. MISCELLANEOUS CHARGES	Amount or <u>Reference</u>
1. Service Charges	
a. Consumer deposits	Rate 100, §V.6
b. Returned check	$20.00
c. Minimum reconnect charge after termination for nonpayment or other causes	
- During normal business hours	$30.00 ($12.00 for LIEAP)
- After normal business hours	standard overtime rates
d. Minimum reconnect charge applicable to seasonal or temporary customers	
- During normal business hours	$30.00
- After normal business hours	standard overtime rates
e. Reconnection charge applicable to transport customers when electronic metering must be reinstalled	$160.00

f.	Service request after normal business hours	Materials & labor at standard overtime rates
g.	Interruptible service main extension	Rate 119
h.	Firm service main extension	Rate 120
i.	Installation of temporary metering or service facilities	Materials & labor
j.	New installation, replacement, relocation and repair of gas service lines	Rate 124

	Per Month	Approx. Annual Percent
2. Late Payment Charges (on unpaid balance)	1%	12%
3. Interest on Consumer Deposits	0.5%	6%

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INTERRUPTIBLE GAS SERVICE EXTENSION POLICY
Rate 119

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide interruptible sales or interruptible transportation service to customers is as follows:

1. Contribution
   a. Prior to construction, the customer shall contribute an amount equal to the total cost of construction including all gas main extensions, valves, service line(s) , regulators, meters (excluding remote data equipment), any required payments made by the Company to the transmission pipeline to accommodate the extensions, and other costs as adjusted for applicable federal and state income taxes. Such tax amount will be calculated in accordance with the provisions of the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

   b. The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. The customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the total contribution required prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for a five-year period commencing at the plant in-service date, and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists for the subject project, the surety or guarantor shall pay the Company for such contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, and 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. Remote data acquisition equipment costs shall be subject to the terms and conditions specified in Transportation Service Rates 81 and 82.

2. Refund

a. If within the five-year period from the extension(s) in-service date, the total of the customer's contribution and actual margin paid to the Company equals or exceeds the total present value of the revenue requirement associated with the extension, Company shall refund the amount exceeding the revenue requirement on the following basis:

i. Annually, beginning at the second anniversary of the extension(s) in-service date, the Company will refund to the customer, the amount exceeding the total present value of the revenue requirement at a rate of 50% of the current year margin associated with the customer's actual throughput.

ii. Customers who have posted a bond, letter of credit or a written guarantee commitment will be notified of any reduction in surety or guarantee requirements based on the above calculation.

iii. No refunds will be made for amounts less than $25.

b. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

c. No refund shall be made by the Company after the five-year refund period has expired, and in no case shall the refund, excluding interest, exceed the amount of contribution made by the customer.

The policy of Montana-Dakota Utilities Co. for gas main extensions necessary to provide firm sales or firm transportation service to customers is as follows:

A. General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in paragraph A.3.

2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.

3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

   Maximum Allowable Investment =

   Annual Basic Service Charge + (Project Estimated 3rd Year Annual Dk x Distribution Delivery Charge)/Levelized Annual Revenue Requirement Factor

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs excluding the distribution meter and regulator.

5. Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer or the developer and Company.

6. A refund will be made only when there is a reduction in the amount of contribution required within a five-year period from the extension(s) in-service date. Interest will be calculated annually by the Company on any refund amounts and shall be equal to the average commercial paper interest rate (A1/P1), not to exceed 12 percent per annum.

   No refund shall be made by Company after the five-year refund period, and in no case shall the refund, excluding interest, exceed the amount of the contribution.

7. The Company reserves the right to charge customer the cost associated with providing service to customer if service is not initiated within 12 months of such installation.

B. Customer Extensions

Cost participation for extensions where customers will be immediately available for service is as follows:

1. Contribution -

   a. When a contribution is required, the customer(s) shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3., plus an amount for applicable federal and state income taxes. Such tax amount will be calculated in accordance with the provisions of the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

   b. The contribution shall be made by:

      i. A one-time payment prior to construction, or

      ii. Payment of 25% of the contribution prior to construction and the balance in no more than twenty-four equal monthly installments. If customer discontinues service within the twenty-four month period, the balance will be due and payable upon discontinuance of service, or

      iii. Customer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety or guarantor shall reimburse the Company for such recalculated contribution requirement, or

iv. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, and 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

d. If within the five-year period from the extension(s) in-service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment.

e. The recalculated contribution requirement shall be collected from the new applicant(s).

2. Refund -

a. The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Customers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

b. No refunds will be made until the new applicants begin taking service from the Company.

c. If the addition of new customers will increase the contribution required from existing customer(s), the extension will be considered a new extension and treated separately.

3. Incremental Expansion Surcharge -

a. The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to groups of customers requesting service totaling 10 or more when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the Maximum Allowable Investment determined in accordance with ¶A.3.

i. A minimum up-front payment of $100.00 will be collected from each customer who signs an agreement to participate in the expansion.

ii. For projects that are expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus $1.50 per dk.

iii. For projects that are not expected to be recovered within a 5-year period, the Surcharge shall be set at a fixed monthly charge of $5.00 per month plus a commodity charge designed to provide recovery of the contribution requirement in a 5-year period.

b. The Surcharge shall remain in effect until the net present value of the contribution requirement, calculated using a discount rate equal to the overall rate of return authorized in the last rate case, is collected.

c. The Surcharge shall apply to all customers connecting to natural gas service within the expansion area until the contribution requirement is satisfied.

d. The net present value of the Surcharge will be treated as a contribution-in-aid of construction for accounting purposes.

C. Developer Extensions

Cost participation may be required for extension(s) such as a subdivision or mobile home court, in which a developer is installing roads, utilities, etc., before housing is built.

1. Contribution -

a. When a contribution is required, the developer shall pay the Company the portion of the capital expenditure not cost justified as determined in accordance with paragraph A.3., plus an amount for applicable federal and state income taxes. Such tax amount will be calculated in accordance with the Commission's Order in Docket No. 86.11.62, Order No. 5236(f).

b. The contribution shall be made by:

i. A one-time payment prior to construction, or

ii. Developer may post a bond, irrevocable letter of credit, or a written guarantee commitment in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, letter of credit, or written guarantee commitment, shall be effective for the original five-year term and is subject to approval and acceptance by the Company. If at the end of the original five-year term, a contribution requirement exists in the subject project based on a recalculated maximum expenditure, the surety shall reimburse the Company for such recalculated contribution requirement, or

iii. Customer, upon approval by Company, may finance the amount of the required contribution subject to the following conditions: 1) maximum contribution to be financed shall be determined by the Company at its sole discretion, 2) maximum term shall be five years, and 3) interest will be charged at the Company's incremental weighted cost of capital.

c. Upon completion of construction, the contribution amount will be adjusted to reflect actual costs, and an additional charge may be levied or a refund may be made.

2. Refund -

   a. If within the five-year period from the extension(s) in-service date, the number of active customers and related volumes exceeds the third-year projections, the Company shall recompute the contribution requirement by recalculating the maximum allowable investment. Such recalculation shall be done annually based upon the anniversary of the extension(s) in-service date.

   b. The Company will refund to the developer the amount required to reduce their contribution to the recalculated contribution requirement. No refunds will be made for amounts less than $25. Developers who have posted a bond, letter of credit, or written guarantee commitment will be notified of any reduction in surety or guarantee requirements.

   c. If the addition of new customer(s) will increase the contribution required from the developer, the extension will be considered a new extension and treated separately.

Montana-Dakota Utilities Co.
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NEW INSTALLATION, REPLACEMENT, RELOCATION AND REPAIR OF GAS SERVICE LINES Rate 124

1. The Company will install, at its expense, a service line extending from the main to the connection at the premise regulator and/or meter for all customers connected on and after (effective date of tariff) and all replacement service lines installed on and after (effective date of tariff). The service line installed by the Company will remain the Company's property.

2. A non-refundable contribution may be required for that portion of the service line cost not supported by the expected or actual connected load. The contribution requirement will be determined based on minimum footage allowances determined annually taking into account the maximum allowable investment defined in Rate 120 and the average installed per foot cost. The Company reserves the right to charge customer the total cost of the installed service line if service is not initiated within 12 months of such installation.

3. The portion of the service line not cost justified shall be charged to the customer on the basis of direct costs to the Company. The Company may, at its option, calculate a statewide average cost per foot for such work based on its experience and may use such calculated amount for billing purposes. No minimum amount shall apply.

4. Where service line location changes are made due to building encroachments (a building is being constructed or is already located over a service line, etc.), customer shall be charged on the basis of direct costs incurred by the Company.

5. Whenever a service line is damaged by the customer or someone under the employ of the customer necessitating the service line to be either repaired or replaced in whole or in substantial part, such work shall be charged for on a direct cost basis. If the damage was caused by independent contractors, not in the employ of customer, the charges shall be billed directly to such contractor.

6. Service line changes necessary to increase the size and capacity of an existing service line because of increased demand shall be treated in accordance with ¶ 2. above.

Appendix B

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

Volume No. 6
3rd Revised Sheet No. 1
Canceling 2nd Revised Sheet No. 1

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Issued: September 26, 2012

By: Tamie A. Aberle
Director - Regulatory Affairs

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RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$0.35 per day
Distribution Delivery Charge:	$0.998 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

Low-Income Discount:

Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP assistance.

% Of Federal Poverty	Discount Rate
0-60%	30%
61%-90%	25%
91%-maximum allowed	20%

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.40 per day
For customers with meters rated over 500 cubic feet per hour	$0.80 per day
Distribution Delivery Charge:	$1.457 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$175.00 per month	
Distribution Delivery Charge:	Maximum $0.734 per dk	Minimum $0.101 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.40 per day
For customers with meters rated over 500 cubic feet per hour	$0.80 per day
Distribution Delivery Charge:	$1.457 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Montana-Dakota Utilities Co.
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Natural Gas Service

Reserved for future use

Reserved for future use

Rate:

Basic Service Charge:

Rate 81	Rate 82
$225.00 per month	$655.00 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$0.734	$0.500
Minimum Rate per dk	$0.101	$0.050
Fuel Charge (Applicable to all dk transported)*	See Rate Summary Sheet	
Balancing Charge per dk	$0.300	$0.300

* Fuel charge does not apply to transmission level customers.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

General Terms and Conditions:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE- To qualify for gas transportation service, customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$605.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$.500 per dk	$.050 per dk
Cost of Gas:	Determined Monthly - See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Applicability:

This rate schedule represents a Distribution Delivery Stabilization Mechanism (DDSM) and specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the billing period from November 1 through May 1. Service provided under the Company's Residential Rate 60 and Firm General Service Rate 70 shall be subject to adjustment under the DDSM.

Distribution Delivery Stabilization Mechanism:

A DDSM will be determined for each customer taking service under Residential Service Rate 60 and Firm General Service Rate 70 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied on a real-time basis as a surcharge or credit on all rate schedules to which the DDSM is applicable to the customers' bills issued each month during the weather adjustment period of November 1 through May 1.

DDSM Adjustment Calculation:

The DDSM Adjustment shall be determined for each customer taking service under Residential Rate 60 or Firm General Service Rate 70. In order to calculate the respective DDSM adjustment, the ratio of the normal HDDs as compared to the actual HDDs will be determined and multiplied by the temperature sensitive consumption per customer per HDD. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

$$DDSM_i = R_i\,(DDF_i\,((NDD-ADD)/ADD))$$

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 60 and 70
R_i	=	Applicable Distribution Delivery Charge per dk
DDF_i	=	Temperature sensitive use per customer
NDD	=	Normal degree days for the applicable bill cycle
ADD	=	Actual heating degree days for the applicable bill cycle

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Definitions:

Heating Degree Days (HDD)	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days (NDD)	-	The heating degree days based on the 30-year average actual degree days
Temperature Sensitive Use per Customer	-	Customer's actual use less the base use per customer per day, denoted below, multiplied by days in the billing period. Residential Rate Code 60 = .04849 Firm General Service Rate Code 700 = .03523 Firm General Service Rate Code 701 = .85061
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in Montana.

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Natural Gas Service

SPECIAL GAS SERVICE Rate 93

Availability:

This service is applicable only to Account No. 270377-21 and Account No. 270340-21 at which the present customers are entitled to receive certain quantities of natural gas from WBI Energy under the terms of leases with WBI Energy under which natural gas is produced. WBI Energy is obligated to provide such gas to Montana-Dakota at no charge and to reimburse Montana-Dakota for meter reading costs.

Rate:

$0.04 per Mcf

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

c. On-premise time to correct situation.
d. A minimum fee of $30.00 will apply.

3. Reconnection of Service:

   Gas service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service and paid all service charges as hereinafter set forth in this procedure:

   a. All delinquent bills, if any;
   b. The amount of any Company revenue loss attributable to said tampering;
   c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
   d. Reconnection fee applicable; and
   e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

23. RATE FOR EMPLOYEES – The rate for residential gas service for regular full-time employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc. shall be computed at the applicable rate and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular full-time employee who has been continuously employed at least six months and is the principal support of the household in which employee resides or is the spouse of the principal support.

Tariffs Reflecting Proposed Changes

Public Service Commission of Montana

Montana-Dakota Utilities Co.
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Natural Gas Service

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By: Tamie A. Aberle
Regulatory Affairs Manager

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Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
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RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$~~6.35~~0.35 per ~~month~~day
Distribution Delivery Charge:	$~~1.126~~0.998 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

Low-Income Discount:

Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP assistance.

% Of Federal Poverty	Discount Rate
0-60%	30%
61%-90%	25%
91%-maximum allowed	20%

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:

For customers with meters rated under 500 cubic feet per hour	$~~10.40~~0.40 per ~~month~~day
For customers with meters rated over 500 cubic feet per hour	$~~22.05~~0.80 per ~~month~~day
Distribution Delivery Charge:	$~~1.353~~1.457 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Distribution Delivery Stabilization Mechanism:

Service under this rate schedule is subject to an adjustment for the effects of weather in accordance with the Distribution Delivery Stabilization Mechanism Rate 87 or any amendments or alterations thereto.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Conservation Tracking Adjustment:

Service under this rate schedule is subject to a charge for the Conservation Program Tracking Mechanism as set forth in Rate 90 or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE
Rate 71

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas fueled load will exceed an input rate of 2,500,000 Btu per hour, metered at a single delivery point and whose use of natural gas will not exceed 100,000 dk annually. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$~~125.00~~175.00 per month	
Distribution Delivery Charge:	Maximum $~~.742~~0.734 per dk	Minimum $0.101 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$~~10.40~~0.40 per ~~month~~day
For customers with meters rated over 500 cubic feet per hour	$~~22.05~~0.80 per ~~month~~day
Distribution Delivery Charge:	$~~1.353~~1.457 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Issued:

By: Tamie A. Aberle
Regulatory Affairs Manager

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~~Availability:~~

~~This service is available to the Miles City and Glendive combustion turbines and the Lewis & Clark steam generating unit for transportation of natural gas on an interruptible basis to these facilities for the sole purpose of electric generation.~~

~~Basic Service Charge:~~ ~~$175.00 per month~~

~~Transportation Charge:~~

~~Customer shall pay a calculated rate as specified herein, not more than the maximum nor less than the minimum set forth below.~~

~~Maximum~~	~~$.742 per dk~~
~~Minimum~~	~~$.101 per dk~~

~~Universal System Benefits Charge:~~

~~Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.~~

~~Calculation of Transportation Charge:~~

~~The transportation charge for gas used for generation sales to Mid-Continent Area Power Pool (MAPP) will be calculated as follows:~~

~~The price quoted to MAPP (excluding any MAPP loss factor) less the applicable pool adder for the particular MAPP schedule under which the sale is being made, less turbine start-up costs, less maintenance costs, less cost of fuel(s) and less pipeline transportation charges. In no event, shall the gas transportation charge hereunder be less than the minimum rate nor more than the maximum rate.~~

Reserved for future use

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

Volume No. 6
1st Revised Sheet No. 31.1
Canceling Original Sheet No. 31.1

~~ELECTRIC GENERATION INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80~~

~~The transportation charge for gas used for generation for Montana-Dakota's native load will be calculated as follows:~~

> ~~The price quoted by others for a MAPP sale to Montana-Dakota less turbine start-up costs, less maintenance costs, less cost of fuel(s) and less pipeline transportation charges. In no event, shall the gas transportation charge hereunder be less than the minimum rate nor more than the maximum rate.~~

~~Price Flexibility:~~

~~Transportation charges may be flexed by individual transaction on an hourly basis.~~

~~General Terms and Conditions:~~

1. ~~The transportation service general terms and conditions under Rates 81 and 82 are all applicable to this rate.~~

2. ~~Gas transported under this Rate 80 shall not be considered system supply gas as defined in Rate 88.~~

Reserved for future use

Issued:

By: Tamie A. Aberle
Regulatory Affairs Manager

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Rate:

Basic Service Charge:

Rate 81	Rate 82
$~~175.00~~225.00 per month	$~~530.00~~655.00 per month

Transportation Charges:	Rate 81	Rate 82
Maximum Rate per dk	$~~0.742~~0.734	$0.500
Minimum Rate per dk	$0.101	$0.050
Fuel Charge (Applicable to all dk transported)*	See Rate Summary Sheet	
Balancing Charge per dk	$0.300	$0.300

* Fuel charge does not apply to transmission level customers.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

General Terms and Conditions:

1. CRITERIA FOR SERVICE – In order to receive the service, customer must qualify under one of the Company's applicable natural gas transportation service rates and comply with the general terms and conditions of the service provided herein. Customer is responsible for making all arrangements for transporting the gas from its source to the Company's interconnection with the delivering pipeline(s).

2. REQUEST FOR GAS TRANSPORTATION SERVICE- To qualify for gas transportation service, customer must request the service pursuant to the provisions set forth herein. The service shall be provided only to the extent that the Company's existing operating capacity permits.

LARGE INTERRUPTIBLE GENERAL GAS SERVICE
Rate 85

Availability and Applicability of Service:

In all communities served for all interruptible general gas service customers whose interruptible natural gas requirements will exceed 100,000 dk annually as metered at a single delivery point. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. Customer's firm load shall be treated and billed in accordance with the provisions of Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

The Company reserves the right to refuse the initiation of service under this rate schedule based on the availability of gas supply.

Rate:

Basic Service Charge:	$~~480.00~~605.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$.500 per dk	$.050 per dk
Cost of Gas:	Determined Monthly - See Rate Summary Sheet for Current Rate	

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Applicability:

This rate schedule represents a Distribution Delivery Stabilization Mechanism (DDSM) and specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the billing period from November 1 through May 1. Service provided under the Company's Residential Rate 60 and Firm General Service Rate 70 shall be subject to adjustment under the DDSM.

Distribution Delivery Stabilization Mechanism:

A DDSM will be determined for each customer taking service under Residential Service Rate 60 and Firm General Service Rate 70 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied on a real-time basis as a surcharge or credit on all rate schedules to which the DDSM is applicable to the customers' bills issued each month during the weather adjustment period of November 1 through May 1.

DDSM Adjustment Calculation:

The DDSM Adjustment shall be determined for each customer taking service under Residential Rate 60 or Firm General Service Rate 70. In order to calculate the respective DDSM adjustment, the ratio of the normal HDDs as compared to the actual HDDs will be determined and multiplied by the temperature sensitive consumption per customer per HDD. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

$$DDSM_i = R_i\,(DDF_i\,((NDD-ADD)/ADD))$$

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 60 and 70
R_i	=	Applicable Distribution Delivery Charge per dk
DDF_i	=	Temperature sensitive use per customer
NDD	=	Normal degree days for the applicable bill cycle
ADD	=	Actual heating degree days for the applicable bill cycle

Definitions:

Heating Degree Days (HDD)	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days (NDD)	-	The heating degree days based on the 30-year average actual degree days
Temperature Sensitive Use per Customer	-	Customer's actual use less the base use per customer per day, denoted below, multiplied by days in the billing period. Residential Rate Code 60 = .04849 Firm General Service Rate Code 700 = .03523 Firm General Service Rate Code 701 = .85061
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in Montana.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

SPECIAL GAS SERVICE Rate 93

Availability:

This service is applicable only to Account No. 270377-21 and Account No. 270340-21 at which the present customers are entitled to receive certain quantities of natural gas from ~~Williston Basin Interstate Pipeline Company (Williston Basin)~~WBI Energy under the terms of leases with ~~Williston Basin~~WBI Energy under which natural gas is produced. ~~Williston Basin~~WBI Energy is obligated to provide such gas to Montana-Dakota at no charge and to reimburse Montana-Dakota for meter reading costs.

Rate:

$0.04 per Mcf

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 -124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

c. On-premise time to correct situation.
d. A minimum fee of $30.00 will apply.

3. Reconnection of Service:

Gas service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service and paid all service charges as hereinafter set forth in this procedure:

a. All delinquent bills, if any;
b. The amount of any Company revenue loss attributable to said tampering;
c. Expenses incurred by the Company in replacing or repairing the meter or other appliance, costs incurred in preparation of the bill, plus costs as outlined in Paragraph 2 above;
d. Reconnection fee applicable; and
e. A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules ARM 38.5.1105.

23. ~~RATE FOR EMPLOYEES – The rate for residential gas service for regular full-time employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc. shall be computed at the applicable rate and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular full-time employee who has been continuously employed at least six months and is the principal support of the household in which employee resides or is the spouse of the principal support.~~ RATE FOR EMPLOYEES –

The rate for residential gas service for regular full-time employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc. shall be computed at the applicable rate and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular full-time employee who has been continuously employed at least six months and is the principal support of the household in which employee resides or is the spouse of the principal support.

24. RATES FOR SPECIAL PROVISIONS:
Rate 119 - Interruptible Gas Service Extension Policy
Rate 120 - Firm Gas Service Extension Policy
Rate 124 - New Installation, Replacement, Relocation and Repair of Gas Service Lines

VI. MISCELLANEOUS CHARGES	Amount or Reference
1. Service Charges	
a. Consumer deposits	Rate 100, §V.6
b. Returned check	$20.00
c. Minimum reconnect charge after termination for nonpayment or other causes	
- During normal business hours	$30.00 ($12.00 for LIEAP)
- After normal business hours	standard overtime rates
d. Minimum reconnect charge applicable to seasonal or temporary customers	
- During normal business hours	$30.00

	- After normal business hours	standard overtime rates		
e.	Reconnection charge applicable to transport customers when electronic metering must be reinstalled	$160.00		
f.	Service request after normal business hours	Materials & labor at standard overtime rates		
g.	Interruptible service main extension	Rate 119		
h.	Firm service main extension	Rate 120		
i.	Installation of temporary metering or service facilities	Materials & labor		
j.	New installation, replacement, relocation and repair of gas service lines	Rate 124		

	Per Month	Approx. Annual Percent
2. Late Payment Charges (on unpaid balance)	1%	12%
3. Interest on Consumer Deposits	0.5%	6%

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

Before the Public Service Commission of Montana

Docket No. D2012.9.___

Direct Testimony
of
David L. Goodin

Q. Please state your name and business address.

A. My name is David L. Goodin and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

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

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

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above mentioned Companies.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical and Electronics Engineering from North Dakota State University and a Masters of Business Administration Degree from the University of North Dakota. I also completed the Advanced Management Program at Harvard University in 2006. My work experience includes five years as a field Electrical Engineer; five years as division Electric Superintendent overseeing crews, servicepersons, and office personnel in constructing and maintaining Montana-Dakota's electric system; six years overseeing its Electric System Operations Dispatch Center, and in 2000 I became the Vice President – Operations for Montana-Dakota. In January 2007 I was promoted to Executive Vice President of Operations and Acquisitions and in July 2007 became President of Cascade Natural Gas Company. I was additionally named President of Montana-Dakota and Great Plains in March 2008 and President of Intermountain Gas Company in October 2008. I am a Professional Engineer registered in North Dakota.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously testified before this Commission and the Public Service Commissions of North Dakota and Wyoming and the Washington Utilities and Transportation Commission and have submitted written testimony in proceedings before the Oregon Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's Montana natural gas operations, explain our request for a natural gas distribution rate increase and discuss the policies and reasons underlying the major aspects of the request. I will also address the request for an interim increase and introduce the other Company witnesses that will present testimony and exhibits in further support of the Company's request.

Q. Would you provide a summary of Montana-Dakota's gas operations in Montana?

A. Montana-Dakota provides natural gas service to approximately 78,910 customers in 37 communities. As of December 31, 2011, the Company had 136 full and part time employees who live and work throughout our Montana electric and gas service area. Montana-Dakota's Montana gas service area is divided into two operating regions with regional offices located in Billings, Montana and Dickinson, North Dakota and a number of smaller district offices located in communities throughout Montana.

The residential, firm general service and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter with summer loads being small by comparison. The total annual gas used by our Montana customers is 15.0 Mmdk as identified for the test period in this case. Consumption by customer class is as follows: 41 percent residential, 25 percent firm general service, 6 percent small interruptible, and 28 percent large interruptible.

Q. Q. Mr. Goodin, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for a natural gas rate increase?

A. Montana-Dakota is requesting an increase in its general gas rates at this time because our current rates do not reflect the cost of providing natural gas service to our Montana customers.

Q. Would you please describe the basic elements that make up the total costs of providing natural gas service?

A. For a natural gas distribution utility, the basic elements which make up the cost of providing natural gas service are the cost of gas purchased at the town border stations in its service territory and the cost of distributing the gas from the town border station to the end use customer. It is the second of these two elements, the distribution costs, which are the subject of this application for a general rate increase.

The natural gas we purchase from suppliers in our service area is a commodity like wheat or corn, the price of which is not regulated. The cost of delivering the gas to our distribution system at the town border station is regulated by the Federal Energy Regulatory Commission or other regulatory agencies. These gas costs are passed on to our customers on a dollar-for-dollar basis as specified in our Commission approved Gas Cost Tracking Adjustment tariff. The gas cost portion of our cost of providing natural gas service comprises about 66 percent of a typical residential bill for gas service.

The distribution cost portion of our rates is the subject of this proceeding. This portion includes operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on the investment we have in facilities to provide natural gas service. The distribution costs are about 34 percent of a typical residential bill.

The basic components are shown graphically on Exhibit No. ___ (DLG-1).

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting an natural gas rate increase of $3,457,412 (a 5.9 percent increase over current rates) based on a 2011 test year adjusted for known and measurable changes.

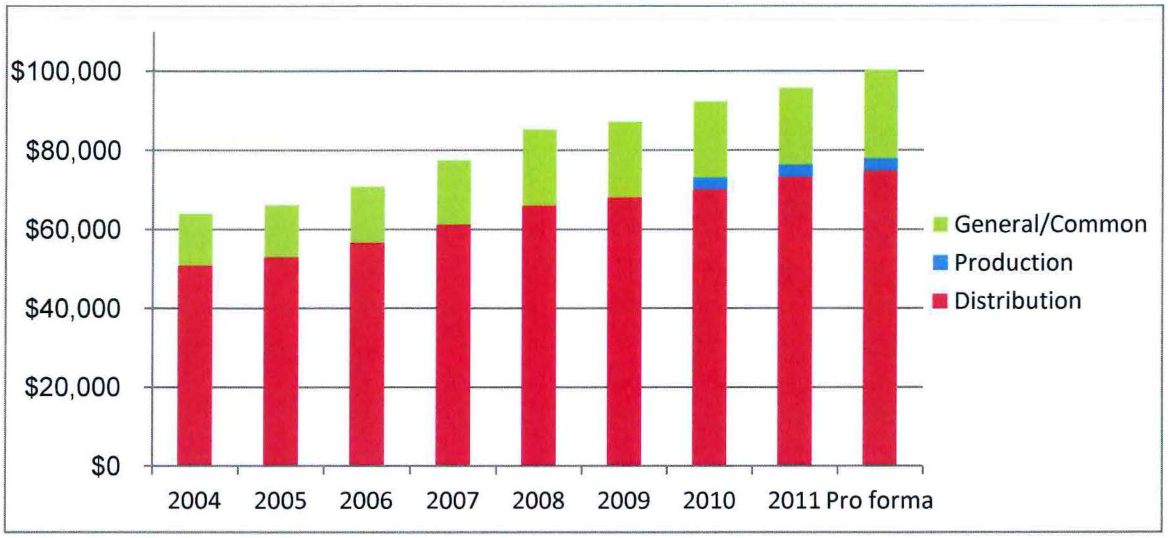
Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows:

Class	Percent Increase
Residential	7.9%
Firm General	2.8%
Small Interruptible	1.4%
Large Interruptible	1.4%
Total	5.9%

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reason for the increase in rates is the increased investment in facilities and the associated depreciation, operation and maintenance expenses and taxes associated with the increase in investment. The table below shows the investment in natural gas plant assigned and allocated to Montana gas operations. The gross investment in Montana gas operations has increased by over $36 million, or approximately 57 percent, from 2004 to the pro forma levels included in this case. In addition to the ongoing investment for new customers and replacing existing facilities, investments in a landfill gas production facility, a new region operations building, and an automated meter reading system have occurred since the last case, along with a new customer billing system to be completed in 2012.



The increase in investment has been accompanied by a growth in customers, but we continue to see conservation by customers. In the last general rate case, Docket No. D2004.4.50, the average annual usage for a residential customer was 94 dk while in 2011, on a weather normalized basis, a residential customer used 86 dk annually.

At the same time, operation and maintenance expenses have decreased on a per customer basis, from an annual cost per customer of $170 per customer in 2004 to an annual pro forma cost of $141 per customer. During this same time period the Consumer Price Index (CPI) increased by 19 percent.

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

A. Montana-Dakota's last general gas rate case in Docket No. D2004.4.50 resulted in an increase of less than 1 percent effective in January 2005.

Q. What is the Company doing to control costs?

A. Montana-Dakota works hard to control its costs by continually looking for opportunities that create efficiencies and control costs. Recently, Montana-Dakota participated in a utility integration effort, along with the three other utilities within the MDU Resources Group, Inc.'s Utility Group (Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company). Through this effort, the four utilities came together to pursue best practices and employ technological advances in an effort to streamline similar processes across all four utilities, while also addressing the current economic uncertainties being experienced today.

Q. What are some of the changes that have been identified to date from this integration effort?

A. A number of changes have already occurred or are in the process of being implemented. Some of the major changes are:

- *Service center consolidation.* We combined five separate call centers operated by Montana-Dakota, Cascade and Intermountain into one service center, located in Meridian, Idaho. This combined center is responsible for all incoming customer calls for the four utilities.
- *Implementation of a central credit center.* A centralized credit center for all four utilities is located in Bismarck, North Dakota, where credit representatives are available to work with customers to resolve credit problems and collection

issues in addition to working with Social Services, the Low Income Energy Assistance Program and other energy assistance agencies. The Bismarck Credit Center will also operate as a back-up call center to the Meridian Customer Service Center during high call times.

- *Establishment of pay stations.* Pay stations were established throughout Montana-Dakota's service territory in an effort to provide convenient bill payment options and extended hours by using established Western Union vendors.
- *Work force reductions.* In addition to the the work force requirements associated with the three changes mentioned above, the Company continues to review all aspects of the utility business to ensure Montana-Dakota is operating as efficiently as possible.
- *Comparable benefits.* The integration of processes brings with it the necessity to have comparable benefits among the utility companies. Primary changes to the benefits structure at Montana-Dakota were in the pension and post retirement areas, which reduced these costs.

All of these measures will provide comparable benefits across the utility group and enable the Company to control its costs.

The Company has also refinanced essentially all of its long term debt since 2006 and has lowered its embedded weighted average debt cost from 8.794 percent at December 31, 2005 to a projected 6.846 percent at December 31, 2012.

Q. Mr. Goodin, what is the compensation philosophy at Montana-Dakota and how does it compare with other like businesses that neighbor Montana-Dakota?

A. Our philosophy is to be able to attract and retain a workforce that can provide safe and reliable service to our customers. We target providing a total compensation package to our employees that is at our market average for similar utility work at other utilities. This compensation includes base pay and incentive pay along with various benefits. Ms. Jones, Director of Human Resources, discusses these areas in more detail.

Q. What return is Montana-Dakota requesting in this case?

A. Montana-Dakota is requesting an overall return of 8.489 percent, inclusive of a return on equity (ROE) of 10.5 percent. Dr. Gaske's analysis indicates that a 10.5 percent ROE is fully justified and supported.

Q. Is Montana-Dakota proposing a weather normalized mechanism in this docket?

A. Yes, the Company is proposing a weather normalization mechanism, referred to as a Distribution Delivery Stabilization Mechanism (DDSM) which Ms. Aberle describes in her testimony. Montana-Dakota is proposing this mechanism to adjust customer bills to reflect the Distribution Delivery Charge component that would have been billed based on normal weather during the winter months defined as November through April. The DDSM proposal along with the requested increase in the fixed charge component of each bill provide an effective means to address the issue of margin volatility while continuing to provide the proper price signal to customers to conserve energy use.

Q. Is Montana-Dakota seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with the Administrative Rules of Montana (ARM) § 38.5.5 Interim Utility Rate Increases. The amount of interim relief sought is $1,686,422 and consists of the Company's investment in facilities and other adjustments included in the pro forma 2011 revenue requirement based on Commission guidelines as described by Ms. Mulkern. The interim increase is necessary to provide the Company an opportunity to recover the investments providing service to customers today.

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

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

- Mr. Jay W. Skabo, Vice President – Operations will testify on the distribution operations and provide support for the distribution investment contributing to the need for the requested increase in rates.

- Mr. Michael J. Gardner, Executive Vice President of Utility Operations Support for Montana-Dakota will testify regarding the customer service function and the new customer billing system.
- Ms. Anne M. Jones, Director – Human Resources, will testify regarding the Total Rewards Philosophy of the Company as it relates to base pay, variable (incentive) pay and employee benefits.
- Mr. Robert C. Morman, Director of Gas Supply for Montana-Dakota will discuss the Billings Landfill gas production project.
- Mr. Garret Senger, Vice President of Regulatory Affairs and Chief Accounting Officer (CAO) for Montana-Dakota, will testify regarding the overall cost of capital, capital structure and overall debt and preferred equity costs.
- Dr. J. Stephen Gaske, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the appropriate cost of common equity for Montana-Dakota's Montana gas operations.
- Ms. Rita A. Mulkern, Director of Regulatory Affairs for Montana-Dakota, will testify regarding the total revenue requirement, the interim revenue requirement necessary for Montana gas operations and proposed recovery of deferred Montana Public Service Commission and Montana Consumer Counsel taxes.
- Mr. Earl Robinson, Principal and Director of AUS Consultants will testify to the Gas and Common Depreciation Studies that support the proposed depreciation rates in this filing.

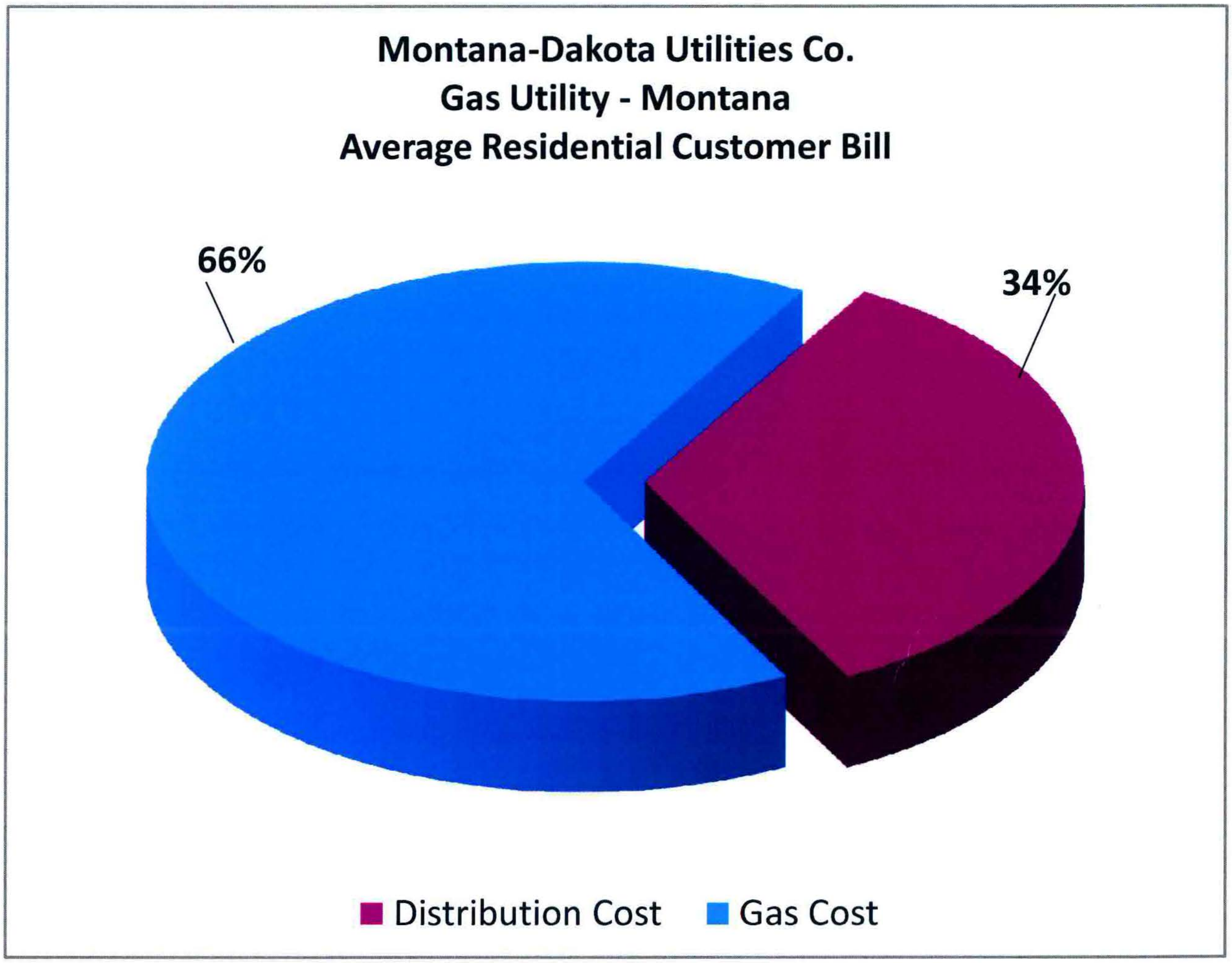
- Ms. Tamie A. Aberle, Director of Regulatory Affairs for Montana-Dakota, will testify on the rate design, the embedded class cost of service study, the marginal gas cost study, the proposed weather normalization mechanism and proposed tariff changes.

Q. Mr. Goodin, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota in providing safe and reliable natural gas service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its Montana natural gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.


Montana-Dakota Utilities Co.
Gas Utility - Montana
Average Residential Customer Bill
66%
34%
Distribution Cost
Gas Cost

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

Before the Public Service Commission of Montana

Docket No. D.2012.9.___

Direct Testimony
of
Jay Skabo

Q. Please state your name and business address.

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

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

A. I am the Vice President - Operations of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc.

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

A. I have executive responsibility for the development, coordination, and implementation of Company strategies and policies relative to all areas of distribution operations.

Q. Please outline your educational and professional background.

A. I hold Bachelor's Degrees in Chemistry from Dickinson State University and Chemical Engineering from the University of North Dakota. My work experience includes three and half years as the Environmental Manager at Montana-Dakota; one and a half years as a Region Manager overseeing gas and electric crews, service technicians, and office personnel in constructing and maintaining our gas and electric systems; and since 2008 in my current capacity. Prior to joining Montana-Dakota, I was the general manager of an industrial waste processing and disposal facility.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of our Montana natural gas operations and our organizational structure. I am sponsoring Exhibit No. ___(JWS-1)

Q. Would you provide a summary of Montana-Dakota's gas operations in Montana?

A. Montana-Dakota provides natural gas service to approximately 78,910 customers in 37 communities, operating over 1,570 miles of distribution mains and approximately 1,040 miles of service lines. The customer base is 89 percent residential customers and 11 percent commercial and industrial customers. As of December 31, 2011, the Company had 136 full and part time employees who live and work throughout our Montana service area. Montana-Dakota's Montana gas service area is divided into two operating regions with regional offices located in Billings, Montana, and Dickinson, North Dakota. In addition to the Billings regional office, there are two other fully staffed operations centers located in the communities of Glendive and Wolf Point. Additionally there are service technicians and construction employees headquartered in 12 other Montana communities deemed strategic to the safe and reliable operation of our distribution system. Service technicians and construction employees in North Dakota, South Dakota and Wyoming also support operations in Montana communities close to the borders of those states. A map of the gas distribution system in Montana is included as Exhibit No. ___(JWS-1).

Montana-Dakota's customers have toll-free access to the Customer Service Center located in Meridian, Idaho, with a backup center in Bismarck, North Dakota, to place routine utility service requests and inquiries from 7:00 am to 7:00 pm local time, Monday through Friday and emergency calls on a 24-hour basis, as discussed in more detail by Mr. Gardner. A Scheduling Center, located in the Meridian, Idaho, facility, transmits electronic service orders to the mobile terminals placed in our fleet of service and construction vehicles. This network allows us to respond quickly to customer requests and emergency situations.

Q. Mr. Skabo, would you explain how Montana-Dakota strives to efficiently provide safe and reliable service to its Montana customers?

A. Certainly. Montana-Dakota has been continually reviewing its field operations for ways to operate more efficiently and has been successful in doing so. Much of this has been possible due to the advancement of cost effective technology, such as Automated Meter Reading (AMR). Montana-Dakota installed AMR technology on both the natural gas and electric meter equipment throughout the four state service area. Montana-Dakota is able to remotely read customers' natural gas and/or electric meters without having to physically visit and read each natural gas and/or electric meter. Additional automated recordkeeping projects include: a new mobile dispatch system called Pragma CAD; a compliance monitoring program called GL Essentials; and Mobile GIS, as discussed in more detail below.

Montana-Dakota has initiated a project to replace the existing computer aided dispatching system for utility service orders. The existing system, Mobile Up, which replaced a paper based system in 1999, has resulted in improved customer service as well as increased operational productivity. Productivity gains achieved with the original system were estimated at 30 percent and the replacement project will ensure that we are able to maintain and improve upon the current level of customer service and operational efficiency gains. By installing this product at all of the companies within the MDU Resources Utility Group, the purchase, installation and ongoing maintenance costs will be reduced by being shared among a larger base.

Montana-Dakota is also in the process of improving its gas operations with the implementation of a compliance software package called GL Essentials. Implementation of this software is to be completed in phases starting this year with plans to be substantially completed by the end of 2013. The overall purpose of this software is to help automate, track, and manage work flow for distribution pipeline operations and to allow for the effective central sharing of the data to the appropriate operations groups to make better evaluations and decisions to enhance public and worker safety around the distribution pipeline systems.

More specifically, this software system automates operations and maintenance work orders that are then electronically dispatched to technicians and the data is returned to the system and stored in a central database. The data that is captured within this system can then be used to enhance and support the existing safety programs at Montana-Dakota such as the Distribution Integrity Management Plan (DIMP), the Transmission Integrity Management Plan (TIMP), the Damage Prevention Program, the Public Awareness Plan, and Emergency Response Procedures. Montana-Dakota has always worked to provide for a safe and reliable natural gas pipeline system. In recent years, the predominant view, by both regulators and utilities, is to enhance data collection and analysis of data in order to further improve safety and reliability. The GL Essentials software and system allows for an effective use of operational data to support operations plans such as TIMP and DIMP.

An additional enhancement that was also put into operation in 2012 is the development and deployment of a mobile mapping system. Montana-Dakota made the change from paper maps to an electronic ESRI GIS based mapping system in 2005. At that time, a very simple map view product was deployed that could look at a snapshot in time of the GIS mapping system. These maps had to be manually updated deployed to the field users periodically. In order to support the larger data needs and effectively support the requirements of new programs like DIMP and TIMP, Montana-Dakota developed and deployed a mobile map product from the 3GIS company. This new mobile map product enhances the Montana-Dakota field mapping in several ways. First, the map updates are now available real time in the field. Second, it gives the field users an ability to mark up the map with critical information such as leak location, damage location, pipe inspection location, or indicate map conflict or errors. Third, it gives the operations group a mechanism to share location information with field workers. Essentially, the addition and deployment of the 3GIS products has allowed for the needed data support for enhancing pipeline safety through the DIMP and TIMP programs.

Pay stations have also been established throughout Montana-Dakota's service territory in an effort to provide convenient bill payment options and extended hours by using established Western Union vendors. Through this arrangement, payments are electronically transmitted to Montana-Dakota, available for viewing by Montana-Dakota personnel within an hour of when the payment is made and posted to customer accounts by the next business day. The number of locations in Montana increased from the five Montana-Dakota offices, to eleven pay station locations. The number of employees handling payments companywide was reduced from approximately thirty five to three. Several pay station locations were added in Billings, as well as locations in Hardin and Laurel, where cashier service was not previously available. In addition, these pay stations are open longer hours and on weekends, providing more and better options for customers who prefer to pay in person. The Company continues to work with established businesses throughout the Company's service territory in order to expand the number of locations at which customers can pay their bills.

The Company continues to review all aspects of the utility business to ensure Montana-Dakota is operating as efficiently as possible.

Q. Has the Company experienced a growth in customers?

From December 31, 2004, at the time of the last general rate case, to December 31, 2011, there has been an increase of approximately 6,040 gas customers, while at the same time a reduction in the distribution expense cost per customer. An examination of the customer growth indicates that the Billings district added 5,455 customers, a 10.3 percent increase in customers, while the Miles City, Glendive and Wolf Point districts saw an increase of 585 customers, an increase of 2.9 percent. Most of the growth in eastern Montana occurred in the last two years, due to growth in the Bakken oil field.

Several factors have allowed us to be much more efficient and allow us to keep O&M costs from increasing, despite inflationary pressures. These factors included the migration to a more "paperless" work environment and the minimization of paperwork handling and order completion; providing customers the option to use pay stations rather than staffing for cashiers and walk-in office traffic; adding Automated Meter Reading; and our Utility Group integration efforts. In 2004, the average distribution O&M cost per customer was $58.50 and in 2011 that cost had dropped to $56.40.

Q. **Has Montana-Dakota made investments in the gas distribution system in Montana, and how have these investments affected the cost of operation and maintenance of the system?**

A. Yes, we have made significant investments into the gas distribution infrastructure as well as investing in the efficiency measures discussed above. The investments in efficiency have contributed to the Company's success in reducing O&M costs per customer from 2004 levels, while the investments in infrastructure allow us to operate the system safely and reliably.

From 2004 to 2008, customer growth was substantial in the Billings area, with many new subdivisions and commercial parks. During this period an average of 185,000 feet of main was installed annually. Approximately 85 percent of this main installation was due to system growth and 15 percent was for replacements for system improvement or relocation of pipe due to other construction. About 1,000 new customers were connected annually during this period. Over $6 million was invested in gas mains during this period for both growth and replacement projects. While the growth related main investment was supported by customer additions and/or customer contributions, the continued decline in natural gas usage per customer as a result of conservation efforts, including improved appliance efficiency, contributes to the need for an increase in rates and revenues to recover the distribution investments.

The growth in the Billings area slowed beginning in 2009. From 2009 through 2011, approximately $1.0 million was spent on main construction projects with about 65 percent of it for replacement projects. Much of the replacement was for city and state road construction projects. During this same period, over $3.3 million was invested in service lines, with 72 percent related to growth. These replacement projects result in improvements to safety and reliability by replacing older pipe with new pipe and by allowing a re-engineering of the system when needed. Those replacement projects were selected based on making improvements to portions of the system deemed to require upgrades. This process includes the implementation of a replacement program in the area of the home explosion in Billings, with the initial portion of the project to be completed in 2012. As discussed later, the process of selecting areas of the system for replacements has become more standardized and data-driven with the implementation of the Distribution Integrity Management Plan.

In Billings, the downtown office and remote warehouse activities (both pre-1950 vintage, some portions dating back to 1912) were replaced with a combined office and operations center for the Rocky Mountain

Region. This has resulted in improved efficiency as management and operations personnel are in a single location resulting in better communications and less time spent traveling between locations. The operations portion of the new facility also provides safer and more efficient working conditions for our employees.

Q. The Pipeline and Hazardous Materials Safety Administration has promulgated a regulation requiring natural gas distribution companies to develop what is known as a Distribution Integrity Management Plan (DIMP). How has Montana-Dakota responded to this regulation?

A. DIMP is a Federal requirement issued as Subpart P of 49 CFR 192 pertaining to all gas distribution system operators. DIMP requires operators to know the make-up of their distribution system. The objective of the plan is to develop a model to assist in determining which areas of the gas distribution system to focus operation, maintenance and repair efforts and resources due to known or predicted threats to the distribution system. The Montana-Dakota plan was implemented on August 1, 2011.

The model assesses eight different threat categories: Corrosion, Natural Forces, Equipment Failure, Excavation, Incorrect Operation, Joint Failure, Outside Force, and Other, all equally weighted.

A detailed geographical information system (GIS) map, with every piece or component that makes up the gas distribution system, both above and below ground, and with as much information about each piece as is available is used as the basis of the model. Scores for various factors were determined by a group of subject matter experts including office engineers, field engineers and field technicians.

The model sets a 50 foot by 50 foot grid to analyze all components. Each grid is then analyzed by eight individual sub-models with up to 150 calculations in each sub-model. This in turn produces a very comprehensive look at the entire system with each component compared equally to the others across the entire four state operating area. In Montana, 351,046 separate components totaling 16,018,757 feet of pipe were analyzed.

The results obtained from the DIMP modeling are consistent with what it was expected to produce by our subject matter experts. The components that score the highest are generally located near district regulator stations where there are concentrations of different components such as fittings and valves, above ground piping, and elevated pressures.

Going forward, the DIMP results will be used as an operational tool to aid in directing resources to reduce pipeline risks. The results will be consistently analyzed to determine accelerated actions to the pipeline so that changes to resource planning and budgeting can be made to carry out the reduction in risks from pipeline threats.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2012.9.___

Direct Testimony
of
Michael J. Gardner

Q. Please state your name and business address.

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

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

A. I am the Executive Vice President of Utility Operations Support for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc.

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

A. I have executive responsibility for the Utility Shared Services Group which certain functions for the four utility companies that are part of MDU Resources Group Inc. (MDU Resources). In addition to Montana-Dakota and Great Plains Natural Gas, the utilities that are part of MDU Resources Group are Cascade Natural Gas Corporation and Intermountain Natural Gas Company. The four utilities, which internally are referred to as the Utility Group, maintain their historical brands to the public, and remain separate subsidiaries or divisions of MDU Resources Group, Inc. The Utility Shared Services Group provides service support functions for the Utility Group including information technology and communications, administrative services, such as purchasing and fleet, engineering and operations procedures, and customer services.

Q. Please outline your educational and professional background.

A. I hold a Bachelor of Sciences in Mechanical Engineering Degree from the University of Washington, as well as a Masters of Business Administration Degree from the same university. I am a Professional Engineer, registered in the state of Washington. I have been in the utility industry for over 20 years, including positions in engineering, field management, safety, training, and operations management. In 2005 I was named Vice President of Operations for Cascade Natural Gas Corporation and in 2008 I was named Executive Vice President and General Manager of Cascade Natural Gas Corporation. I started in my current role in 2009.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Utility Shared Services Group, primarily in the customer services area, including information regarding our customer service model and the measurement of customer satisfaction. I will also discuss our new utility customer information and billing system, or CIS.

Q. Please describe the Utility Operations Support Department.

A. The Utility Operations Support Department (Support Department) was created in early 2009 as part of a package of integration efforts by the Utility Group. The Support Department provides functions such as information technology and customer services to all the companies in the Utility Group. The goals for the Department when providing services, are to share best practices among the companies, enhance the ability to share resources across the companies, provide the services at the best cost, and reduce liability through the implementation of best practices. Services from the Department are allocated to the appropriate company utilizing each service at cost.

Q. Would you please describe the Customer Services Department that is part of Support Services?

A. Montana-Dakota operates a single service center for all inbound communications from customers of all of the Utility Group companies on a 24/7/365 basis. The center is physically located in Meridian, Idaho. Customer service agents are initially trained for one company and eventually many are trained to take calls for more than one company, which increases the efficiency of the center. Customer satisfaction is a high priority. Our internal goal is to answer over 80 percent of all calls in 60 seconds or less. In order to monitor customer satisfaction and ensure we are meeting the needs of customers, we survey our customers, historically through mailed postcards and currently through JD Power and Associates. The Customer Services Department is also responsible for credit and collection activities through a credit center located in Bismarck, North Dakota, as well as all customer programs, such as automated customer information, continuous service, and level pay options. During 2011 customer service enhancements were implemented that benefit our customers. We expanded the hours of standard operation to 7:00 am to 7:00 pm local time. Full service had previously only been available from

8:00 am to 5:00 pm local time. Agents continue to be available 24 hours per day for emergency related calls. We also added an Interactive Voice Response (IVR) system for Montana-Dakota customers. Certain customer service issues, such as bill payment, requesting a copy of the bill, inquiries regarding a due date, or even making payment arrangements, can all be done on a 24/7 basis without the need to talk to a customer service agent. Of course, during normal business hours, the customer can always reach an agent by pressing zero. An automated call-back system was also installed in order to better meet customer demand during times of high call volumes.

Q. What are the service levels for inbound calls at the service center?

A. In 2011, 82.2 percent of all inbound calls were answered in 60 seconds or less. Based on our internal survey results, for 2011, Montana-Dakota customers gave us an overall satisfaction score of 91.8 percent.

The results for the first half of 2012 were similar in that 83.7 percent of all calls were answered in 60 seconds or less. During 2012, the Utility Group started utilizing JD Power and Associates to measure the level of customer satisfaction. Our goal is to be in the top half of all companies surveyed nationally, in terms of overall satisfaction. After the first half of 2012, we were exceeding that goal.

Q. What are some of the factors measured in determining customer satisfaction?

A. One of the reasons we switched to JD Power & Associates for measuring customer service is to be sure we are capturing what is necessary to better measure customer satisfaction and identify what we can do better across all aspects of the operation. The survey questions represent a broad spectrum of customer concerns including billing and payment, price, corporate citizenship, communications, customer service and field service. For example, under billing and payment, drivers include providing a variety of methods to pay the customer's bill, ease of finding the exact amount due, and the usefulness of information on the bill. Under price, drivers include total cost, fairness of pricing, ease of understanding pricing options, and the effort of the utility to help manage monthly usage. Montana-Dakota customers gave particularly good scores, well above the national average, in the area of field customer service and phone customer service, as well as corporate citizenship. Montana-Dakota customers gave scores below the national average on the bill itself and options to pay their bill. Both of these areas will be addressed with our new customer information and billing system.

Q. Montana-Dakota is implementing a new customer information system. Would you please discuss the new customer information and billing system?

A. The system is called Customer Care and Billing (CC&B), and is an Oracle product. It is a top tier Customer Information System, or CIS, and will replace the current CIS system that was implemented in 1999. The core functions of the CC&B system are to store relevant customer information, and based on meter reads, produce accurate billing statements. It is a state of the art system, with newer technology, making it a more configurable product. Once all Utility Group companies are utilizing the system, ongoing costs will be more efficient, including hardware, licensing and maintenance, as the costs will be shared by all Utility Group companies. The new system will also facilitate additional customer interfaces, such as through the internet, and will allow for electronic bill presentment and payment options. As part of the new CIS project Montana-Dakota will also be revamping the consumer bill. For example, the bill will include a graph showing 13 months of historical usage, detailed billing information as well as a summary providing a quick view of the amount due and the due date. These are all items that our customers have told us that they want.

Q. What is the cost of the CC&B system included in this application for new rates?

A. Montana-Dakota's share of the new CC&B system is estimated at $22.6 million, with $4.9 million applicable to Montana gas operations.

Q. When will the new system be implemented?

A. The new CIS will be ready for service by Montana-Dakota by December 31, 2012. However, due to requirements imposed by both the external auditors and internal auditors as part of MDU Resources' Sarbanes–Oxley compliance plan, CC&B will not actually be implemented for billing purposes until February 1, 2013. The requirement is that the conversion to the new system must occur at least three months prior to year-end. Montana-Dakota is currently in the final testing stages to allow for completion by year-end but not in time to convert and go-live with the new system by December 31, 2012.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of Montana
Docket No. D2012.9.__

Direct Testimony
of
Anne M. Jones

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

A. Yes, my name is Anne M. Jones. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Director – Human Resources and Safety for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc.

Q. What are your duties and responsibilities?

A. I am responsible for all disciplines associated with the Human Resources (HR) function including compensation and benefits, organization development and training, labor and employee relations, and compliance with employment and employee relation's laws and practices. I also have oversight of Safety and Technical training functions.

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

A. Yes. I have a Bachelor's Degree in Management with an emphasis in Human Resources from the University of Mary. I began my career with Montana-Dakota 30 years ago and have held a variety of positions of increasing responsibility throughout the Company. I have worked within Human Resources since 1997; and have been Director of Human Resources since 2008.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Total Rewards Philosophy of the Company as it relates to base pay, variable (incentive) pay and employee benefits. It is important for the Company to not only attract talent to its organization, but also to retain the highly skilled talent which it has today.

Q. Would you explain how compensation is reviewed at Montana-Dakota?

A. The first component of the Total Rewards package is base salary. Montana-Dakota's philosophy is to compensate employees at the base salary market average for similar positions, which is consistent or slightly more conservative than most utility organizations. According to the 2010 Watson Wyatt Survey Series which includes companies such as Xcel Energy, NW Natural, Black Hills, and many others, approximately half of the participating organizations strive to provide a total compensation package that is above the market average.

Each year, HR reviews standard benchmark jobs in the corporation such as engineers, construction supervisors and system analysts. It compares the Company's total compensation package for the benchmark jobs to market compensation for comparable positions to insure that the

Company is compensating employees at the appropriate pay grade and range. HR also reviews positions on an "as needed" basis throughout the year to ensure we are competitively compensating within the established pay ranges. The Company uses many reputable industry surveys when determining base pay levels, including the American Gas Association (AGA), Salary.com data, Mercer Benchmark, Milliman, Towers Watson and World at Work, among others.

Q. Would you please discuss the incentive compensation component of the Total Rewards Philosophy?

A. Yes. This second component of the Total Rewards package is incentive pay and Montana-Dakota's incentive plans are a critical portion of total compensation provided to all employees. Incentive compensation is offered in an effort to remain competitive within the industry at the lowest reasonable cost and to focus employee efforts on achieving important objectives. The incentive plans offered encourage continued improvement in standards for performance that lead to positive business results and benefit customers. The key incentive plan measures include financial, customer service and operating costs.

Incentive plans are designed to:

- Establish a strong relationship between pay and Company performance
- Provide focus on Utility strategic initiatives that increase effectiveness and efficiency

- Promote superior customer service
- Deliver labor market competitive rewards that attract, retain and motivate talented employees to higher levels of performance

The efforts of employees, both individually and as team members, are keys to this success. Incentive plans provide an opportunity for employees to receive additional compensation only when pre-established financial results are achieved as well as attainment of important organizational and customer satisfaction goals. Through the design of incentive plans, part of the employees' total compensation package is "at risk." Only when established business performance thresholds are met do employees have the opportunity to receive the incentive pay.

According to a 2012 Towers Watson Regional Incentive Compensation Survey 100 percent of the fifteen participating utilities provided incentive compensation to employees. In the absence of incentive compensation the only viable alternative for Montana-Dakota is to increase base pay to remain competitive in the labor market and retain a qualified work force. Base pay is the most expensive way to compensate employees because other benefits such as the Company's 401K contributions are calculated as a percentage of base salary. Benefit cost increases lead to additional costs for the utility and ultimately for customers. For this reason, it is important to have a reasonable balance of base pay and incentive (variable/at risk) pay to stay competitive in the labor market while controlling costs.

Q. The other component listed was benefits. Would you describe the benefits that are available to employee?

A. Yes. Employee benefits are the third part of the Total Rewards package. The Company offers standard health and welfare plans (medical, dental and vision insurance; vacation and other paid time off benefits; and life, disability and accident insurance); along with a retirement savings plan. Employees share premium costs for many of these benefits.

Q. Has the Company made any recent changes to benefits?

A. Yes. The Company's defined benefit pension plan was closed to new entrants in January of 2006. Additionally, both the non-union (2009) and union (2011) plans have been frozen to significantly reduce future liability and the volatile funding swings which were occurring. There was no change to the pension benefits employees earned as of December 31, 2009 (non-union) and December 31, 2011 (union), but –participants age 65 retirement benefits will remain frozen. The Company now offers a retirement contribution to this group of employees that is age based.

Q. Has the Company made any changes to medical plan benefits?

A. Yes. The medical plans for active employees continue to change to maintain a sustainable benefit under the new healthcare legislation. The Company has restructured and priced the medical benefit plans in a manner that encourages employees to strongly consider a higher deductible medical plan paired with a Health Savings Account (HSA). The migration of employees to a high deductible medical plan encourages employees to be wise consumers of medical services and also will allow employees to build HSA accounts that may be used into retirement. The high deductible plan also decreases the medical liability of the Company under the self-insured plans because first dollar coverage is limited to preventative care.

In 2009, the medical retiree plan was changed to decrease future liability. As of January 1, 2010, retiree medical insurance is no longer offered to employees hired after that date. Employees who attained age 55 by December 31, 2009 are grandfathered and will be required to transition to a retiree reimbursement account (RRA) at age 60. All other employees will only receive the RRA if they retire at age 60 or later.

In 2012, Montana-Dakota implemented another change to reduce post-retirement benefit liability. Medicare eligible retirees that retired after December 31, 1993 are required to move from the Company sponsored retiree medical plan to a Medicare Supplemental Plan. The Company will continue to fund a portion of the retiree's premium through a Health Reimbursement Account.

Q. What other changes have been made to employee benefits?

A. As part of the integration efforts to provide comparable benefits to employees within the Utility Group, Montana-Dakota employees received two additional holidays beginning in 2010. The Company also eliminated the employee discount on the Montana-Dakota utility bill in 2010 for those employees that were active customers as part of its integration efforts.

Q. What benefit does Montana-Dakota's Total Rewards Package provide its Montana gas customers?

A. The Total Rewards philosophy employed by Montana-Dakota is cost effective for the Company and customers because it provides a means to control costs while continuing to attract and retain the work force necessary to provide safe and reliable service to its customers.

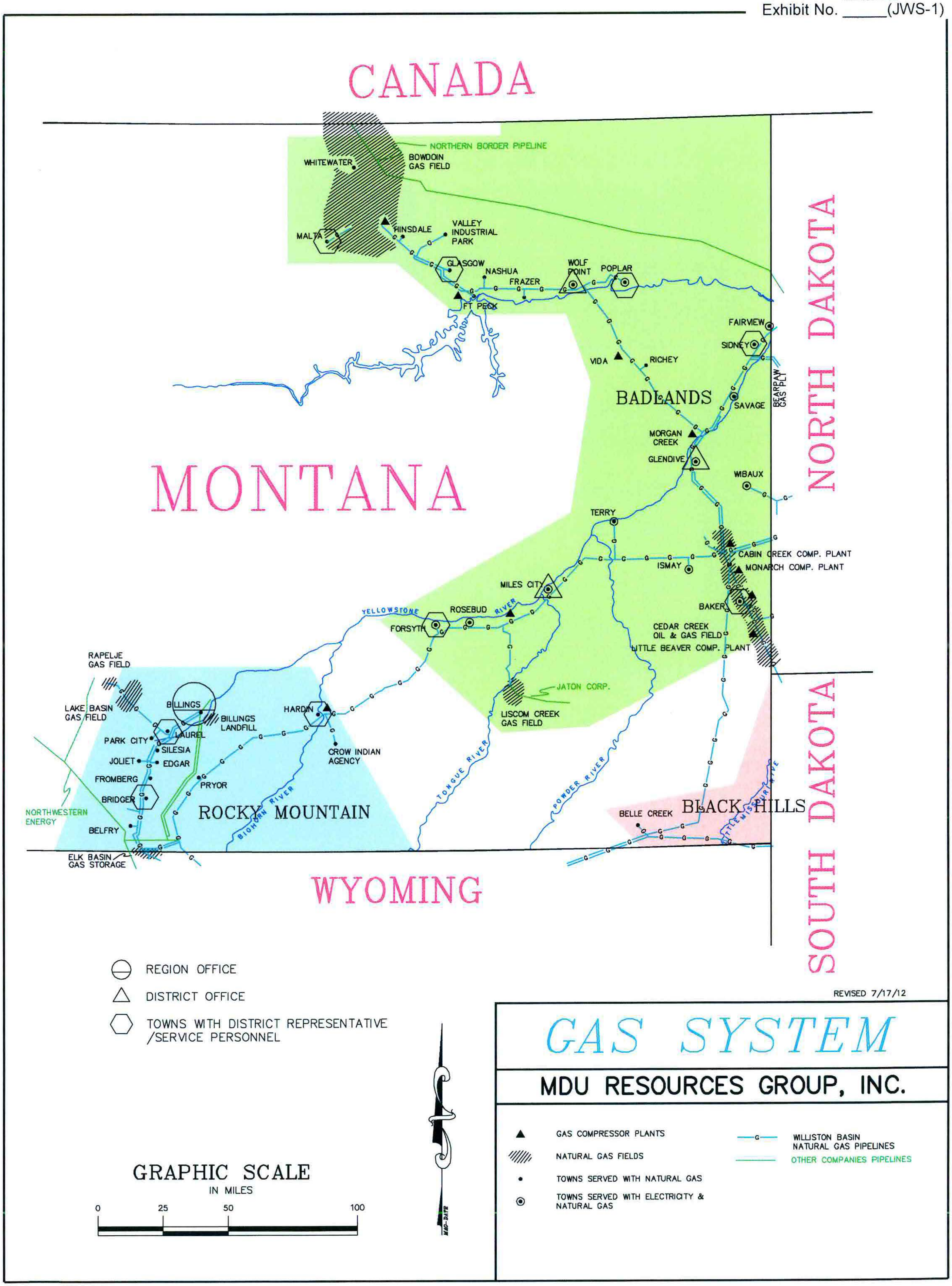
This competitive total reward philosophy is key to maintaining a highly skilled workforce required to operate and maintain the utility. Montana-Dakota's workforce and operations have been significantly impacted by the highly competitive labor market in eastern Montana due to the Bakken oil boom. High paying oilfield jobs are plentiful and our work force is viewed by many companies as a ideal feeder pool for their vacant positions.

It is prudent and of benefit to utility customers to leverage all three components of our Total Rewards Philosophy to minimize turnover. Compensating our employees competitively achieves this objective and in turn helps the distribution system remain safe and keeps operational costs lower.

Q. Does that complete your direct testimony?

A. Yes, it does.

Docket No. _______
Exhibit No. ______(JWS-1)



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

Before the Public Service Commission of Montana

Docket No. D2012.9.___

Direct Testimony
of
Robert C. Morman

Q. Please state your name and business address.

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

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

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

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

A. As Director of Gas Supply, I have oversight responsibility for the day-to-day and long range planning for the purchase of natural gas and obtaining interstate transportation and storage capacity to meet the demand of Montana-Dakota's natural gas customers.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting and Business Administration from the University of Mary. My work experience includes eighteen years of experience with Williston Basin Interstate Pipeline

Company, now WBI Energy Transmission, in areas of operations, measurement accounting and gas control. I also have twelve years of experience with Montana Dakota in the measurement and gas supply departments. For the past eight years I have been the Manager/Director of Gas Supply.

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

A. The purpose of my testimony is to describe the Billings Landfill methane gas production facility and how it fits in with Montana-Dakota's overall gas supply portfolio.

Q. Would you describe the development of the Billings Landfill project?

A. Montana-Dakota was approached by Wenck Engineering (Wenck) to determine if there was interest in partnering in a project(s) capable of capturing methane gas from landfills located in Montana-Dakota's service territory. Methane gas is produced in landfills, along with carbon dioxide (CO_2) and other gases, as the garbage breaks down once it is covered. The amount of methane produced varies with each landfill dependent on the age of the landfill, the makeup of the garbage as well as the moisture content of the garbage. Depending on the amount of methane produced from a landfill, it may be required to capture and destroy the methane according to Environmental Protection Agency (EPA) regulatory requirements. The Billings Landfill has been studied and does not currently require methane capture. Landfills throughout the U.S. have conducted reviews accordingly to environmental regulations and if they are not required to capture and destroy methane, they may choose to capture the methane voluntarily. The cities of Billings, Montana and Rapid City, South Dakota were approached by Montana-Dakota to gauge the interest in pursuing such a project because of the size, age and future expansion of their respective landfills.

When Montana-Dakota approached the City of Billings to gauge its interest in partnering with Montana-Dakota to develop its landfill methane, the City confirmed that methane capture was not required. However, it was determined that a gas production facility solution would serve both the City and Montana-Dakota well as the landfill gases would be captured and destroyed and Montana-Dakota would be able to extract the methane and use the gas to generate electricity, direct the raw methane gas to an end user for consumption in a boiler or dryer, or condition the gas to pipeline quality gas where it could be injected into a distribution system for customer use.

Montana-Dakota worked with Wenck Engineering, who had experience in the development of landfill methane, and researched the different methods to capture and produce methane gas from the landfill. There were no industrial or commercial facilities near the Billings landfill to utilize a direct burn of the raw gas in a boiler, dryer or other commercial usage. During the time of the evaluation, the commodity cost of natural gas was in excess of $6.00 and the monthly index price at Henry Hub had averaged approximately $7.45 for the previous five years. As a result of the past high prices and apparent continuation of such pricing, Montana-Dakota explored the option of conditioning the landfill methane and using the resultant pipeline quality gas in the gas distribution system where it would be blended with natural gas and consumed by sales customers. A series of wells were drilled and flow tested to determine the amount of gas in the landfill and the results indicated adequate gas was present to pursue a project.

Montana-Dakota and Wenck personnel visited a molecular gate facility to gain a better understanding of the process to condition the gas to a pipeline quality product. It was determined that the process was legitimate and a study was completed to determine the cost effectiveness of moving forward with this project.

Q. How did you determine that the project was beneficial to customers?

At the time the project was studied in 2008-2009, the monthly commodity price of natural gas had reached highs in excess of $10 per dkt and there were concerns nationally and in our region of long term natural gas supply and price volatility. The Henry Hub twelve month average index cost of gas in 2008 was $9.04 with the monthly indexes ranging from a low of $6.47 to a high of $13.11. The Billings landfill project was determined to be a long term supply of natural gas as the facility is a regional landfill and would continue to receive garbage for the next 40-50 years. As the landfill increases in size and additional collection wells are installed, the molecular gate facility would be able to expand to capture the methane as it is produced. The studies indicated the gas could initially be developed for around $6 per dkt and the cost of production would decrease as the size of the landfill grew and produced more methane and efficiencies of scale were realized. The supply of methane gas from the landfill would be at a cost that would reduce exposure to the volatile price swings we were seeing throughout the United States. It would serve as a physical hedge as the price would remain relatively stable and known.

Because of the volatility of natural gas prices, Montana-Dakota did not complete a detailed study for the use of methane for power generation although a portion of the lower BTU tailgas from the molecular gate facility is used to generate electricity which supplies power to the site.

In addition to being a benefit to Montana-Dakota's natural gas customers, the City of Billings also benefits from the installation of the landfill facility. We entered into a long term agreement with the City of Billings to capture and produce the methane which makes this an environmentally friendly project. Montana-Dakota reimburses the City of Billings an amount similar to a royalty payment for the amount of natural gas that is delivered to natural gas customers.

Montana-Dakota is also identifying the value of carbon credits, environmental attributes and/or renewable energy credits that are associated with this facility. By capturing the greenhouse gases that are naturally emitted from the landfill, the Company may be able to market these credits or attributes and obtain a monetary value that will be shared by Montana-Dakota's customers and the City of Billings.

Q. Would you describe the current operations at the landfill production site?

A. Yes. The facility commenced producing methane gas in December 2010 and approximately 129,200 dkt of gas were extracted from the landfill and delivered into Montana-Dakota's distribution system for use by its sales customers in 2011. There are currently one and one-half full time equivalent employees assigned to operate the plant. Initially, 63 wells were drilled and gas is currently being extracted from these wells. In June of 2012 Montana-Dakota installed additional piping in the area of the landfill that is currently receiving garbage and began drawing methane in August from this new area. As more cover is added to this new section Montana-Dakota will draw additional methane which will increase the throughput and efficiency of the methane recovery facility. To date Montana-Dakota has invested approximately $11 million in the facility.

The production facility, as well as the gas from the facility are considered part of Montana-Dakota's integrated system and as such, are allocated to the four jurisdictions that make up the integrated gas system.

Q. How does the gas from the Billings landfill fit into the gas supply portfolio?

A. As noted above, the Billings landfill currently produces approximately 130,000 dk annually, which represents 0.5 percent of

Montana-Dakota's total system requirements. As additional phases of the landfill are developed Montana-Dakota expects the production to provide 1.5 – 2.0 percent of total system requirements. The addition of the Billings landfill provides supply diversity, a cost competitive gas supply, and an environmentally friendly fuel source.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of Montana

Docket No. D2012.9.___

Direct Testimony
of
Garret Senger

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

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

Q. Would you please describe your duties?

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

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

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and a Masters in Business Administration. I started my career with Montana-Dakota in 1985 as a financial analyst in the Financial Reporting area and during my tenure with the Company have held positions of increasing responsibility, including Supervisor of Financial Reporting, Manager of Financial Forecasting, Manager of Financial Reporting & Planning, Director of Accounting and Controller, and Chief Accounting Officer.

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

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

Q. Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing natural gas distribution service?

A. Yes, I am.

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

A. I am responsible for presenting Statement A, Statement B, and Statement F and Interim Statements A and B of Montana-Dakota's rate increase application.

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

A. Yes, they were.

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

A. Yes, they are.

Q. Would you describe Statement A and Statement B?

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2011 with June 30, 2012 information on pages 3 and 4, and the notes to the financial statements following.

Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2011 and six months ended June 30, 2012.

Statements A and B have been prepared from the Company's books and records which are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you generally describe Statement F?

A. Statement F shows the average utility capital structure of Montana-Dakota for the twelve months ended December 31, 2011 and the projected average capital structure for 2012. Statement F includes the associated costs of debt, preferred stock and common equity. The capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 8.489 percent. The cost of debt and preferred stock were derived from Montana-Dakota's books and records. The 10.5 percent cost of common equity contained within the overall cost of capital is supported by the testimony of Dr. J. Stephen Gaske.

Statement F, Rule 38.5.146 summarizes the actual average utility capital structure at December 31, 2011 and the projected average capital structure and related utility costs of capital for 2012. As shown on page 1, the components of the 2012 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Capital Ratio	Cost	Weighted Cost of Capital
Long Term Debt	39.691%	6.846%	2.717%
Short Term Debt	4.750%	1.399%	.066%
Preferred Stock	2.172%	4.583%	.100%
Common Equity	53.387%	10.50%	5.606%
Required Rate of Return	100.000%		8.489%

Page 2 of Rule 38.5.146 reflects the Company's utility common equity balance at December 31, 2011 and the projected balance at December 31, 2012. The changes to the common equity balances are representative of normal changes, including projected earnings and equity additions less dividends.

The debt costs reflected on Statement F, Rule 38.5.147, page 1 represent the actual weighted embedded costs of Montana-Dakota's long-term debt at December 31, 2011 and the long-term debt projected to be outstanding at December 31, 2012, and are supported by pages 2 through 4. In calculating the debt costs, the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Rule 38.5.147, pages 2 and 3. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions. Page 4 reflects the amortization of issuance costs associated with reacquired debt.

Page 5 of Statement F, Rule 38.5.147 reports the actual average short-term debt balance and cost of short-term debt for 2011 as well as the projected average short-term debt balance and the associated interest expense and cost of short-term debt for 2012.

Statement F, Rule 38.5.148, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2011 and projected cost of the issues to be outstanding at December 31, 2012.

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

A. Through its financial planning process the Company determines the amounts of necessary capital and financing required to support the capital investments to meet its obligation to provide safe, adequate and reliable service to its customers as well as its ongoing working capital requirements for operating and facility maintenance. Montana-Dakota finances its operations targeting a year end 50/50 debt to equity ratio capital structure. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of its short-term credit line and the issuance of additional long-term debt and equity financing as required to maintain its targeted capital ratios while meeting the finance needs of its combined utility operations. In 2008, through a private placement, the Company issued $100 million of ten year unsecured senior notes at an interest rate of 6.04 percent. In 2009 the Company obtained $29 million of common equity through new stock issuances between July and October. In 2009 the Company issued $50 million of unsecured senior notes in two $25 million private placements with a seven year maturity, at interest rates of 6.66 percent and 6.61 percent respectively.

Since 2006, the Company has refinanced essentially all of its long-term debt and has lowered its embedded weighted average debt cost from 8.794 percent at December 31, 2005 to a projected 6.846 percent at December 31, 2012. The Company's mix of securities employs various maturity dates to provide flexibility and mitigate refinancing risks. The Company does not plan to issue additional long-term debt prior to December 31, 2012 but anticipates adding $25 million of common equity in late 2012, again to achieve and maintain the targeted 50/50 year end capital structure at December 31, 2012.

Q. What does Statement F, Rule 38.5.147 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2011 and the associated cost of long-term debt, and it shows the projected long-term debt and associated costs for 2012 as well as the average cost of debt for the two periods. Page 2 shows the cost and long-term debt balance by issue at December 31, 2011 and page 3 shows the projected long-term debt balance and cost at December 31, 2012. Page 4 reflects the amortization of issuance costs associated with reacquired debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues, the same calculation as is used by the Company for accounting purposes.

Q. Would you please describe Statement F, Rule 38.5.147, page 5?

A. Page 5 presents the projected average short-term debt balance for 2012 as well as the projected average cost of short-term debt. A twelve month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve month average calculation is more reflective of the borrowing level than a beginning and end of year average balance.

Q. What does Statement F, Rule 38.5.148 show?

A. Page 1 presents the preferred stock balances at December 31, 2011 and the projected balances for December 31, 2012. The anticipated weighted cost of preferred stock is also shown on page 1. Page 2 sets forth the various preferred stock issues outstanding at December 31, 2011 and page 3 sets forth the issues projected to be outstanding at December 31, 2012.

Q. What does Statement F, Rule 38.5.149 show?

A. The schedule shows the issuances of shares of common stock for the five-year period ending December 31, 2011.

Q. What does Statement F, Rule 38.5.150 show?

A. Page 1 indicates that MDU Resources Group, Inc. did not issue shares in connection with a stock split or stock dividend during the five year period from 2007 through 2011.

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

A. This schedule presents various financial and market data relative to the Company's common stock for the years 2007 through 2011, and for each month of the twelve month period ended December 31, 2011.

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

A. This schedule shows the reacquisition activity for long-term debt in the last five years and shows a summary of scheduled retirements of preferred stock for the five years ended December 31, 2011.

Q. Montana-Dakota is proposing new depreciation rates in this filing, based on plant for the twelve months ending December 31, 2008, and supported by Mr. Earl Robinson in his testimony. Has Montana-Dakota implemented the new depreciation rates developed by Mr. Robinson?

A. The new rates were implemented effective January 2010 based on the referenced study, with the exception of the cost of removal rates on distribution plant. Montana-Dakota implemented the new rates because overall, absent the cost of removal rates on distribution plant, the study resulted in lower depreciation rates. Montana-Dakota made the decision to implement the lower rates and elected to use the cost of removal on distribution rates that were in effect at the time until the new depreciation study could be reviewed in a general rate case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

Docket No. 2012._.____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

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

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

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

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986, I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986, I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986, I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988, I returned to H. Zinder & Associates ("HZA") and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors ("Concentric") and I became a Senior Vice President of Concentric.

Q3. Have you presented expert testimony in other proceedings?

A. Yes. I have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before 11 state and provincial regulatory bodies, including the Montana Public Service Commission. I also have testified or filed testimony or affidavits before various federal regulators, including the Federal Energy Regulatory Commission on more than thirty occasions, the National Energy Board of Canada, and the Comisión Reguladora de Energia de México ("CRE"). Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, the New Brunswick Energy and Utilities Board and seven state public utility

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

I. INTRODUCTION

A. Scope and Overview

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

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to estimate the cost of common equity capital for the Company's natural gas distribution operations in the state of Montana. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's Montana natural gas distribution operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's Montana natural gas distribution operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

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

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

Table 1: Requested Rate of Return – Montana Gas Operations

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$280,485.10	39.691%	6.846%	2.717%
Short Term Debt	$ 33,568.45	4.750%	1.399%	0.066%
Preferred Stock	$ 15,350.00	2.172%	4.583%	0.100%
Common Equity	$377,270.92	53.387%	10.50%	5.606%
TOTAL	$706,674.47	100.000%		8.489%

As my testimony discusses, an overall allowed rate of return of 8.489 percent, with a 10.50 percent return on common equity, represents the cost of capital for Montana-Dakota at this time.

B. <u>Company Background</u>

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

A. Montana-Dakota is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in the generation, transmission and distribution of electricity, and the distribution of natural gas, in the states of North Dakota, Montana, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural Gas Co., which distributes natural gas in the states of Washington and Oregon; Intermountain Gas Company, which distributes natural gas in the state of Idaho; and Great Plains Natural Gas Co., which distributes natural gas in southeastern North Dakota and western Minnesota. Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction, natural gas and oil exploration and production, natural gas gathering and transmission, and produces and markets aggregates and other construction materials.

In 2011, the utility companies within MDU Resources provided natural gas distribution service to 846,000 residential, commercial and industrial customers in 334 communities across eight states.[1] In addition, Montana-Dakota provided electric utility service to over 127,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas across four states.[2] Gas distribution assets comprised 25.6[3] percent of MDU Resources' total assets in 2011, and gas distribution revenues comprised 22.4[4] percent of total operating revenues. In addition, gas distribution operating income accounted for 20.4[5] percent of MDU Resources' total operating income in 2011. Montana accounted for 8 percent of the gas distribution operating revenues, while Idaho (33 percent), Washington (26 percent), North Dakota (12 percent), Oregon (9 percent), South Dakota (6 percent), Minnesota (4 percent), and Wyoming (2 percent) accounted for the other 92 percent of gas distribution operating revenues.[6]

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[1] MDU Resources Group, Inc., 2011 SEC Form 10-K, at 9.
[2] Ibid, at 6.
[3] Ibid, at 82.
[4] Ibid, at 80.
[5] Ibid, at 80.
[6] Ibid, at 9.

Q7. Would you please describe Montana-Dakota's Montana gas service territory?

A. Montana-Dakota provides natural gas distribution service to approximately 76,000 customers in 36 communities in eastern Montana, including the cities of Billings, Glendive and Miles City, and many small towns and rural areas. The economy of eastern Montana is primarily based on ranching, wheat farming, oil and coal. From an economic perspective, the rural nature of eastern Montana poses accessibility challenges, resulting in less access to markets and high transportation costs to larger markets. In addition, rural county residents lack access to the same variety of goods and services available in more populated areas.

Montana-Dakota's Montana natural gas operations have experienced slight growth in recent years as a slowly growing customer base has been offset by declining average use per customer due to energy efficiency and conservation. Most of the recent investment in this jurisdiction has been for replacement of aging facilities and installation of automated meter reading ("AMR") and customer billing systems. Significant investment will continue to be required in coming years to replace aging plant so that the Company can continue to provide safe, reliable and efficient natural gas distribution service to its Montana customers.

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

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

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia (262 U.S. 679, 693 (1923))*, the Court indicated that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;

2. sufficient to maintain the financial integrity of the regulated company; and,

3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

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

A. The same standards should apply. When an unregulated entity faces competition, the pressure of that competition and consumer choices will combine to determine the fair rate of return. However, when regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, both the consumer and the public interest depend on establishing a return that will readily attract capital without being excessive.

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

A. For purposes of setting regulated rates, the current, embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q11. How is the cost of common equity determined?

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

B. Interest Rates and the Economy

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

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. Real growth in the Gross Domestic Product ("GDP") has averaged 2.7 percent annually during the past 30 years, 2.6 percent for the past 20 years and 1.6 percent for the past 10 years. Economic growth remained sluggish in the first quarter of 2012, with real GDP increasing at an annual rate of 2.0 percent, as the economy continues to slowly recover from the 2008-09 recession. According to Blue Chip Economic Indicators, the consensus forecast for expected growth in real GDP is

2.6 percent in 2013 and 3.0 percent in 2014, respectively.[7] Likewise, the U.S. unemployment rate has improved slightly in recent months to 8.2[8] percent as of July 2012, but remains at unusually high levels after the recession. In light of these weak economic conditions, the Federal Reserve has maintained its discount rate of 0-0.25 percent for overnight loans to banks in order to provide continued liquidity to the U.S. financial markets.

As Pages 2-4 of Schedule 1 of Exhibit No. ___(JSG-2) show, interest rates on longer-term, public utility bonds have declined substantially since the first half of 2011, with average 2012 yields on A-rated public utility bonds at approximately 4.31 percent and yields on Baa-rated public utility bonds at approximately 5.03 percent. Although current credit spreads remain lower than during the peak of the global economic crisis in late 2008 and the first half of 2009, they are significantly higher than before the financial crisis. Many market experts have attributed these increased credit spreads to the "flight to safety" which began in the aftermath of the global economic crisis that commenced in the 3rd quarter of 2008 with the failure of many borrowers to make payments on sub-prime mortgages. The concept of the "flight to safety" is that risk-averse investors flock to the least risky government-backed securities, lowering the yield on those securities, but significantly increasing the capital costs associated with the more risky corporate securities.

7 Blue Chip Economic Indicators, Volume 37, No. 3, March 2012, at 3 and 14.
8 Source: Bureau of Labor Statistics, July 6, 2012 release.

Investors also are influenced by both the historical and projected level of inflation. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.4 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.3 percent. According to Blue Chip Economic Indicators, the Consumer Price Index is forecasted to increase by 2.2 percent and 2.4 percent for 2013 and 2014, respectively.[9] Over the intermediate and longer-term, however, investors can expect higher inflation rates as the Federal Reserve's accommodative monetary policy since 2008 places upward pressure on consumer and producer prices once economic growth returns to historical levels. According to Blue Chip Financial Forecasts, the projected yield on 30-year Treasury bonds from 2014-2018 is 5.1 percent and from 2019-2023 it is 5.5 percent.[10] These interest rates are significantly higher than the current yield on the 30-year Treasury bond, suggesting that investors expect a substantial increase in inflationary pressure over the intermediate and long-term periods.

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

A. Although corporate bond yields are lower than pre-crisis levels, credit spreads have increased in the past year, especially for intermediate quality corporate bonds, as investors remain risk averse. The equity markets generally have not fully recovered from the large stock market decline in 2008-2009, and have remained volatile as compared to historical measures. This suggests that the cost

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9 Blue Chip Economic Indicators, Vol. 35, No. 3, March 10, 2010, at 3 and 14.

10 Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

of common equity generally is higher than it was before the significant risks of equity investment were emphasized during the recent market downturn.

C. Discounted Cash Flow ("DCF") Method

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

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

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

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

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D_0 (1 + .625g)}{P} + g \qquad (1)$$

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

P = the current market price of the stock;

D_0= the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

D. Flotation Cost Adjustment

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

A. Yes. There are significant costs associated with issuing new common equity capital, and these costs must be considered in determining the cost of capital. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 44 new common stock issues by natural gas distribution companies from January 2000 to June 2012. Flotation costs associated with these new issues averaged 3.81 percent.

This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 4.0 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.04.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

E. DCF Study of Natural Gas Utility Companies

Q17. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity for its Montana natural gas distribution operations?

A. Because Montana-Dakota's Montana natural gas distribution business must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's natural gas distribution operations as a stand-alone company is not possible. As an alternative, I have used a group of natural gas distribution companies that have publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for Montana-Dakota's Montana natural gas distribution operations.

Q18. How did you select a group of natural gas distribution proxy companies?

A. I started with the eleven companies that Value Line classifies as Natural Gas Distribution Companies to ensure that the company is considered to be primarily engaged in the natural gas distribution business and that retention growth rates are available. From that group, I eliminated any companies that did not have investment-grade bond ratings from either Standard & Poor's ("S&P") or Moody's Investors Service ("Moody's) because such companies are not sufficiently comparable in terms of business and financial risk to Montana-Dakota. In addition, I excluded any companies that did not pay dividends or that did not have future growth rate estimates provided by both Value Line and Zack's. In order to ensure that the company is primarily engaged in the natural gas distribution business, I eliminated any company that did not derive at least 70 percent of its operating income from regulated natural gas distribution operations in 2011, and that did not have at least 70 percent of its total assets devoted to the provision of natural gas distribution service in 2011. As shown on Exhibit No. ___(JSG-2), page 1 of Schedule 2, eight companies met these criteria for inclusion in the proxy group.

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

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation, I used the average of the high and low stock prices for each company during the six month period from January 2012 through June 2012. 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. These dividend yields were then multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the projected dividend yield component of the DCF model.

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

A. I developed three different DCF analyses of the proxy companies based on three different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach, I calculated retention growth (also known as "sustainable growth") forecasts from Value Line forecasts of dividends, earnings, and returns on equity to derive the DCF rate of return estimate. As a second approach, I conducted a Basic DCF analysis that relied on analysts' earnings forecasts for the growth rate component of the model. My third approach uses a combination of the Value Line retention growth forecasts and analysts' earnings growth projections to produce a Blended Growth Rate Analysis.

F. Retention Growth Analysis

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

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

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

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

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

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that is generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) by the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

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

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected to occur several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that is being retained and reinvested in the company. This earnings retention rate is multiplied by the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 5.44 percent.

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

A. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied by the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the Retention Growth DCF estimate of the cost of common equity capital for the proxy companies. The Retention Growth DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.64 percent to 11.48 percent. In this analysis, the median for the group is 9.16 percent and the third quartile is 11.18 percent.

G. Basic DCF Analysis

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

A. In my Basic DCF analysis, I have estimated expected future growth based on long-term earnings per share growth rate forecasts of investment analysts, which are an important source of information regarding investors' growth rate expectations. This Basic DCF analysis assumes that the analysts' earnings growth forecasts incorporate all information required to estimate a long-term expected growth rate for a company. Zack's is a service that collects earnings growth estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the primary source for analysts' forecasts in my calculations. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term earnings growth rate estimates for the natural gas distribution proxy companies is 4.42 percent.

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

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied by the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.39 percent to 9.62 percent. In this analysis, the median for the group is 8.78 percent and the third quartile is 9.40 percent.

H. Blended Growth Rate Analysis

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

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

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

A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG-2), I calculated a weighted average of the analysts' projected earnings growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a one-half weighting to the analysts' earnings growth rate projections and one-half weighting to the projected retention growth rates. In the current environment, this weighting reflects my view that analysts' earnings growth forecasts may tend to understate long-term sustainable growth rates at this time, and that projected retention growth rates are as valid as analysts' growth rates because they reflect investor expectations with regard to future inflation and capital investment. The average of the blended growth rates for the proxy companies is 4.93 percent and the median is 4.92 percent.

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

A. These calculations are shown on page 8 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield for each company is multiplied by the quarterly dividend adjustment factor (1 + .625g), and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the cost of common equity capital for the proxy companies. This Blended Growth Rate Analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 8.23 percent and 10.55 percent. In this analysis, the median for the group is 8.91 percent and the third quartile is 9.58 percent.

I. <u>Risk Premium Analysis</u>

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

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual return on large company common stocks has exceeded the return on long-term corporate bonds by a premium of 540 basis points (5.4 percent) per year from 1926-2011.[11] When this premium is added to the average yield on Moody's corporate bonds for the period from January 2012 through June 2012 of 4.41 percent, the result is an investor return requirement for large company stocks of approximately 9.8 percent. However, investors in smaller companies expect higher returns over the long term, due to the additional business and financial risks that smaller companies face. According to Ibbotson Associates, companies in the same size range as Montana-Dakota's Montana natural gas

[11] 2012 Ibbotson Valuation Yearbook, pg 23. Calculation: (11.8 percent – 6.4 percent = 5.4 percent).

distribution operations have had a premium of 1,420 basis points (14.2 percent) over the average returns on long-term corporate bonds.[12] When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 18.6 percent. This analysis indicates that the rate of return that I am proposing in this proceeding would be low relative to the historic risk premiums earned by similarly-sized unregulated companies.

J. Relative Risk Analysis

Q32. Have you compared the risks faced by Montana-Dakota's Montana natural gas distribution operations with the risks faced by the proxy group of companies?

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

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q33. Please describe the business risks inherent in the natural gas distribution industry.

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived natural gas distribution assets, for which cost recovery occurs over a period of thirty years or more, are subject to

[12] 2012 Ibbotson Valuation Yearbook, pgs 23, 88 and 202. Calculation: (20.6 percent – 6.4 percent = 14.2 percent.)

enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

Q34. What are some of the business risks faced by Montana-Dakota's Montana natural gas distribution operations?

A. The Company's natural gas distribution operations in Montana face many of the same business risks that are associated with other natural gas distribution companies. However, Montana-Dakota's Montana gas distribution operations face some particular risks that distinguish the Company from the proxy group of distribution companies, including: (1) being substantially smaller than the proxy group companies; (2) providing service in a territory with a relatively undiversified local economy; and (3) recovering a substantial portion of its fixed costs through volumetric rates with no protection against persistent declines in customer usage due to energy efficiency and conservation efforts.

As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's Montana natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's Montana natural gas distribution assets are equal to only 1.4 percent of the assets of the median proxy company. Similarly, Montana-Dakota's Montana natural gas distribution operating revenues and operating income are only 4.3 percent and 2.9 percent of the level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 24 and 70 times the size of Montana-Dakota's Montana natural gas distribution operations.

Montana-Dakota's relatively small natural gas distribution operations in Montana are heavily dependent upon an undiversified local economy. With its small revenue base, Montana-Dakota's Montana natural gas distribution operations are subject to slightly greater risk that a major employer or industry, such as oil and gas production, or an oil refinery, might experience a downturn that would significantly affect demand for natural gas distribution in the service territory. The Company's smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies.

Another risk faced by Montana-Dakota's Montana natural gas distribution operations is the fact that the Company recovers a substantial portion of its fixed costs through the volumetric component of rates and does not have a revenue decoupling mechanism in Montana. In contrast, as shown on Exhibit __(JSG-2), Schedule 4, 65.3 percent of the customers served by the proxy companies are located in jurisdictions that have revenue decoupling mechanisms that better allow their rate designs to reflect the fixed cost nature of their operations. As a result, these companies have less risk than Montana-Dakota's Montana natural gas distribution business that persistent reductions in volume per customer will affect their ability to recover fixed costs. For example, even with the proposed increase in the residential customer charge and a weather-normalization clause, a significant portion of fixed costs will still be recovered on a usage basis. Unlike random variations in usage from year to year that tend to average out, a persistent decline in volume per customer does not provide symmetrical upside and downside risks. Instead, this phenomenon poses a risk of chronic under-recovery of costs, especially the return on common equity.

Considering only its smaller size, Montana-Dakota's Montana natural gas distribution operations might require a return that is more than 100 basis points higher than the return required for the typical proxy company. Additionally, there is a significant need for capital expenditures in Montana-Dakota's Montana natural gas distribution operations even as average use per customer has been declining. Furthermore, Montana-Dakota's Montana natural gas distribution business also generally faces above-average rate design risk relative to the proxy group. In summary, Montana-Dakota's Montana natural gas distribution operations are riskier than the operations of the proxy companies.

Q35. What are the regulatory risks faced by Montana-Dakota's Montana gas utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on natural gas distribution companies is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of natural gas distribution companies to finance their operations. Thus, in some instances, regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the natural gas distribution industry.

The regulatory environment can significantly affect both the access to, and cost of capital in several ways. As noted by Moody's, "the predictability and supportiveness of the regulatory framework in which a regulated utility operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[13] Moody's further noted that:

> For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that

13 Moody's Global Infrastructure Finance, *Regulated Electric and Gas Utilities*, August 2009, at 6.

> exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor.[14]

Regulatory Research Associates ("RRA") describes the regulatory climate in Montana as being "somewhat restrictive from an investment perspective".[15] Consequently, equity investors require somewhat higher allowed returns in order to compensate for this higher regulatory risk, so that Montana-Dakota's Montana natural gas distribution operations can compete for capital at reasonable terms and conditions.

Q36. Would you please describe Montana-Dakota's relative financial risks?

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota, as a division of MDU Resources, does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the credit ratings assigned by S&P

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14 *Ibid.*

15 Source: Regulatory Research Associates, Montana State Commission Profile, accessed June 22, 2012.

and Moody's to each of the companies in the comparison group and MDU Resources.[16]

The median S&P bond rating for companies in the proxy group is A-. By comparison, MDU Resources' senior, unsecured debt carries an S&P rating of BBB+. This suggests that the perceived business and financial risk of MDU Resources' bonds is slightly higher than that of the typical company in the comparison group.

The capital structure data on Schedule 2, page 9, in Exhibit No. ___ (JSG-2) show that Montana-Dakota's filed common equity ratio of 53.4 percent is somewhat greater than the 49.7 percent median for the proxy companies as of March 31, 2012. This above-average common equity ratio, which is offset somewhat by the Company's below-average bond rating, suggests slightly below-average financial risk for Montana-Dakota's Montana natural gas distribution operations.

Q37. Would you please describe Montana-Dakota's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Overall, the market risk of Montana-Dakota's Montana natural gas distribution business is comparable to that of the companies in the natural gas distribution comparison group.

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[16] Moody's withdrew its credit rating for MDU Resources on April 7, 2011.

Q38. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's Montana natural gas distribution operations?

A. Montana-Dakota's Montana natural gas distribution operations face overall risks that are near the top of the range relative to those of the proxy companies. Although it has financial risks that are slightly below average relative to the proxy companies, Montana-Dakota's Montana natural gas distribution operations have business risks that are above average. In addition to its exceptionally small size relative to the proxy companies, and its exposure to a relatively undiversified local economy, Montana-Dakota's Montana natural gas distribution operation is faced with throughput risks associated with declining average use per customer while significant fixed costs are at risk in the usage charge. Unlike many of the proxy companies, Montana-Dakota's Montana natural gas distribution operation does not have the benefit of a decoupling mechanism to ameliorate these risks. Added to these risks is investors' view that the regulatory climate in Montana has been somewhat restrictive, and the rate design risk associated with not having protection against declining sales volume through a revenue decoupling mechanism. These considerations lead me to conclude that investors appraise the overall risks of Montana-Dakota's Montana natural gas distribution operations to be at least as high as the risks of any of the proxy companies. Consequently, Montana-Dakota's Montana natural gas distribution business requires an allowed rate of return that is at the high end of the range for the companies in the proxy group indicated by my DCF analyses.

III. SUMMARY AND CONCLUSIONS

Q39. Please summarize the results of your cost of capital study.

A. I conducted three DCF analyses on a group of natural gas distribution companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota's Montana natural gas distribution operations. These results are summarized as follows:

Table 3: Summary of DCF Results

	Retention Growth DCF Analysis	Basic Analysts DCF	Blended Growth Rate Analysis
High	11.48%	9.62%	10.55%
3rd Quartile	11.18%	9.40%	9.58%
Median	9.16%	8.78%	8.91%
1st Quartile	8.81%	7.53%	8.30%
Low	7.64%	7.39%	8.23%

In addition, I conducted two risk premium analyses to test the reasonableness of my DCF analyses. Those results are summarized as follows:

Table 4: Benchmark Risk Premium Analyses

Corporate Bonds	Return
vs. Large Company Stocks	9.80%
vs. Small Company Stocks	18.60%

In developing my recommendation I have given slightly greater weight to retention growth forecasts because projected retention growth is sustainable indefinitely and it is a good indicator of the minimum growth rate that a company can maintain in the very long run. Moreover, in the current financial climate, which is dominated by short-term Federal Reserve Bank policies designed to artificially manipulate interest rates, the retention growth rates used in my Retention Growth DCF analysis are most consistent with investors' inflation and long-term growth expectations for these gas distribution companies.

My risk premium analyses suggest that the DCF results generally are low relative to historical benchmarks. In particular, the medians of each of the DCF estimation methods are lower than the 9.80 percent risk premium estimate for large companies. Moreover, all of the DCF return estimates are considerably below the 18.60 percent risk-premium return benchmark for companies in the Company's relative size range.

Q40. What rate of return on common equity do you recommend for Montana-Dakota's Montana natural gas distribution operations in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's Montana natural gas distribution operations at this time is 10.50 percent, which is at the top of the range for my Blended Growth Rate analysis. This recommended return also falls between the median and third quartile results for the Retention Growth DCF analysis. This recommended return reflects my assessment that the overall risks of Montana-Dakota's Montana natural gas distribution operations are near the top of the range relative to those of the proxy companies. Although the Company has financial risks that are slightly below average relative to the proxy companies, it has business risks that are above average. In addition to its exceptionally small size relative to the proxy companies, and its exposure to a relatively undiversified local economy, Montana-Dakota's Montana natural gas distribution operations is faced with elevated capital expenditures to replace aging distribution plant even as the Company's average use per customer has declined due to energy efficiency and conservation efforts. This declining usage per customer, combined with significant fixed cost recovery in the usage component of rates, is another distinguishing risk factor. Added to these risks is investors' view that the regulatory climate in Montana has been somewhat restrictive, and the rate design risk associated with not having protection against declining sales volume through a revenue decoupling mechanism. Thus, my recommended return is appropriately positioned to reflect the risks faced by Montana-Dakota's Montana natural gas distribution operations relative to the risks faced by the proxy companies.

Q41. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1974-2011

	[1]	[2]	[3]	[4]	[5]
	Percentage Price Changes				
	Consumer	GDP	Real	Nominal	Nominal
	Price	Implicit Price	GDP	GDP	GDP
Year	Index	Deflator	Growth	($Billions)	Growth
1974	11.0%	9.1%	-0.6%	1,499.5	
1975	9.1%	9.5%	-0.2%	1,637.7	9.2%
1976	5.8%	5.7%	5.4%	1,824.6	11.4%
1977	6.5%	6.4%	4.6%	2,030.1	11.3%
1978	7.6%	7.0%	5.6%	2,293.8	13.0%
1979	11.3%	8.3%	3.1%	2,562.2	11.7%
1980	13.5%	9.1%	-0.3%	2,788.1	8.8%
1981	10.3%	9.4%	2.5%	3,126.8	12.1%
1982	6.2%	6.1%	-1.9%	3,253.2	4.0%
1983	3.2%	4.0%	4.5%	3,534.6	8.6%
1984	4.3%	3.8%	7.2%	3,930.9	11.2%
1985	3.6%	3.0%	4.1%	4,217.5	7.3%
1986	1.9%	2.2%	3.5%	4,460.1	5.8%
1987	3.6%	2.9%	3.2%	4,736.4	6.2%
1988	4.1%	3.4%	4.1%	5,100.4	7.7%
1989	4.8%	3.8%	3.6%	5,482.1	7.5%
1990	5.4%	3.9%	1.9%	5,800.5	5.8%
1991	4.2%	3.5%	-0.2%	5,992.1	3.3%
1992	3.0%	2.4%	3.4%	6,342.3	5.8%
1993	3.0%	2.2%	2.9%	6,667.4	5.1%
1994	2.6%	2.1%	4.1%	7,085.2	6.3%
1995	2.8%	2.1%	2.5%	7,414.7	4.7%
1996	3.0%	1.9%	3.7%	7,838.5	5.7%
1997	2.3%	1.8%	4.5%	8,332.4	6.3%
1998	1.6%	1.1%	4.4%	8,793.5	5.5%
1999	2.2%	1.5%	4.8%	9,353.5	6.4%
2000	3.4%	2.2%	4.1%	9,951.5	6.4%
2001	2.8%	2.3%	1.1%	10,286.2	3.4%
2002	1.6%	1.6%	1.8%	10,642.3	3.5%
2003	2.3%	2.1%	2.5%	11,142.2	4.7%
2004	2.7%	2.8%	3.5%	11,853.3	6.4%
2005	3.4%	3.3%	3.1%	12,623.0	6.5%
2006	3.2%	3.2%	2.7%	13,377.2	6.0%
2007	2.8%	2.9%	1.9%	14,028.7	4.9%
2008	3.8%	2.2%	-0.3%	14,291.5	1.9%
2009	-0.4%	0.9%	-3.1%	13,973.7	-2.2%
2010	1.6%	1.3%	2.4%	14,498.9	3.8%
2011	3.2%	2.1%	1.8%	15,075.7	4.0%
Average Rate of Change [5]:					
1982-2011	3.1%	2.6%	2.7%	5.4%	5.4%
1992-2011	2.5%	2.1%	2.6%	4.7%	4.7%
2002-2011	2.4%	2.3%	1.6%	3.9%	3.9%

Notes:

[1] Department of Labor, Bureau of Labor Statistics, Table Containing History of CPI-U U.S. All Items Indexes and Annual Percent Changes From 1913 to Present, website (http://www.bls.gov/cpi/tables.htm)

[2] Department of Commerce, Bureau of Economic Analysis, Table 1.1.9

[3] Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, GDP-Percent Change from Preceding Period, website(http://bea.gov/national/xls/gdpchg.›

[4] Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, Current-dollar and "real" GDP, website (http://bea.gov/national/xls/gdplev.xls)

[5] Nominal GDP growth rates are based on the geometric average rate of change in nominal

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2007 - June 2012

		[1] 30-Year T-Bonds	[2] Average Corporate	[3] Public Utility Bonds A-Rated	[4] Public Utility Bonds Baa-Rated	[5] Credit Spreads A-Rated	[6] Credit Spreads Baa-Rated
2007	JAN	4.85	5.92	5.96	6.16	1.11	1.31
	FEB	4.82	5.88	5.90	6.10	1.08	1.28
	MAR	4.72	5.84	5.85	6.10	1.13	1.38
	APR	4.86	5.99	5.97	6.24	1.10	1.37
	MAY	4.90	6.00	5.99	6.23	1.08	1.33
	JUN	5.21	6.32	6.30	6.54	1.10	1.34
	JUL	5.10	6.26	6.25	6.49	1.15	1.39
	AUG	4.94	6.26	6.24	6.51	1.30	1.57
	SEP	4.79	6.21	6.18	6.45	1.39	1.66
	OCT	4.78	6.12	6.11	6.36	1.33	1.58
	NOV	4.52	5.97	5.97	6.27	1.45	1.75
	DEC	4.53	6.15	6.16	6.51	1.63	1.98
2008	JAN	4.33	6.02	6.02	6.35	1.68	2.01
	FEB	4.51	6.24	6.21	6.60	1.70	2.08
	MAR	4.38	6.23	6.21	6.68	1.83	2.30
	APR	4.44	6.29	6.29	6.81	1.85	2.37
	MAY	4.60	6.31	6.28	6.79	1.68	2.20
	JUN	4.68	6.43	6.38	6.93	1.70	2.24
	JUL	4.56	6.44	6.40	6.97	1.84	2.41
	AUG	4.50	6.42	6.37	6.98	1.87	2.48
	SEP	4.27	6.50	6.49	7.15	2.22	2.88
	OCT	4.16	7.56	7.56	8.58	3.40	4.42
	NOV	3.98	7.65	7.60	8.98	3.62	5.00
	DEC	2.85	6.71	6.52	8.11	3.68	5.27

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2007 - June 2012

		[1]	[2]	[3]	[4]	[5]	[6]
		30-Year	Average	Public Utility Bonds		Credit Spreads	
		T-Bonds	Corporate	A-Rated	Baa-Rated	A-Rated	Baa-Rated
2009	JAN	3.10	6.59	6.39	7.90	3.29	4.80
	FEB	3.59	6.64	6.30	7.74	2.71	4.15
	MAR	3.64	6.84	6.42	8.00	2.79	4.36
	APR	3.76	6.85	6.48	8.03	2.73	4.27
	MAY	4.24	6.79	6.49	7.76	2.25	3.52
	JUN	4.51	6.52	6.20	7.30	1.69	2.79
	JUL	4.40	6.17	5.97	6.87	1.56	2.47
	AUG	4.37	5.83	5.71	6.36	1.34	1.99
	SEP	4.19	5.61	5.53	6.12	1.34	1.93
	OCT	4.19	5.63	5.55	6.14	1.36	1.95
	NOV	4.31	5.68	5.63	6.17	1.32	1.86
	DEC	4.50	5.78	5.79	6.26	1.29	1.76
2010	JAN	4.60	5.76	5.77	6.16	1.17	1.55
	FEB	4.62	5.86	5.87	6.25	1.25	1.63
	MAR	4.65	5.81	5.84	6.22	1.20	1.58
	APR	4.69	5.80	5.81	6.19	1.12	1.50
	MAY	4.28	5.52	5.50	5.97	1.22	1.69
	JUN	4.12	5.52	5.46	6.18	1.34	2.06
	JUL	3.99	5.32	5.26	5.98	1.27	1.99
	AUG	3.80	5.05	5.01	5.55	1.21	1.75
	SEP	3.77	5.05	5.01	5.53	1.23	1.76
	OCT	3.87	5.15	5.10	5.62	1.24	1.75
	NOV	4.19	5.37	5.37	5.85	1.18	1.66
	DEC	4.42	5.55	5.56	6.04	1.14	1.62

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2007 - June 2012

		[1] 30-Year T-Bonds	[2] Average Corporate	[3] Public Utility Bonds A-Rated	[4] Public Utility Bonds Baa-Rated	[5] Credit Spreads A-Rated	[6] Credit Spreads Baa-Rated
2011	JAN	4.52	5.56	5.57	6.06	1.05	1.54
	FEB	4.65	5.66	5.68	6.10	1.03	1.45
	MAR	4.51	5.55	5.56	5.97	1.05	1.46
	APR	4.50	5.56	5.55	5.98	1.05	1.48
	MAY	4.29	5.33	5.32	5.74	1.03	1.45
	JUN	4.23	5.30	5.26	5.67	1.03	1.44
	JUL	4.28	5.30	5.27	5.70	0.99	1.42
	AUG	3.65	4.79	4.69	5.22	1.04	1.57
	SEP	3.18	4.60	4.48	5.11	1.30	1.93
	OCT	3.12	4.60	4.52	5.24	1.39	2.12
	NOV	3.01	4.39	4.25	4.93	1.24	1.92
	DEC	2.99	4.47	4.33	5.07	1.35	2.08
2012	JAN	3.01	4.45	4.34	5.06	1.32	2.05
	FEB	3.11	4.42	4.36	5.02	1.25	1.91
	MAR	3.28	4.54	4.48	5.13	1.20	1.85
	APR	3.18	4.49	4.40	5.11	1.21	1.93
	MAY	2.92	4.33	4.20	4.97	1.28	2.04
	JUN	2.70	4.22	4.08	4.91	1.39	2.21
2012	AVG	3.03	4.41	4.31	5.03	1.27	2.00

Sources:
[1] Bloomberg Professional, U.S. Government 30-Year Treasury Bond
[2] Bloomberg Professional, Moody's Corporate Average Bond Index
[3] Bloomberg Professional, Moody's A-Rated Utility Bond Index
[4] Bloomberg Professional, Moody's Baa-Rated Utility Bond Index
[5] Equals [3] – [1]
[6] Equals [4] – [1]

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Fiscal Year 2011 Operating Data

		Total Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)	
AGL Resources Inc.	GAS	$13,913.0	$2,338.0	$440.0	1/
Atmos Energy Corp.	ATO	$7,282.9	$4,347.6	$441.9	2/
Laclede Group, Inc.	LG	$1,783.1	$1,603.3	$118.2	2/
New Jersey Resources Corp.	NJR	$2,649.4	$3,009.2	$143.0	2/
Northwest Natural Gas Co.	NWN	$2,746.6	$848.8	$144.8	1/
Piedmont Natural Gas Co., Inc.	PNY	$3,242.5	$1,433.9	$143.0	3/
South Jersey Industries, Inc.	SJI	$2,247.5	$828.6	$121.6	1/
Southwest Gas Corp.	SWX	$4,276.0	$1,887.2	$250.1	1/
High		$13,913	$4,348	$442	
Median		**$2,995**	**$1,745**	**$144**	
Low		$1,783	$829	$118	
Montana-Dakota Utilities Co. - MT Gas Distribution		**$43.2**	**$74.1**	**$4.2**	4/
MDU Resources Group, Inc.		$6,556.1	$4,050.5	$406.4	1/
Montana-Dakota Gas Distribution % of:					
- Proxy Company Median		1.44%	4.25%	2.91%	
- MDU Resources Group, Inc.		0.66%	1.83%	1.03%	

1/ Source: SNL Financial; data as of December 31, 2011
2/ Source: SNL Financial; data as of September 30, 2011
3/ Source: SNL Financial; data as of October 31, 2011
4/ Source: Annual Report of Montana-Dakota Utilities Co. to the Public Service Commission of Montana; data as of December 31, 2011; total assets represented by total rate base

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Bond Ratings

		Standard & Poor's	Moody's
AGL Resources Inc.	GAS	BBB+	Baa1
Atmos Energy Corp.	ATO	BBB+	Baa1
Laclede Group, Inc.	LG	A	Baa2
New Jersey Resources Corp.	NJR	A	Aa3
Northwest Natural Gas Co.	NWN	A+	A3
Piedmont Natural Gas Co., Inc.	PNY	A	A3
South Jersey Industries, Inc.	SJI	BBB+	--
Southwest Gas Corp.	SWX	BBB+	Baa1
Median		**A-**	**Baa1**
MDU Resources Group, Inc.		BBB+	--

Source: Bloomberg Professional and SNL Financial

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Dividend Yields
January 2012 - June 2012

		Stock Price January '12 - June '12				
		High	Low	Average	Dividend	Yield
AGL Resources Inc.	GAS	$40.73	$38.26	$39.50	$1.81	4.59%
Atmos Energy Corp.	ATO	$33.47	$31.41	$32.44	$1.38	4.25%
Laclede Group, Inc.	LG	$41.10	$38.64	$39.87	$1.66	4.16%
New Jersey Resources Corp.	NJR	$46.87	$43.66	$45.26	$1.52	3.36%
Northwest Natural Gas Co.	NWN	$47.69	$45.17	$46.43	$1.78	3.83%
Piedmont Natural Gas Co., Inc.	PNY	$32.82	$30.50	$31.66	$1.19	3.75%
South Jersey Industries, Inc.	SJI	$53.16	$49.49	$51.33	$1.61	3.14%
Southwest Gas Corp.	SWX	$43.57	$40.86	$42.21	$1.10	2.61%
Average						**3.71%**

Source: Bloomberg Professional

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Projected Earnings Retention Growth Rates

		Value Line Forecast 2015-2017				
		EPS	DPS	ROE	Retention Rate	Retention Growth
AGL Resources Inc.	GAS	$4.10	$2.00	12.00%	51.22%	6.15%
Atmos Energy Corp.	ATO	$2.70	$1.48	8.00%	45.19%	3.61%
Laclede Group, Inc.	LG	$3.00	$1.81	11.00%	39.67%	4.36%
New Jersey Resources Corp.	NJR	$3.45	$1.68	14.00%	51.30%	7.18%
Northwest Natural Gas Co.	NWN	$3.40	$1.94	11.50%	42.94%	4.94%
Piedmont Natural Gas Co., Inc.	PNY	$1.85	$1.35	13.00%	27.03%	3.51%
South Jersey Industries, Inc.	SJI	$4.50	$2.25	15.50%	50.00%	7.75%
Southwest Gas Corp.	SWX	$3.75	$1.60	10.50%	57.33%	6.02%
Average						**5.44%**

Source: Value Line, June 8, 2012.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Blended Growth Rate Estimates

		1/2 Zacks 5-Yr Earnings Growth Est.	1/2 Retention Growth	Weighted Average
AGL Resources Inc.	GAS	4.28%	6.15%	5.21%
Atmos Energy Corp.	ATO	4.78%	3.61%	4.20%
Laclede Group, Inc.	LG	3.00%	4.36%	3.68%
New Jersey Resources Corp.	NJR	3.80%	7.18%	5.49%
Northwest Natural Gas Co.	NWN	4.30%	4.94%	4.62%
Piedmont Natural Gas Co., Inc.	PNY	4.78%	3.51%	4.15%
South Jersey Industries, Inc.	SJI	6.00%	7.75%	6.88%
Southwest Gas Corp.	SWX	4.43%	6.02%	5.23%
Average		**4.42%**	**5.44%**	**4.93%**
Median		**4.37%**	**5.48%**	**4.92%**

Source: Zacks.com and page 4.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Retention Growth DCF Calculation

		Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
AGL Resources Inc.	GAS	4.59%	4.77%	6.15%	10.91%	1.0400	11.35%
Atmos Energy Corp.	ATO	4.25%	4.35%	3.61%	7.97%	1.0400	8.28%
Laclede Group, Inc.	LG	4.16%	4.28%	4.36%	8.64%	1.0400	8.99%
New Jersey Resources Corp.	NJR	3.36%	3.51%	7.18%	10.69%	1.0400	11.12%
Northwest Natural Gas Co.	NWN	3.83%	3.95%	4.94%	8.89%	1.0400	9.25%
Piedmont Natural Gas Co., Inc.	PNY	3.75%	3.83%	3.51%	7.34%	1.0400	7.64%
South Jersey Industries, Inc.	SJI	3.14%	3.29%	7.75%	11.04%	1.0400	11.48%
Southwest Gas Corp.	SWX	2.61%	2.70%	6.02%	8.72%	1.0400	9.07%
High					11.04%		11.48%
3rd Quartile					10.75%		11.18%
2nd Quartile (Median)					**8.81%**		**9.16%**
1st Quartile					8.47%		8.81%
Low					7.34%		7.64%

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Basic DCF Calculation

		Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
AGL Resources Inc.	GAS	4.59%	4.71%	4.28%	8.99%	1.0400	9.35%
Atmos Energy Corp.	ATO	4.25%	4.38%	4.78%	9.16%	1.0400	9.53%
Laclede Group, Inc.	LG	4.16%	4.24%	3.00%	7.24%	1.0400	7.53%
New Jersey Resources Corp.	NJR	3.36%	3.44%	3.80%	7.24%	1.0400	7.53%
Northwest Natural Gas Co.	NWN	3.83%	3.94%	4.30%	8.24%	1.0400	8.57%
Piedmont Natural Gas Co., Inc.	PNY	3.75%	3.86%	4.78%	8.64%	1.0400	8.99%
South Jersey Industries, Inc.	SJI	3.14%	3.25%	6.00%	9.25%	1.0400	9.62%
Southwest Gas Corp.	SWX	2.61%	2.68%	4.43%	7.11%	1.0400	7.39%
High					9.25%		9.62%
3rd Quartile					9.04%		9.40%
2nd Quartile (Median)					**8.44%**		**8.78%**
1st Quartile					7.24%		7.53%
Low					7.11%		7.39%

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Blended Growth Rate DCF Calculation

		Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
AGL Resources Inc.	GAS	4.59%	4.74%	5.21%	9.95%	1.0400	10.35%
Atmos Energy Corp.	ATO	4.25%	4.37%	4.20%	8.56%	1.0400	8.91%
Laclede Group, Inc.	LG	4.16%	4.26%	3.68%	7.94%	1.0400	8.26%
New Jersey Resources Corp.	NJR	3.36%	3.47%	5.49%	8.96%	1.0400	9.32%
Northwest Natural Gas Co.	NWN	3.83%	3.94%	4.62%	8.56%	1.0400	8.91%
Piedmont Natural Gas Co., Inc.	PNY	3.75%	3.85%	4.15%	7.99%	1.0400	8.31%
South Jersey Industries, Inc.	SJI	3.14%	3.27%	6.88%	10.15%	1.0400	10.55%
Southwest Gas Corp.	SWX	2.61%	2.69%	5.23%	7.92%	1.0400	8.23%
High					10.15%		10.55%
3rd Quartile					9.21%		9.58%
2nd Quartile (Median)					**8.56%**		**8.91%**
1st Quartile					7.98%		8.30%
Low					7.92%		8.23%

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Capital Structures as of March 31, 2012

in millions

		Short-Term Debt	%	Long-Term Debt	%	Preferred Stock	%	Common Equity	%	Total Capital	
AGL Resources Inc.	GAS	$730.0	9.44%	$3,575.0	46.24%	$0.0	0.00%	$3,426.0	44.32%	$7,731.0	1/
Atmos Energy Corp.	ATO	$174.0	3.67%	$2,206.3	46.54%	$0.0	0.00%	$2,360.7	49.79%	$4,741.1	1/
Laclede Group, Inc.	LG	$0.0	0.00%	$364.7	37.22%	$0.0	0.00%	$615.2	62.78%	$979.9	1/
New Jersey Resources Corp.	NJR	$191.3	12.83%	$437.6	29.35%	$0.0	0.00%	$862.2	57.83%	$1,491.1	1/
Northwest Natural Gas Co.	NWN	$113.7	7.57%	$641.7	42.74%	$0.0	0.00%	$746.0	49.69%	$1,501.4	1/
Piedmont Natural Gas Co., Inc.	PNY	$80.0	3.77%	$975.0	45.99%	$0.0	0.00%	$1,064.8	50.23%	$2,119.8	2/
South Jersey Industries, Inc.	SJI	$344.7	23.96%	$426.4	29.63%	$0.0	0.00%	$667.8	46.41%	$1,438.9	1/
Southwest Gas Corp.	SWX	$0.0	0.00%	$1,393.1	51.83%	$0.0	0.00%	$1,294.6	48.17%	$2,687.7	1/
Median			**5.67%**		**44.37%**		**0.00%**		**49.74%**		

1/ Source: SNL Financial; data as of March 31, 2012
2/ Source: SNL Financial; data as of April 30, 2012

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of
Natural Gas Distribution Companies
2000-2012

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
SEMCO Energy, Inc.	6/12/2000	9,000,000	$10.000	$9.600	4.17%
NiSource Inc.	11/30/2000	10,000,000	$25.250	$24.430	3.36%
Atmos Energy Corporation	12/14/2000	6,000,000	$22.250	$21.140	5.25%
Vectren Corporation	2/8/2001	5,500,000	$21.270	$20.530	3.60%
UtiliCorp United, Inc.	3/5/2001	10,000,000	$29.760	$28.940	2.83%
WGL Holdings, Inc.	6/20/2001	1,790,000	$26.730	$25.835	3.46%
UtiliCorp United, Inc.	1/25/2002	11,000,000	$23.000	$22.253	3.36%
NUI Corporation	3/14/2002	1,500,000	$22.500	$21.430	4.99%
Aquila, Inc.	6/27/2002	37,500,000	$7.500	$7.256	3.36%
NiSource Inc.	11/6/2002	36,000,000	$18.300	$17.751	3.09%
MDU Resources Group, Inc.	11/19/2002	2,100,000	$24.000	$23.280	3.09%
KeySpan Corporation	1/13/2003	13,900,000	$34.500	$34.070	1.26%
Cinergy Corporation	1/31/2003	5,700,000	$31.100	$30.850	0.81%
AGL Resources Inc.	2/11/2003	5,600,000	$22.000	$21.230	3.63%
Delta Natural Gas Company, Inc.	4/29/2003	525,000	$21.600	$20.650	4.60%
Southern Union Company	6/5/2003	9,500,000	$16.000	$15.440	3.63%
Atmos Energy Corporation	6/17/2003	4,000,000	$25.310	$24.298	4.17%
Vectren Corporation	8/7/2003	6,500,000	$22.810	$22.012	3.63%
Sempra Energy	10/8/2003	15,000,000	$28.000	$27.160	3.09%
Unitil Corporation	10/23/2003	624,000	$25.400	$24.130	5.26%
Piedmont Natural Gas Company, Inc	1/20/2004	4,250,000	$42.500	$41.010	3.63%
MDU Resources Group, Inc.	2/4/2004	2,000,000	$23.320	$22.527	3.52%
UGI Corporation	3/18/2004	7,500,000	$32.100	$30.696	4.58%
Northwest Natural Gas Company	3/30/2004	1,200,000	$31.000	$29.990	3.37%
The Laclede Group, Inc.	5/25/2004	1,500,000	$26.800	$25.929	3.36%
Atmos Energy Corporation	7/13/2004	8,650,000	$24.750	$23.760	4.17%
Southern Union Company	7/26/2004	11,000,000	$18.750	$18.094	3.63%
Aquila, Inc.	8/18/2004	40,000,000	$2.550	$2.451	4.04%
Atmos Energy Corporation	10/21/2004	14,000,000	$24.750	$23.760	4.17%
AGL Resources Inc.	11/19/2004	9,600,000	$31.010	$30.080	3.09%
Cinergy Corporation	12/9/2004	6,100,000	$41.000	$40.510	1.21%
Southern Union Company	2/7/2005	14,910,000	$23.000	$22.300	3.14%
SEMCO Energy, Inc.	8/10/2005	4,300,000	$6.320	$6.067	4.17%
Chesapeake Utilities Corporation	11/16/2006	600,300	$30.100	$28.975	3.88%
Atmos Energy Corporation	12/7/2006	5,500,000	$31.500	$30.398	3.63%
Vectren Corporation	2/22/2007	4,600,000	$28.330	$27.338	3.63%
Unitil Corporation	12/10/2008	2,000,000	$20.000	$18.950	5.54%
Unitil Corporation	5/20/2009	2,400,000	$20.000	$18.950	5.54%
CenterPoint Energy, Inc.	9/10/2009	21,000,000	$12.000	$11.580	3.63%
CenterPoint Energy, Inc.	6/9/2010	22,000,000	$12.900	$12.449	3.63%
NiSource Inc.	9/8/2010	21,100,000	$16.500	$15.964	3.36%
Gas Natural Inc.	11/10/2010	2,100,000	$10.000	$9.400	6.38%
Unitil Corporation	5/10/2012	2,400,000	$25.250	$23.988	5.26%
Gas Natural Inc.	6/27/2012	700,000	$10.100	$9.494	6.38%
		Average 2000-2012:			3.81%
		Selected Flotation Costs for Cost of Equity:			4.00%

Sources: EBASCO, *Analysis of Public Utility Financing* and *Public Utility Financing Tracker;* Bloomberg

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Decoupling Mechanisms

Proxy Group Company		Utility	State	Decoupling	# of Customers	% of Total Customers
AGL Resources Inc.	GAS	Atlanta Gas Light Company	GA	Y	1,541,000	12%
AGL Resources Inc.	GAS	Northern Illinois Gas Company	IL	N	2,188,000	17%
AGL Resources Inc.	GAS	Elizabethtown Gas	NJ	N	276,000	2%
AGL Resources Inc.	GAS	Florida City Gas	FL	N	103,000	1%
AGL Resources Inc.	GAS	Elkton Gas	MD	Y	6,000	0%
AGL Resources Inc.	GAS	Chattanooga Gas Company	TN	Y	62,000	0%
AGL Resources Inc.	GAS	Virginia Natural Gas, Inc.	VA	N	278,000	2%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	CO	N	110,900	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	GA	Y	59,982	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	IL	N	22,537	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	IA	N	4,281	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	KS	N	128,207	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	KY	N	176,246	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	LA	Y	343,598	3%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	MS	Y	258,913	2%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	MO	N	55,890	0%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	TN	N	130,395	1%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	TX	Y	1,873,236	15%
Atmos Energy Corp.	ATO	Atmos Energy Corp.	VA	N	22,373	0%
Laclede Group, Inc.	LG	Laclede Gas Company	MO	N	639,895	5%
New Jersey Resources Corp.	NJR	New Jersey Natural Gas Company	NJ	Y	495,383	4%
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	OR	Y	606,988	5%
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	WA	N	72,555	1%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	NC	Y	671,434	5%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	SC	Y	132,169	1%
Piedmont Natural Gas Company, Inc.	PNY	Piedmont Natural Gas Company, Inc.	TN	N	166,216	1%
South Jersey Industries, Inc.	SJI	South Jersey Gas Company	NJ	Y	348,868	3%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	AZ	Y	1,001,476	8%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	CA	Y	181,644	1%
Southwest Gas Corp.	SWX	Southwest Gas Corp.	NV	Y	662,249	5%
Total Number of Customers					12,619,435	
Percent with Decoupling					65.34%	

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2012.9.__

Direct Testimony
of
Rita A. Mulkern

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

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

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

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

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

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Would you please describe your education and professional background?

A. I graduated from North Dakota State University with a Bachelor of Arts degree with majors in Economics and Business Administration and a minor in Statistics. I joined Montana-Dakota in July 1981 as a Regulatory

Statistician, became Cost of Service Supervisor in 1986, Regulatory Analysis Manager in 1999, Regulatory Affairs Manager in 2010 and my current position in 2012.

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

A. Yes, I have presented testimony before the Public Service Commissions of Montana, North Dakota, and Wyoming and the Minnesota and South Dakota Public Utilities Commissions.

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

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

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

A. The purpose of my testimony is to present the per books cost of service for the twelve months ended December 31, 2011, the pro forma cost of service reflecting known and measurable adjustments that will occur by December 2012, the pro forma cost of service supporting the request for interim rate relief and the calculation of the interim and final revenue deficiencies. I will also address the recovery of amounts deferred related to the Montana Public Service Commission Tax and Montana Consumer Counsel Tax pursuant to the Commission's Order in Docket No. N2010.10.105.

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

A. I am sponsoring Statements C through E, Statement G, Statement H, pages 1-6, Statements I through K, Statements N and O, Part A, the Interim Statements C through E, Statement H, pages 1-6 and Statements I through K, Statement O and Exhibit No.___(RAM-1) through Exhibit No. ___(RAM-3).

Pro forma revenue requirement

Q. What were the results of Montana gas operations for the twelve months ended December 31, 2011?

A. Rule 38.5.175, pages 1 and 2 show the per books income statement and rate base for total Company and Montana. As shown on page 1, Montana gas operations had a return on rate base of 8.390 percent for the twelve months ended December 31, 2011. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement or rule listed. Pages 3 and 4 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a Montana specific basis or on a total Company basis and allocated to Montana, as indicated on the statement or schedule detailing each adjustment.

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

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

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

A. The pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2012, conform to past Commission practices and are listed on pages 3 and 4 of Rule 38.5.175. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

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

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

<u>Pro Forma Income Statement</u>

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 38.5.164, Statement H. Adjustment No. 1 restates the per books consumption at current rates, adjusted to reflect an annual gas cost for 2012, exclusive of the unreflected gas cost adjustment, and eliminates the unbilled revenue, decreasing revenue by $13,609,329.

Adjustment No. 2 decreases revenues by $1,467,031 to reflect the effect of normal weather on sales and transportation volumes, as weather was 5.6 percent colder than normal in 2011.

Adjustment No. 3 is an increase to revenues of $257,226 to reflect the annualization of firm customers to the December 2011 level.

Adjustment No. 4 includes the adjustments to other operating revenues. The pro forma adjustment consists of the inclusion of late payment revenue, a three year average of penalty revenue and the five year amortization of the net gains and losses on the sale of land and office buildings in Montana that were no longer needed. The net gains and losses occurred during the period 2007-2011.

Q. **What adjustments were made to O&M expenses?**

A. The adjustments to operation and maintenance expenses are contained in Rule 38.5.157, Statement G, and are summarized in Rule 38.5.156.

The adjustment to the cost of gas (Adjustment No. 5) is shown on Rule 38.5.157, page 3, and adjusts the cost of gas to reflect the pro forma dk sales and an annual 2012 gas cost level. The pro forma cost of gas per dk was derived by calculating annual demand charges and commodity cost of gas and applying those costs to the August 2012 gas cost tracking adjustment billing determinants. The distribution loss factor of 0.72 percent represents the current loss factor.

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

A. The adjustment to labor is Adjustment No. 6. The pro forma labor was developed by applying the percentage increase in total Company labor costs to the actual 2011 Montana labor expense. The labor expense for 2012 was developed by applying the projected percentage increase in total Company labor costs to the 2011 per books Montana labor expense. Projected total Company labor costs were based on the application of an overall increase of 3.0 percent for union employees and 2.5 percent for nonunion employees effective in 2012 with incentive compensation adjusted to reflect a three year average and severance amounts paid in 2009 amortized over three years. This results in a 4.74 percent increase for 2012.

Benefits are shown on page 5. Adjustment No. 7 is an overall decrease of $75,501 in benefits. Benefits expense consists of medical/dental insurance, pension expense, post-retirement, 401K, workers compensation, other benefits and supplemental insurance. Each of these items, excluding other benefits and supplemental insurance, was adjusted individually using current information and applying the percentage increase to each type of benefit.

Medical and dental expense is increasing slightly by 0.89 percent. Pension expense is decreasing 141.48 percent due to a change in the union benefit plan as discussed by Ms. Jones. Post-retirement expense is increasing significantly by 151.94 percent over 2011 levels due to a true-up related to the prior years' amortization, a reduction in the expected return on plan investments and a reduction in the discount rate used in the actuarial study. The 401K expense will increase 14.0 percent resulting from the change in the pension plan for union employees. Workers compensation is based on the 2011 per books ratio of workers compensation to per books labor expense and applied to pro forma labor expense. The Supplemental Income Security Plan (SISP) was eliminated in accordance with past Commission decisions.

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

A. Yes. Vehicles and work equipment (Adjustment No. 8) reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, including the costs of fuel, insurance, maintenance and depreciation expense. Adjustment No. 8 reflects a decrease in this account due to the change in the depreciation component of the expense. It is calculated based on the pro forma plant and the depreciation rates in Statement I. The depreciation expense on these items is not charged to depreciation expense but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used.

Company consumption (Adjustment No. 9) is the expense for electric and natural gas consumption in Company buildings. The electric component is projected to remain flat. The natural gas component is expected to decrease $8,120 based on the decrease in normalized sales revenues.

Uncollectible accounts (Adjustment No. 10) is a decrease based on the five year average of net write-offs to pro forma sales and transportation revenues, which results in a decrease in uncollectible accounts of $14,963. The decrease is the result of the lower gas costs that customers have been experiencing, while the percent of write-offs has remained fairly stable.

Advertising expense (Adjustment No. 11) is shown on page 9. Pursuant to past Commission policy, general promotional and institutional advertising expense has been eliminated. Informational advertising is adjusted to exclude advertising that was recorded in the incorrect account.

Insurance expense (Adjustment No. 12) reflects the expense at current levels for 2012 and is an increase of $13,839.

Industry dues (Adjustment No. 13) reflects the pro forma level of industry dues and is a decrease of $7,138. Rule 38.5.157, Statement G, page 11 shows those dues that are directly assigned or allocated to Montana.

Regulatory Commission Expense (Adjustment No. 14) reflects the expenses to be incurred in this filing, amortized over a three-year period and a three year average of ongoing regulatory commission expenses. The adjustment is an increase of $108,300.

The items adjusted individually above represent approximately 80 percent of total Montana gas O&M, as shown on page 13. The remaining items, which make up approximately 20 percent of other O&M, are assumed to remain flat.

Q. What adjustments were made to depreciation expense?

A. The adjustment to depreciation expense is contained in Rule 38.5.165, Statement I. Adjustment No. 15 restates annual depreciation expense to the average pro forma level of plant in service, with the proposed depreciation rates from a 2008 study prepared by AUS Consultants. The depreciation rates are shown on Statement I, pages 5 through 8. Mr. Earl Robinson's testimony supports the proposed depreciation rates.

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

A. The adjustments to taxes other than income are contained in Rule 38.5.174, Statement K. Adjustment No. 16 restates ad valorem taxes to the pro forma level of plant in service based on the 2011 ratio of ad valorem taxes to plant and is an increase of $114,387.

The adjustment to payroll taxes (Adjustment No. 17) is an increase of $20,322 based on the ratio of payroll taxes to labor expense for 2011 applied to pro forma labor expense.

The Montana Consumer Counsel Tax and Public Service Commission taxes are restated in Adjustment No. 18 to the pro forma level of revenue and the rate effective October 1, 2011 and results in a decrease of $167,229.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are contained in Rule 38.5.169, Statement J. The adjustment to interest expense (Adjustment No. 19) is shown on page 8. Interest is deductible for tax purposes and interest expense is calculated on the pro forma rate base using the weighted cost of debt and debt ratio from Statement F. The resulting interest expense is a decrease of $51,878 from the per books level.

The adjustments for tax depreciation and deferred taxes on the pro forma plant additions (Adjustment No. 20) are shown on page 9. The calculation of tax depreciation on the plant additions on page 18 reflects the bonus tax depreciation rate of 50 percent for 2012 .

Other tax deductions for SISP and 401K were eliminated in Adjustment No. 21 on page 10. The SISP tax deductions are eliminated to match the elimination of the SISP expense from benefits and the 401K deduction relates to an election by MDU Resources and thus not attributable to customers. There is a corresponding adjustment to deferred taxes for the SISP adjustment.

The current income tax expense on all of the pro forma adjustments to operating revenues and expenses are calculated on page 11 in Adjustment No. 22.

The closing/filing and prior period adjustments in the current income tax accrual and in the deferred taxes are eliminated in Adjustment No. 23. This adjustment adjusts current and deferred income taxes to the calculated amount for Montana and conforms to past Commission practices.

Rate Base

Q. How was the rate base developed?

A. The pro forma rate base is based on the average 2011 rate base and reflects known and measurable adjustments that will occur twelve months beyond December 31, 2011. The resulting rate base is stated on an average basis. The pro forma adjustments to rate base are summarized on Rule 38.5.175, page 5. Adjustment A is the known and measurable plant additions that will be in service by December 31, 2012. The additions of $6,357,622 include additions to production, distribution, general and common plant and are shown on Rule 38.5.124, Statement C, pages 6 and 7. Several significant projects since the last general rate case that are reflected in plant in service or are proposed plant additions include the Billings Landfill production facility, discussed by Mr. Morman, the new customer information system discussed by Mr. Gardner and the distribution plant projects and Rocky Mountain Region office building discussed by Mr. Skabo.

Adjustment B, shown in Rule 38.5.133, Statement D, increases the average reserve for depreciation on the per books plant by $3,202,646 to restate the reserve to the average pro forma level in order to match the average pro forma plant levels.

The working capital adjustments are included in Rule 38.5.141, Statement E. Materials and supplies are restated to a thirteen-month average balance in Adjustment C, for an increase of $99,695.

The gas in underground storage (Adjustment D) restates the gas in underground storage balance to a thirteen month balance for 2012 and is a decrease of $855,502. The pro forma storage reflects actual balances through June 30, 2012 with the remaining months of 2012 based on the pro forma cost of gas and projected injections to and withdrawals of gas from storage.

Insurance expense is restated to a thirteen month average balance in Adjustment E with actual balances through June 30, 2012 and balances for July through December 2012 based on the pro forma insurance expense and is an increase of $93,808.

Prepaid demand and commodity balances reflect actual balances through June 30, 2012 and projected balances for July through December 2012 and are also restated to a thirteen month average balance in Adjustment F, for a decrease of $642,915.

The average net unamortized gain(loss) on reacquired debt balances as of December 31, 2012 is included as Adjustment G.

The average net Provision for Pensions and Benefits as of December 31, 2011 and the associated deferred income taxes is included as Adjustment H in conformance with Order 5856b in Docket No. D95.7.90.

The average Provision for Injuries and Damages as of December 31, 2011 is included as Adjustment I in conformance with Order 5856b in Docket No. D95.7.90.

Deferred FAS 106 costs and the associated deferred income taxes are included as Adjustment J. The balance reflects the average balance over the twenty year period pursuant to the Commission's Order 5856g in Docket No. D95.7.90.

The adjustments to accumulated deferred income taxes are summarized on Rule 38.5.169, Statement J, page 17. Adjustment K is the increase to deferred taxes to extend the average accumulated deferred tax balance to match the pro forma plant and accumulated reserve along with prepaid demand charges and customer advances.

Adjustment L is the decrease to deferred taxes to reflect the amortization of the full normalization for 2012.

The deferred taxes associated with the unamortized loss on debt (Adjustment G), provision for pensions and benefits (Adjustment H), provision for injuries and damages (Adjustment I) and deferred FAS 106 costs (Adjustment J) are also included on page17.

Accumulated investment tax credits (ITCs) are restated to extend the average ITC balances to match the pro forma plant and accumulated reserve in Adjustment M, reflecting a decrease of $3,488.

Customer advances for construction are restated to a thirteen-month average balance, with actual balances through June 30, 2012 and is a decrease of $20,926 as shown on Rule 38.5.143, page 9.

These are all of the pro forma adjustments to revenue, expense and rate base.

Q. What does Rule 38.5.190, Statement O show?

A. The charts and graphs contained in Rule 38.5.190, Statement O, Part A are the pictorial exhibits required by Commission rules.

Q. What is the additional revenue requirement calculated on Exhibit No.____(RAM-1)?

A. Exhibit No.____(RAM-1), which is identical to Rule 38.5.175, page 8, shows the calculation of the revenue deficiency of $3,455,478 based on the pro forma operating income and rate base and using the overall rate of return of 8.489 percent from Rule 38.5.146, Statement F, page 1.

<u>Proposed recovery of deferred MCC and PSC taxes</u>

Q. Montana-Dakota was authorized, in Docket Nos. N2010.11.105 and N2011.10.90, to defer the revenues associated with the change in the Public Commission Service (PSC) Tax rate and the Consumer Counsel Tax (MCC) rate, both over and under recoveries. Is Montana-Dakota proposing to recover (return) this deferred balance?

A. Yes, Montana-Dakota is proposing to recover the under recovered amounts of PSC and MCC tax for the period October 1, 2010 through

June 30, 2012 and utilize the gas cost tracking adjustment mechanism (gas tracker) as the vehicle to recover the deferred amounts.

In Docket Nos. N2010.11.105 and N2011.10.90, Montana-Dakota requested authority to defer the difference between the PSC and MCC taxes recovered and the actual taxes incurred. Effective November 1, 2009, Montana-Dakota's rates included PSC and MCC tax rates of 0.21 percent and 0.03 percent respectively. In October 2010, the PSC and MCC tax rates changed to 0.37 percent and 0.03 percent respectively, and effective in October 2011 the PSC and MCC tax rates changed to 0.42 percent and 0.11 percent respectively. Overall the tax rates were higher than the level embedded in rates and Montana-Dakota under recovered its tax costs. Exhibit No. ___(RAM-2) shows that Montana-Dakota under recovered the taxes by $199,908 for the period October 2010 through June 2012 for the residential and firm general service customers. Montana-Dakota did not defer the differences for interruptible customers as such amounts are small and most large interruptible customers take service on a flexible rate.

Montana-Dakota is proposing to recover these deferred costs as they were prudently incurred costs. The Company also proposes to recover the deferred amount from firm customers over a one year period on a per dk basis based on projected residential and firm sales and to utilize the gas cost tracking adjustment as the most efficient mechanism to recover the cost. The adjustment will not be included in the cost of gas, but will simply use the mechanism as the means of recovering the taxes. Since the gas tracker changes monthly, the deferred tax recovery can begin upon Commission approval and cease when it is fully recovered. The estimated recovery per dk over the annual period would be approximately 2 cents per dk.

<u>Interim revenue requirement</u>

Q. Would you please describe the derivation of the interim increase?

A. Yes. The interim increase has been developed in a separate set of Interim Statements pursuant to the Commission's rules regarding interim rate increase requests in general rate proceedings (Administrative Rules of Montana 38.5.505 and 38.5.506).

The derivation of the interim request follows Commission approved methodology and consists of adjustments to revenue, expense and rate base. The interim request is based on the capital structure and debt costs proposed by the Company, including a return on equity of 10.50 percent. While in previous cases the Company has used the authorized capital structure and costs, in this case the pro forma capital structure was used as the overall return last authorized by the Commission in Docket No. D95.7.90 was 10.913 percent and the Company's proposed overall rate of return in this case is 8.489 percent, which is lower than the currently authorized return. The pro forma adjustments to revenue and expense are listed on Rule 38.5.175, page 2.

Q. Would you describe the interim adjustments to operating revenues?

A. The interim adjustments to operating revenues are contained in Rule 38.5.164, Statement H. Adjustment No. 1 restates the per books consumption at current rates, adjusted to reflect an annual gas cost for 2012, exclusive of the unreflected gas cost adjustment, and eliminates the unbilled revenue, decreasing revenue by $13,609,329.

Adjustment No. 2 decreases revenues by $1,467,031 to reflect the effect of normal weather on sales and transportation volumes, as weather was 5.6 percent colder than normal in 2011.

Adjustment No. 3 is an increase to revenues of $257,226 to reflect the annualization of firm customers to the December 2011 level.

Adjustment No. 4 includes the adjustments to other operating revenues. The pro forma adjustment consists of the inclusion of late payment revenue, a three year average of penalty revenue and the five year amortization of the net gains and losses on the sale of land and office buildings in Montana that were no longer needed. The net gains and losses occurred during the period 2007-2011.

Q. What interim adjustments were made to operation and maintenance expenses?

A. The interim adjustments to operation and maintenance expenses are contained in Rule 38.5.157, Statement G, and are summarized in Rule 38.5.156.

The cost of gas is adjusted (Adjustment No. 5) to reflect the normalized and annualized dk sales and an annual 2012 gas cost level.

The pro forma cost of gas per dk was derived by calculating annual demand charges and commodity cost of gas and applying those costs to the August 2012 gas cost tracking adjustment billing determinants. The distribution loss factor of .72 percent represents the current loss factor.

The adjustment to labor is Adjustment No. 6. The adjustment to labor was developed by applying the percentage increase in total Company labor costs to the actual 2011 Montana labor expense. The labor expense for 2012 was developed by applying the projected percentage increase in total Company labor costs to the 2011 per books Montana labor expense. Projected total Company labor costs were based on the application of an overall increase of 3.0 percent for union employees and 2.5 percent for nonunion employees effective in 2012 with incentive compensation adjusted to reflect a three year average and severance amounts paid in 2009 amortized over three years. This results in a 4.74 percent increase for 2012.

Adjustment No. 7 to benefits is an overall decrease of $75,501 in benefits. Benefits expense consists of medical/dental insurance, pension expense, post-retirement, 401K, workers compensation, other benefits and supplemental insurance. Each of these items, excluding other benefits and supplemental insurance, was adjusted individually using current information and applying the percentage increase to each type of benefit.

Medical and dental expense is increasing slightly by 0.89 percent. Pension expense is decreasing 141.48 percent due to a change in the union benefit plan. Post-retirement expense is increasing significantly by 151.94 percent over 2011 levels due to the a reduction in the expected return and in the discount rate used in the actuarial study while 401K expense will increase 14.0 percent and workers compensation is based on the 2011 per books workers compensation to pro forma labor expense. The Supplemental Income Security Plan (SISP) was eliminated in accordance with past Commission decisions.

Vehicles and work equipment (Adjustment No. 8) reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, including the costs of fuel, insurance, maintenance and depreciation expense. Adjustment No. 8 reflects a decrease in this account due to the change in the depreciation component of the expense. It is calculated based on the pro forma plant and the depreciation rates in Statement I. The depreciation expense on these items is not charged to depreciation expense but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used.

Company consumption (Adjustment No. 9) is the expense for electric and natural gas consumption in Company buildings. The electric component is projected to remain flat. The natural gas component is expected to decrease $8,120 based on the decrease in normalized sales revenues.

Uncollectible accounts (Adjustment No. 10) is a decrease based on the five year average of net write-offs to pro forma sales and transportation revenues, which results in a decrease in uncollectible accounts of $14,963. The decrease is the result of the lower gas costs that customers have been experiencing, while the percent of write-offs has remained fairly stable.

Advertising expense (Adjustment No. 11) is shown on page 9. Pursuant to past Commission policy, general promotional and institutional advertising expense has been eliminated. Informational advertising is adjusted to exclude advertising that was recorded in the incorrect account.

Insurance expense (Adjustment No. 12) reflects the expense at current levels for 2012 and is an increase of $13,839.

Industry dues (Adjustment No. 13) reflects the pro forma level of industry dues and is a decrease of $7,138. Rule 38.5.157, Statement G, page 11 shows those dues that are directly assigned or allocated to Montana.

Q. What interim adjustments were made to depreciation expense?

A. The interim adjustment to depreciation expense is contained in Rule 38.5.165, Statement I. Adjustment No. 14 restates annual depreciation expense to the average plant in service level. The depreciation rates reflect the proposed rates from the 2008 gas and common studies supported by Mr. Robinson, with the exception of distribution rates. For interim purposes, the distribution depreciation rates reflect the currently effective rates. As noted by Mr. Senger, the depreciation rates from the gas and common 2008 depreciation studies, with the exclusion of the proposed cost of removal rates, were lower than the prior rates based on a December 31, 2001 study and therefore the 2008 study rates, adjusted to include the existing cost of removal rates for distribution plant, were implemented in 2010. Montana-Dakota is using the currently effective rates as shown in Statement I, pages 6 and 7 to determine the interim depreciation expense level.

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

A. The interim adjustments to taxes other than income are contained in Rule 38.5.173, Statement K. Ad valorem taxes are restated in Adjustment No. 15 to the pro forma interim level of plant in service, based on the 2011 ratio of ad valorem taxes to plant and is an increase of $13,556.

The adjustment to payroll taxes (Adjustment No. 16) is an increase of $20,322 based on the ratio of payroll taxes to labor expense for 2011 applied to pro forma labor expense.

The MCC and PSC taxes are restated in Adjustment No. 17 to the pro forma interim level of revenue and the rate effective October 1, 2011 and are a decrease of $167,229.

Q. What adjustments were made to income taxes?

A. The interim adjustments to income taxes are contained in Rule 38.5.169, Statement J. The adjustment to interest expense (Adjustment No. 18) is shown on page 2. Interest is deductible for tax purposes and interest expense is calculated on the pro forma interim rate base using the weighted cost of debt and debt ratio from Statement F. The resulting interest expense is a decrease of $85,734 from the per books level.

Other tax deductions for SISP and 401K were eliminated in Adjustment No. 19 on page 3. The SISP tax deductions are eliminated to match the elimination of the SISP expense from benefits and the 401K deduction relates to an election by MDU Resources and thus not attributable to customers. There is a corresponding adjustment to deferred taxes for the SISP adjustment.

The current income tax expense on all of the interim pro forma adjustments to operating revenues and expenses are calculated on page 4 in Adjustment No. 20.

The closing/filing and prior period adjustments in the current income tax accrual and in the deferred taxes are eliminated in Adjustment No. 21. This adjustment adjusts current and deferred income taxes to the calculated amount for Montana and conforms to past Commission practices.

Q. What interim adjustments were made to rate base?

A. The pro forma interim adjustments to rate base are listed on Rule 38.5.175, page 4.

Materials and supplies are restated to a thirteen-month average balance in Adjustment A, for an increase of $99,695.

The gas in underground storage (Adjustment B) restates the gas in underground storage balance to a thirteen month balance for 2012 and is a decrease of $855,502. The pro forma storage reflects actual balances through June 30, 2012 with the remaining months of 2012 based on the pro forma cost of gas.

Insurance expense is restated to a thirteen month average balance in Adjustment C based on the pro forma insurance expense and is an increase of $93,808.

Prepaid demand and commodity balances reflect actual balances through June 30, 2012 and are also restated to a thirteen month average balance in Adjustment D, a decrease of $642,915.

The average net Provision for Pensions and Benefits as of December 31, 2011 and the associated deferred income taxes is included as Adjustment E in conformance with Order 5856b in Docket No. D95.7.90.

The average Provision for Injuries and Damages as of December 31, 2011 is included as Adjustment F in conformance with the Order 5856b in Docket No. D95.7.90.

Deferred FAS 106 costs and the associated deferred income taxes are included as Adjustment G. The balance reflects the average balance over the twenty year period pursuant to Order 5856g in Docket No. D95.7.90.

Adjustment J, shown on Rule 38.5.169, page 8, is the decrease to deferred taxes to reflect the amortization of the full normalization for 2011.

Customer advances for construction are restated to a thirteen-month average balance, with actual balances through June 30, 2012 and is a decrease of $20,926 in Adjustment H.

These are all of the pro forma adjustments to revenue, expense and rate base related to the interim request.

Q. What does Exhibit No.____(RAM-3) show?

A. Exhibit No.____(RAM-3), which is identical to Interim Rule 38.5.175, page 5 shows the calculation of the revenue deficiency of $1,686,101 based on the pro forma operating income and rate base and using the overall rate of return of 8.489 percent from Interim Statement F, page 1.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,791,481	**$3,455,478**	$61,246,959
Transportation	1,131,533		1,131,533
Other	416,112		416,112
Total Revenues	59,339,126	3,455,478	62,794,604
Operating Expenses			
Operation and Maintenance			
Cost of Gas	38,854,572		38,854,572
Other O&M	11,117,078		11,117,078
Total O&M	49,971,650		49,971,650
Depreciation	4,423,602		4,423,602
Taxes Other Than Income	3,275,499	11,058 2/	3,286,557
Current Income Taxes	(3,293,075)	1,356,672 2/	(1,936,403)
Deferred Income Taxes	3,334,426		3,334,426
Total Expenses	57,712,102	1,367,730	59,079,832
Operating Income	$1,627,024	$2,087,748	$3,714,772
Rate Base	$43,759,831		$43,759,831
Rate of Return	**3.718%**		**8.489%**

1/ See Rule 38.5.175, page 6.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of .12% and PSC tax of .20%.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION TAX
MONTANA CONSUMER COUNSEL TAX
CALCULATION OF UNDER RECOVERED BALANCE
OCTOBER 2010-JUNE 2012

		Tax Submitted 1/			Tax Recovered 2/		Diffference
Quarter Ending	Revenue	PSC	MCC	Total	Dk Sales 3/	Tax Collected 4/	(Over) Under
December 2010	$16,814,233	$70,620	$18,496	$89,116	2,422,805	$48,456	$40,660
March 2011	34,821,770	146,251	38,304	184,555	5,082,739	101,655	82,900
June	15,810,306	66,403	17,391	83,794	2,065,720	41,314	42,480
September	6,158,815	25,867	6,775	32,642	612,085	12,242	20,400
December	17,162,051	34,324	20,594	54,918	2,322,548	46,451	8,467
March 2012	26,702,963	53,406	32,044	85,450	4,070,500	81,410	4,040
June	9,221,861	18,444	11,066	29,510	1,427,460	28,549	961
	$126,691,999	$415,315	$144,670	$559,985	18,003,857	$360,077	$199,908

Under Recovery	$199,908
Firm Dk Sales 5/	9,911,287
Estimated recovery per dk	$0.020

1/ Combined tax rate of 0.53 percent for the period October 2010-September 2011 and 0.32 percent for the period October 2011-June 2012.
2/ Combined tax rate of 0.24 percent.
3/ Sales rates 60, 70 and 72.
4/ Reflects $.020 per dk embedded in firm rates resulting from Docket Nos. D2009.9.123 amd D2009.9.124.
5/ Pro forma annual firm sales volumes.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN - INTERIM
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,791,481	**$1,686,101**	$59,477,582
Transportation	1,131,533		1,131,533
Other	416,112		416,112
Total Revenues	59,339,126	1,686,101	61,025,227
Operating Expenses			
Operation and Maintenance			
Cost of Gas	38,854,572		38,854,572
Other O&M	11,005,742		11,005,742
Total O&M	49,860,314		49,860,314
Depreciation	3,020,432		3,020,432
Taxes Other Than Income	3,174,668	5,396 2/	3,180,064
Current Income Taxes	(1,533,883)	661,988 2/	(871,895)
Deferred Income Taxes	2,224,810		2,224,810
Total Expenses	56,746,341	667,384	57,413,725
Operating Income	$2,592,785	$1,018,717	$3,611,502
Rate Base	$42,543,312		$42,543,312
Rate of Return	**6.094%**		**8.489%**

1/ See Rule 38.5.175, page 1.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of .12% and PSC tax of .20%.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

In the Matter of the Application of	)	
MONTANA-DAKOTA UTILITIES CO.,	)	
a Division of MDU Resources Group,	)	Docket No. D2012.9.__
Inc., for Authority to Establish	)	
Increased Rates for Natural Gas	)	
Service		

DIRECT TESTIMONY AND EXHIBITS

OF

EARL M. ROBINSON

On The Subject of Depreciation

DEPRECIATION

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I. WITNESS INTRODUCTION

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

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

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

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

II. PURPOSE OF TESTIMONY

Q3. What is the purpose of your testimony?

A. The purpose of my testimony is to set forth the results of my depreciation review and analysis of the plant in service of Montana-Dakota Utilities Co.-Gas Division and Common Plant ("Company") which was conducted in the process of preparing depreciation studies of the Company's gas and common plant assets as of December 31, 2008. Reports of my review and analyses are contained in Exhibit No. ___(EMR-1), titled "Montana-Dakota Utilities Co-Gas Division Depreciation Study as of December 31, 2008" and Exhibit No____(EMR-2), the "Montana-Dakota Utilities Co-Common Plant Depreciation Study as of December 31, 2008". In preparing the report, I investigated and analyzed the Company's historical plant data and reviewed the Company's past experience and future expectations to determine the remaining lives of the Company's gas and common plant assets. The studies utilized the resulting remaining lives, the results of a salvage analysis, the Company's vintaged plant in service investment and depreciation reserve to develop recommended average remaining life depreciation rates and depreciation expense related to the Company's plant in service.

III. BACKGROUND

Q4. How is depreciation defined?

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

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

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

IV. DEPRECIATION STUDY OVERVIEW

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

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

Q7. What steps were involved in preparing the service life and salvage database that you utilized?

A. My comprehensive depreciation analyses included a detailed analysis of the Company's fixed capital books and records through December 31, 2008. The Company's historical investment cost records for each account have been assembled into a depreciation database upon which detailed service life and salvage analysis were performed using standard depreciation procedures.

Q8. What is the purpose of the historical database?

A. The historical service life and net salvage data is a basic depreciation study tool that is assembled to prepare a depreciation study. The historical database is used to make assessments and judgments concerning the service life and salvage factors that have actually been achieved, and (along with information relative to current and prospective factors) to determine the appropriate future lives over which to recover the Company's depreciable fixed capital investments. In accordance with this standard depreciation analysis, the Company's depreciation database compiled through December 31, 2008, which contains detailed vintage level information, was used to develop observed life tables. The development of the observed life tables from the historical information was completed by grouping like aged investments within each property category and identifying the level of retirements that occur through each successive age to develop the applicable observed life tables. The resulting observed lives were then fitted to standard Iowa Curves to estimate each property group's historically achieved average service life.

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

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

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

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

Each of the depreciation reports are divided into seven (7) sections. Section 1 of the report contains a brief narrative summary of the respective report. Two key portions of each of the reports are Sections 2 and 4. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property group and other depreciation rate development schedules. Section 4 contains a narrative description of the factors considered in selecting service life parameters for the Company's property. The various other sections of the report contain detailed information and/or documentation supporting the schedules contained in Sections 2 and 4. In addition, Section 5 is the graphical presentation of the average service life analysis, Section 6 is the detailed Average Remaining Life calculations, and Section 7 is detailed Net Salvage analysis schedules.

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

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

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

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

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

A. Yes. The Company maintains aged plant records. Therefore, the Retirement Rate Method was utilized in the depreciation studies of the Company's property.

V. METHODS, PROCUDURES & TECHNIQUES

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

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

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

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

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

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

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

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

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

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

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

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

Q16. Why did you utilize this method, procedure and technique?

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

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

Finally, the amount of annual depreciation must be based upon the productive life over which the un-depreciated capital investment is recovered (the Average Remaining Life Technique). The utilization of the Average Remaining Life Technique to develop the applicable annual depreciation expense (over the average remaining life) assures that the Company's property investment is fully recovered over the useful life of the property, and that inter-generational inequities are avoided as current and future customers will pay their fair share of depreciation expense. The determination of the productive remaining life for each property group relies on a study of both past experience and future expectations and develops the appropriate total life and applicable depreciation rates for each of the Company's property groups. The Average Remaining Life Technique incorporates all of the Company's fixed capital cost components, thereby better assuring full recovery of the Company's embedded net plant investment and related costs. The Average Remaining Life Technique gives consideration not only to the average service life and survival characteristics plus the net salvage component, but also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. The Average Remaining Life Technique is used by regulated companies and regulatory agencies because it allows full recovery by the end of the property's useful life -- no more and no less.

VI. GROUP DEPRECIATION

Q17. Please explain the utilization of group depreciation.

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

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

Q18. What factors influence the determination of the recommended annual depreciation rates included in your depreciation reports?

A. The depreciation rates reflect four principal factors: (1) the plant in service by vintage, (2) the book depreciation reserve, (3) the future net salvage, and (4) the composite remaining life for the property group. Factors considered in arriving at the service life are the average age, realized life and the survival characteristics of the property. The net salvage estimate is influenced by both past experience and future estimates of the cost of removal and gross salvage amounts.

Q19. Please explain further the assumptions considered when utilizing your depreciation approach.

A. According to my approach, the Company will recover its un-depreciated fixed capital investment through annual depreciation expense in each year throughout the useful life of the property. The Average Remaining Life Technique incorporates the future life expectancy of the property, the vintaged surviving plant in service, the survival characteristics, together with the book depreciation reserve balance and future net salvage in developing the amounts for each property account. Accordingly, Average Remaining Life depreciation meets the objective of providing a Straight Line recovery of the Company's fixed capital property investments.

Q20. Please explain further the group you have used.

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

VII. NET SALVAGE

Q21. What are the net salvage factors included in the determination of depreciation rates?

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

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

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

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

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

To provide further explanation of the issue, several general principles surrounding property retirements and related net salvage should be highlighted. As property continues to age, assets that typically generate positive salvage when retired will generate a lower percentage of positive salvage as compared to the original cost of the property. By comparison, if the class of assets is one that typically generates negative net salvage (cost of removal) with increasing age at retirement, the negative net salvage percentage as compared to original cost will typically be greater. This situation is routinely driven by the higher labor costs that occur with the passage of time.

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

(6) years. Car #1 generates 75% salvage or $15,000 when retired and Car #2 generates 5% salvage or $1,000 when retired.

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

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

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

VIII. DEPRECIATION STUDY ANALYSIS

Q22. Please explain what factors affect the length of the average service life that the Company's property may achieve.

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

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

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

Q23. What study procedures were utilized to determine service lives for the Company's property?

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

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

While a number of methods are available to study historical data, as I mentioned previously, the two methods most commonly utilized to determine average service lives for a company's property are the Retirement Rate Method and the Simulated Plant Record Method. Given that the Company does not have complete historical vintage based investment records, it was required that the Simulated Plant Record Method be used to analyze the past historical data. The Company is currently in the process of implementing a new property record system which will enable increased use of actuarial study analysis in future years.

Q24. Please explain further the use of the retirement rate method.

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

Q25. Do the depreciation study reports contain charts which compare the analysis of the Company's actual historical data to the service life parameters you are proposing as a basis for your recommended annual depreciation rates?

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

Q26. You have referred to the use of the Iowa or smoothed survivor curves. Can you generally describe these curves and their purpose?

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

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

Q27. What is the principal reason for completing the detailed historical life and salvage analysis?

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

IX. COMPREHENSIVE DEPRECIATION STUDY RESULTS AS OF 12-31-08

Q28. What is the basis for the Company's currently approved depreciation rates?

A. As shown in Exhibit No. ___(EMR-1), Table 1, pages 2-1 to 2-2, the prior depreciation rates for the plant were based upon depreciation parameters set forth in a study completed using the Company's plant investment data through December 31, 2001. The current account level depreciation rates composite to an annual depreciation rate of 3.85 percent when applied to each of the December 31, 2008 plant in service account balances.

Q29. What are the most notable changes in annual depreciation rates and expense between the present and proposed depreciation rates as set forth in Section 2 of the Montana-Dakota gas depreciation report?

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

The most notable depreciation/amortization occurred relative to Account 376 - Mains, Account 380 - Services, Account 391.1 - Office Furniture and Equipment, Account 391.5 - Computer Equipment - Other and Account 392.20 - Transportation Equipment - Cars & Trucks.

The proposed depreciation rate for Account 376 – Mains, increased from 1.92 percent to 2.97 percent. The proposed depreciation rate is the result of combined changes of both the average service life and net salvage parameters for the various property categories that comprise the overall plant account. Based upon the Company's actual historical plant in service data individual service life parameters were estimated for each of the primary property groups (including Steel, Plastic, Valves, Manholes, and Bridge and River Crossings) as outlined in section 4 of the depreciation study report. The proposed average service life for each sub property group was changed in accordance with the life indication developed through an analysis of the Company's historical data and consideration of future expectations. The resulting proposed composite average service life of the various property groups is forty-seven (47) years, while the average service life underlying the present depreciation rate is an implicit forty-five (45) years. The future net salvage underlying the proposed depreciation rates is negative 50 percent while the future net salvage underlying the present depreciation rates is negative 60 percent. Notwithstanding the fact that both the estimated average service life was lengthened and the negative net salvage was reduced in developing the proposed depreciation rate, the resulting rate increased. Accordingly, the ARL depreciation rate increase is being driven by the fact that the current book depreciation reserve is at a lower level than required relative to the estimated depreciation parameters and currently average age of the property groups.

The proposed depreciation rate for Account 380 – Services, increased from 5.66 percent to 8.18 percent. The proposed depreciation rate is the result of combined changes of both the average service life and net salvage parameters for the various property categories that comprise the overall plant account. Based upon the Company's actual historical plant in service data individual service life parameters were estimated for each of the primary property groups (including Steel, Plastic, and Farm and Fuel Lines) as outlined in section 4 of the depreciation study report. The proposed average service life for each sub property group was changed in accordance with the life indication developed through an analysis of the Company's historical data and consideration of future expectations. The resulting proposed composite average service life of the various property groups is an implicit forty (40) years, which is the same forty (40) year implicit average service life underlying the present implicit depreciation rate. The future net salvage underlying the proposed depreciation rates is negative two hundred (200) percent while the future net salvage underlying the present depreciation rates is negative one hundred seventy five (175) percent and is reflective of the increased level of negative net salvage being experienced by the company.

The depreciation rate relative to Account 392.20 - Transportation Equipment - Cars & Trucks decreased from 21.13 percent to 0.00 percent. The current estimated average service life is 7 years and the net salvage factor is estimated at 15 percent. The depreciation rate decrease is the product of the fact that the current plant in service investment is fully depreciated. Given the typical shorter average service life experienced by this property class, the depreciable life, net salvage rate and resulting annual depreciation rate requires more frequent review than has previously occurred. To the extent that significant retirements of existing property investments and additions of new property investments occur in the coming intervening years (and the current fully depreciated status of the property group declines significantly) a depreciation rate of 12.14 percent (based upon the 7 year average service life and 15 percent net salvage) should be utilized until the next depreciation study is performed.

Q30. What is the net change to the composite depreciation rate under the proposed depreciation rates in comparison to December 31, 2008 present depreciation rates?

A. Application of the proposed account level depreciation rates to the Company's plant in service as of December 31, 2008 produces a composite depreciation rate of 4.06 percent. By comparison the application of the December 31, 2008 then currently utilized account level depreciation rates to the Company's plant in service as of December 31, 2008 produces a composite depreciation rate of 3.85 percent.

Q31. What is the net change in annual depreciation expense under the proposed depreciation rates in comparison to present December 31, 2008 depreciation rates?

A. Exhibit No.___(EMR-1), Section 2, Table 1, pages 2-1 to 2-2 indicates a net increase in annualized depreciation expense of $525,793 in comparison to the depreciation expense produced by the then current depreciation rates, when applied to the Company's plant in service investment as of December 31, 2008.

X. NET CHANGE FROM 12-31-11 BOOK DEPRECIATION RATES TO PROPOSED DEPRECIATION RATES FROM 12-31-2008 STUDY

Q32. Are there updates that need be incorporated into the proposed account level depreciation rates set forth in the December 31, 2008 depreciation study?

A. Yes, in the December 31, 2008 depreciation study the Company did not have investments in Account 333-Field Compressor Station Equipment.

Since that period of time, the Company has invested approximately $10 million in equipment contained in this property account. Subsequent to the placement of the property and related investment, the Company implemented a book depreciation rate of 3.33% for this property group.

Also, at the time of the completion of the December 31, 2008 depreciation study Account 392.2-Transportation Equipment was fully accrued, which resulted in a then proposed depreciation rate of 0.0%. Since that time the Company has added and retired various items of plant in the property account. As of December 31, 2010, calculations were completed and the Company adjusted it book depreciation rate to 0.26%. With the passage of time, changes will continue to occur in the property account. Accordingly, due the nature of this type of plant, the Company will recalculate the depreciation rate on a more frequent basis.

Q33. Have you prepared an exhibit which compares the composite depreciation rate under current book depreciation rates versus the account level deprecation rates from the December 31, 2008 depreciation study when applied to the Company's December 31, 2011 plant in service balances?

A. Yes, that information is contained on Exhibit No.___(EMR-3).

Q34. What is the net change to the Company's composite depreciation rate under the proposed December 31, 2008 depreciation study rates in comparison to present book depreciation rates when applied plant in service as of December 31, 2011?

A. Exhibit No. ___(EMR-3) shows the application of the proposed December 31, 2008 depreciation study account level depreciation rates to the Company's plant in service as of December 31, 2011, which, as shown on page 2 of the exhibit, produces a composite depreciation rate of 4.16 percent. By comparison, the application of the pre-2008 depreciation rates (Column D) to the Company's plant in service as of December 31, 2011 produces a composite depreciation rate of 3.12 percent, or an increase in the composite rate for Montana-Dakota of 1.04 percent based on 2011 levels.

XI. RECOMMENDATION

Q35. What is your recommendation in this proceeding?

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

Q36. Does this conclude your direct testimony?

A. Yes, it does.

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

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

EXPERIENCE

1977 to Date

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

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

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

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

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

**PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS**

the past twenty (20) plus year period.

He is also responsible for developing and publishing the firm's AUS Telephone Plant Index (successor to the Handy Whitman and C A Turner Telephone Construction Cost Index), a reproduction cost index subscribed to by various operating companies, regulatory agencies, and consultants.

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

1975 to 1977

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

1971 to 1975

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

1966 to 1971

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

TESTIMONY

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

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

PERSONAL

Education:

Graduate of Harrisburg Area Community College with an Associate of Arts Degree in Accounting, and has undertaken further studies at University Center of Harrisburg. Successfully completed numerous programs related to service life and salvage estimation, forecasting, and evaluation sponsored by Depreciation Programs, Inc. at Calvin College Campus, Grand Rapids, Michigan. In addition, Mr. Robinson successfully completed cost of service seminars sponsored by the American Water Works Association. He received his CDP (Certified Depreciation Professional) designation by Exam during 1996.

List of Clients Served

CATV

Storer Broadcasting Company
(DE, MD, MN)
Cable Television Consortium

ELECTRIC

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

GAS

ATCO Gas
ATCO Pipelines
Atlanta Gas Light Company
Bay State Gas Company
C & T Enterprises, Inc.
Valley Cities Waverly Gas Company
Canadian Western Natural
Gas Company Limited
Cascade Natural Gas Corporation
Citizens Gas & Coke Utility
North Carolina Gas Service
North Penn Gas
Northern Indiana Public Service Co.
Northern Utilities, Inc.-Maine
Northern Utilities, Inc.-New Hampshire
Oklahoma Natural Gas Company
Pacific Gas & Electric Company
Paiute Pipeline
Pennsylvania Gas & Water Company
PG Energy Inc.

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Columbia Gas of Pennsylvania, Inc.
Connecticut Natural Gas Corporation
Consolidated Edison Co of New York
East Ohio Gas
  Elkton Gas Service
Granite State Gas Transmission, Inc.
Great Plains Natural Gas Co.
Kansas Gas Service
Louisville Gas & Electric Co. - Gas Division
Montana Dakota Utilities - Gas Division
National Fuel Gas Distr. Corp., NY
National Fuel Gas Supply
New York State Electric & Gas Corp
NICOR Gas Company
Northeast Heat & Light Company
Pennsylvania and Southern Gas Company
  Valley Cities Division
  Waverly Division
Pipeline Industry Group
Providence Gas Company
Public Service Electric & Gas Co
Public Service Company of New Mexico
Roanoke Gas Company
Rochester Gas and Electric Corporation
Saxonburg Heat & Light Company
Southern Connecticut Gas Company
Southwest Gas Corporation
T.W. Phillips Gas & Oil Company
Williams Companies

GENERAL CLIENTS

Arthur Andersen
Pricewaterhouse Coopers
Ernst & Young
Standard & Poors

REGULATORY AND GOVERNMENTAL

Regulatory Commission of Alaska
  Alaska Electric Light & Power Company
  Interior Telephone Company, Inc
  Fairbanks Water & Wastewater
  Mukluk Telephone Company, Inc
  TDX North Slope Generating
  United KUC, Inc
  United Utilities, Inc.
Arizona Corporation Commission
  Mountain States Telephone & Telegraph
  Southwest Gas Corporation
Baltimore County, MD
Bensalem Township - Water
Bethlehem Authority - Water
Borough of Butler, NJ
Borough of Media Water Works
City of New Orleans, LA
Delaware Public Service Commission
Delaware River Port Authority
Diamond State Telephone Company
Kansas Corporation Commission
  Southwest Bell
Public Service Comm. of Nevada
  Nevada Bell
Town of Waterford, CT
  Northeast Utilities
Washington, D.C. - PSC
  C&P Telephone Company
  Potomac Electric Power Company

TELECOMMUNICATIONS

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

PROFESSIONAL QUALIFICATIONS
OF
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Cellular Industry Study Group
AT&T Wireless
BellSouth Communications
GTE Mobilnet
Brighthouse Networks-Citrus County
Cable & Wireless
Chenango & Unadilla Telephone Company
Cingular Wireless
Cingular Wireless – California
Cingular Wireless – Houston
Cingular Wireless - Massachusetts
Commonwealth Telephone Company
CTC of Michigan
CTC of Virginia
Denver & Ephrata Telephone & Telegraph Co.
D & E Network
D & E System
Embarq Florida, Inc.
Empire Telephone Corporation
Illinois Consolidated Telephone Co.
Jamestown Telephone Corporation
Leesport Telephone Company
Lewisberry Telephone Company
Los Angeles Cellular Telephone Co.
MCI International, Inc.
MCI Telecommunications Corp.
MFS Communication Company, Inc.
Marianna & Scenery Hill Tel. Co.
Mid State Telephone Company
Motorola, Inc.
Nevada Bell
New Jersey Telephone Company
The North-Eastern Pennsylvania Tel. Co.
Pacific Bell
Pactel Cellular
Quaker State Telephone Company
Qwest Communications Corporation
Qwest – Arizona
Qwest – Iowa
Qwest -- Montana
Qwest -- Washington
RCA Global Communications, Inc.
SBC Ameritech Corporation
SBC -- Arkansas
SBC -- Kansas
SBC -- Michigan
SBC -- Missouri
SBC -- Ohio
SBC -- Oklahoma
SBC – Wisconsin
SBC – West – California
SBC – West – Nevada
Southwestern Bell Telephone Company
Standard Telephone Company
Telecommunications d'Haiti
Telephone Utilities of Pennsylvania
United Telephone Company of New Jersey
Verizon Wireless
Verizon – California
Verizon – Kentucky
Verizon – Massachusetts
Verizon -- Montana
Verizon – South Carolina
Verizon -- Utah
Verizon -- Washington
Verizon – Wyoming
Verizon – Total Company
Virgin Islands Telephone Corporation
Williams Communication
WilTel, Inc.

WATER

Artesian Water Company
City of Auburn
Bethlehem Authority - Water
California Water Service Company
California-American Water Company
Citizens Water - California
Citizens Water - Arizona
Clinton Water Company
Columbia Water Company
Commonwealth Water Company
Consumers New Jersey Water Company
Dauphin Consolidated Water Supply Co.
Dominguez Water Company
Elizabethville Water Company
City of Fairfax
Garden State Water Company
New Mexico-American Water Company, Inc.
Newtown Artesian Water Company
New York-American Water Company
Ohio-American Water Company
Palm Coast Utility Corporation
Pennichuck East Utility
Pennichuck Water Works
Pennsylvania-American Water Company
Pennsylvania Gas and Water Company
Pennsylvania Water Company
Erie & Sayre Divisions
Philadelphia Suburban Water Company
Pinelands Water Company
Public Service Water Company
Riverton Consolidated Water Company
Roaring Creek Water Company

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
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Hackensack Water Company
Hershey Water Company
Illinois-American Water Company
Indian Rock Water Company
Indianapolis Water Company
Iowa-American Water Company
Keystone Water Company
Manufacturers Water Company
Masury Water Company
Middlesex Water Company
Monarch Utilities, Inc
Monmouth Consolidated Water Company
New Haven Water Company
New Jersey Water Company
Rock Springs Water Company
Shenango Valley Water Company
Southern California Water Company
Spring Valley Water Company
Tidewater Utilities, Inc.
United Water - Delaware
United Water - Toms River
United Water - New Jersey
United Water - Pennsylvania
United Water - Virginia
Virginia American Water Company
Western Pennsylvania Water Company
York Water Company

STEAM

Consolidated Edison Co of New York

WASTEWATER

California - American Water Company
Citizens Sewer – Arizona
Illinois-American Company – Wastewater
Monarch Utilities, Inc
New Jersey Water Company
Sewer Districts
Palm Coast Utility Corporation
Pinelands Sewer Company
Wynnewood Sewer Company

PROFESSIONAL QUALIFICATIONS

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

PROFESSIONAL AFFILIATIONS

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

PUBLICATIONS

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

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

SPEECHES AND PRESENTATIONS

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

**PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

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

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

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

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

**PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS**

Jurisdiction	Client	Docket/Application	Subject
	Delaware Public Service Comm./ Diamond State Telephone Co.	81-8	P.I.S. Measures of Value and Depreciation
	Delmarva Power & Light Company	05-304	Depreciation
	Tidewater Utilities, Inc/ Public Water and Supply, Inc	99-466	Depreciation
District of Columbia	Potomac Electric Power Co.	F.C. 869	Depreciation
	Washington, DC PSC/C&P Tel Corp.	F.C. 777	Depreciation
	Washington, DC PSC/ Potomac Electric Power Co.	F.C. 785 F.C. 813	Capital Recovery/ Depreciation
FERC	Granite State Gas Transmission, Inc.	RP91-164-000	Depreciation
	Paiute Pipeline	RP96-306-000	Depreciation
	Public Service Company of NM	ER-11-1915-000	Depreciation
Florida (County of Duval)	BellSouth Telecommunications	Petitions 1795-1800	Replacement Cost/ Depr. Repl. Cos
(County of Lee)	Sprint-Florida, Inc (Embarq)	Case No. 02-CA-013330-1	Replacement Cost
(County of St. Lucie)	BellSouth Telecommunications	1999 Petitions	Replacement Cost/ Depr. Repl. Cost
(County of Citrus)	Embarq	Case No. 2003-CA4473, 2004-CA4565, 2005-CA5010	Property Tax Valuation Deposition
(County of Lee)	Embarq	Case No. 02-13330 CA-WCM	Property Tax Valuation Deposition
	Progress Energy – Florida Progress Energy – Florida	050078-EI 090079-EI	Depreciation Depreciation
Illinois	Illinois - American Water Company	00-0340 02-0690 07-0507	Depreciation Depreciation Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
	Illinois Consolidated Telephone Co.	81-0264 82-0623	RCN/RCND * RCN/RCND *
Indiana	Northern Indiana Public Service Company	Cause No. 41746	Depreciation
Iowa (Dept of Rev)	Qwest Corporation-Iowa	883	Property Tax Valuation Deposition
Kansas	Kansas Gas Service	03-KGSG-602-RTS	Depreciation
Kentucky	Kentucky Utilities	Case No. 2003-00434	Depreciation
	Louisville Gas & Electric Electric Gas	Case No. 2003-00433	Depreciation
Maryland	Delmarva Power & Light Company	9093	Depreciation
	Potomac Electric Power Company	9092	Depreciation
Massachusetts	Bay State Gas Company	92-111 DTE 05-27	Depreciation Depreciation
Montana	Montana-Dakota Utilities Co-Elec	Docket # 2007.7.79 Docket # 2010.8.82	Depreciation Depreciation
	Qwest Corporation-Montana	06DORFC001 06DOTFC017	Property Tax Valuation Deposition
Nevada	Southwest Gas Corporation	04-3011	Depreciation
New Jersey	Atlantic City Electric d/b/a Conectiv Power Delivery	ER03020110	Depreciation
	Borough of Butler/ Butler Elec. Dept.	792-84	Valuation of Plant in Service Customer Revenue and Purchase Power
	Commonwealth Water Co.	842-100	Depreciation
	Consumers NJ Water Company	WR00030174	Depreciation
	Garden State Water Co.	WR91091483	Depreciation
	Middlesex Water Company	WR8602-240 WR90080884J WR96110818	Depreciation Depreciation Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction	Client	Docket/Application	Subject
	Monmouth Cons. Water Co.	8312-1113	Depreciation
	New Jersey Water Company	834-292	Depreciation
	Public Service Electric & Gas	GR05100845	Depreciation
	United Water Resources (formerly Hackensack Water Co.)	8506-663 WR90080792J WR95070303	Depreciation Depreciation Depreciation
	Toms River Water Company	WR95050219	Depreciation
New Hampshire	Northern Utilities, Inc.	DR91-081	Depreciation
New Mexico	New-Mexico American Water Company, Inc.	2813 03-00206-UT	Depreciation Depreciation
	Public Service Company of NM	08-00273-UT 10-00086-UT	Depreciation Depreciation
New York	New York-American Water Co.	28911	Depreciation
	New York State Elec. & Gas Corp. Electric Business & Common Plant	05-E-1222	Depreciation
	New York State Elec. & Gas Corp-Elec.	09-E-0715	Depreciation
	New York State Elec. & Gas Corp-Gas	09-G-0716	Depreciation
	Rochester Gas and Elec. Corp-Elec.	09-E-0717	Depreciation
	Rochester Gas and Elec. Corp-Gas	09-G-0718	Depreciation
	Spring Valley Water Co., Inc.	89-W-1151 92-W-0645	Depreciation Depreciation
North Carolina	Nantahala Power and Light Co.	E-13, SUB157	Depreciation
North Dakota	Montana-Dakota Utilities Co-Gas	Case No. PU-399-02-183	Depreciation
Oklahoma (State Board of Equalization)	SWBT-Oklahoma	EQ-2004-10	Property Tax Valuation Deposition
Pennsylvania	Borough of Media Water Works	R-912150	Depreciation
	Columbia Gas of Penna.	R-80031129	Depreciation and Valuation

**PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS**

Jurisdiction	Client	Docket/Application	Subject
	Commonwealth Telephone Co.	I-00920020	Depreciation
	Keystone Water Company	R-842755 R-842756 R-842759	Capital Recovery/Depreciation Capital Recovery/Depreciation Capital Recovery/Depreciation
	Mid Penn Tel. Corp.	R-80071264	Depreciation
	Penna.-American Water Co.	R-891208	Depreciation
	Penna. Gas & Water Co. - Gas Division	R-821961 R-832475	Depreciation Depreciation
	Penna. Gas & Water Co. - Water Division	R-822102 R-850178 R-870853	Depreciation Capital Recovery/Depreciation Capital Recovery/Depreciation
	Penna. Gas & Water Co. - Scranton Division	R-901726	PIS Meas. of Value/Depreciation
		R-922482	Depreciation
	Penna. Gas & Water Co. - Spring Brook Division Nesbitt Service Area	R-911966	PIS Meas. of Value/Depreciation
	Crystal Lake Service Area	R-922404	PIS Meas. of Value/Depreciation
	Ceasetown/Watres Service Area	R-93266	Depreciation
	Penna. Power Company	R-811510	PIS Meas. of Value/Depreciation
		R-821918	PIS Meas. of Value/Depreciation
		R-832409	PIS Meas. of Value/Depreciation
		R-842740	PIS Meas. of Value/Depreciation
		R-850267	PIS Meas. of Value/Depreciation
		R-870732	PIS Meas. of Value/Depreciation
	Pennsylvania & Southern Gas Company	R-870686	Depreciation
	PG Energy Inc.	R-963612 R-984280 R-00061365	PIS Meas. Of Value/Depr PIS Meas. Of Value/Depr PIS Meas. OFValue/Depr
	Philadelphia Suburban Water Company	R-911892	Depreciation
		R-922476	PIS Meas. of Value/Depreciation
		R-932868	PIS Meas. of Value/Depreciation

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Jurisdiction		Client	Docket/Application Subject
	Riverton Consolidated Water Co.	R-842675	Capital Recovery/Depreciation
	United Water - Pennsylvania	R-00973947	Depreciation
	Western Pennsylvania Water Company	R-842621	Capital Recovery/Depreciation
		R-842622	Capital Recovery/Depreciation
		R-842623	Capital Recovery/Depreciation
		R-842624	Capital Recovery/Depreciation
		R-842625	Capital Recovery/Depreciation
	Wellsboro Electric Company	R-00016356	Depreciation
Rhode Island	Providence Gas Company	1914	Depreciation
		2286	Depreciation
South Carolina	Lockhart Power Company	87-435-E	Depreciation
Tennessee (Board of Equalization)	Bellsouth – Tennessee	67-5-903	Property Tax Valuation Deposition
Utah	Verizon Wireless	05-0826, 05-0829	Property Tax Valuation Deposition & Hearing
Virgin Islands	Virgin Islands Tel. Corp.	264	Depreciation
		314	Depreciation
		316	Depreciation

* Reproduction Cost New/Reproduction Cost New Depreciated.

Table 1

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2011 and Related Annual Depreciation Expense Under 12-31-08 Present and Proposed Rates (Except Accounts 333 & 392.20)

Account No. (a)	Description (b)	Original Cost 12/31/11 (c)	Present Book Rates Rate % (d)	Present Book Rates Annual Accrual (e)	Proposed Rates: Proposed Plant Only Rates Rate % (f)	Proposed Plant Only Rates Annual Accrual (g)	Proposed Gross Salv Rates Rate % (h)	Proposed Gross Salv Rates Annual Accrual (i)	Proposed COR Rates Rate % (j)	Proposed COR Rates Annual Accrual (k)	Total Proposed Rates Rate % (l)	Total Proposed Rates Annual Accrual (m)	Net Change Depr.. Exp. (n)
	DEPRECIABLE PLANT												
	Production & Gathering Plant												
333.00	Field Compressor Station Equip.	10,778,166.68	3.33%	358,912.95	3.33%	358,912.95	0.00%	0.00	0.00%	0.00	3.33%	358,912.95	0.00
	TOTAL Production & Gathering Plant	10,778,166.68	3.33%	358,912.95	3.33%	358,912.95	0.00%	0.00	0.00%	0.00	3.33%	358,912.95	0.00
	Distribution Plant												
374.20	Rights of Way	367,926.43	1.39%	5,114.18	1.39%	5,114.18	0.00%	0.00	0.00%	0.00	1.39%	5,114.18	0.00
375.00	Distr. Meas & Reg Station Structures	655,599.82	1.81%	11,866.36	1.52%	9,965.12	0.18%	1,180.08	1.07%	7,014.92	2.77%	18,160.12	6,293.76
	Mains												
376.10	Mains-Steel		2.08%	0.00	1.77%	0.00	0.00%	0.00	1.07%	0.00	2.84%	0.00	0.00
376.20	Mains-Plastic		2.08%	0.00	1.99%	0.00	0.00%	0.00	1.06%	0.00	3.05%	0.00	0.00
376.30	Mains-Valves		2.08%	0.00	2.29%	0.00	0.00%	0.00	1.25%	0.00	3.54%	0.00	0.00
376.40	Mains-Manholes		2.08%	0.00	1.83%	0.00	0.00%	0.00	1.06%	0.00	2.89%	0.00	0.00
376.50	Mains-Bridge & River Crossings		2.08%	0.00	2.06%	0.00	0.00%	0.00	1.07%	0.00	3.13%	0.00	0.00
	Total Mains	119,706,390.10	2.08%	2,489,892.91	1.90%	2,279,709.22	0.00%	0.00	1.06%	1,274,566.06	2.97%	3,554,275.28	1,064,382.36
378.00	Meas & Reg Station Equip-General	2,408,361.07	3.29%	79,235.08	2.22%	53,465.62	0.00%	0.00	0.92%	22,156.92	3.14%	75,622.54	(3,612.54)
379.00	Meas & Reg Station Equip-City Gate	1,701,124.30	2.81%	47,801.59	2.81%	47,801.59	0.00%	0.00	0.94%	15,990.57	3.75%	63,792.16	15,990.57
	Services												
380.10	Services-Steel		5.75%	0.00	2.48%	0.00	0.00%	0.00	7.17%	0.00	9.65%	0.00	0.00
380.20	Services-Plastic		5.75%	0.00	2.50%	0.00	0.00%	0.00	5.41%	0.00	7.91%	0.00	0.00
380.30	Farm & Fuel Lines		5.75%	0.00	3.34%	0.00	0.00%	0.00	7.67%	0.00	11.01%	0.00	0.00
	Total Services	61,760,842.19	5.75%	3,551,248.43	2.50%	1,544,797.66	0.00%	0.00	5.68%	3,505,843.56	8.18%	5,050,641.23	1,499,392.80
381.00	Meters	58,285,743.59	2.81%	1,637,829.39	2.91%	1,696,115.14	0.00%	0.00	0.62%	361,371.61	3.53%	2,057,486.75	419,657.35
383.00	Service Regulators	6,665,638.48	1.57%	104,650.52	2.16%	143,977.79	-0.39%	-25,995.99	0.00%	0.00	1.77%	117,981.80	13,331.28
385.00	Industrial Meas. & Reg. Station Equip	786,434.70	2.43%	19,110.36	2.43%	19,110.36	0.35%	2,752.52	0.53%	4,168.10	3.31%	26,030.99	6,920.63
	MISCELLANEOUS EQUIPMENT												
386.10	Misc Property on Customers Premise	1,679.84	2.39%	40.15	2.39%	40.15	0.00%	0.00	0.00%	0.00	2.39%	40.15	0.00
386.20	CNG Refueling station	261,880.34	0.27%	707.08	0.27%	707.08	0.00%	0.00	0.00%	0.00	0.27%	707.08	0.00
386.30	CNG Lease/Demo												
	TOTAL Account 386	263,560.18	0.28%	747.23	0.28%	747.23	0.00%	0.00	0.00%	0.00	0.28%	747.23	0.00

Table 1

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2011
and Related Annual Depreciation Expense Under 12-31-08 Present and Proposed Rates (Except Accounts 333 & 392.20)

			Present Book Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Rates: Proposed Gross Salv Rates		Proposed Rates: Proposed COR Rates		Proposed Rates: Total Proposed Rates		
Account No.	Description	Original Cost 12/31/11	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Net Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	OTHER EQUIPMENT												
387.10	Cathodic Protection Equipment	2,406,620.03	3.21%	77,252.50	3.21%	77,252.50	0.00%	0.00	0.00%	0.00	3.21%	77,252.50	0.00
387.20	Other Distribution Equipment	587,151.32	0.99%	5,812.80	0.99%	5,812.80	0.00%	0.00	0.00%	0.00	0.99%	5,812.80	0.00
	TOTAL Account 387	2,993,771.35	2.77%	83,065.30	2.77%	83,065.30	0.00%	0.00	0.00%	0.00	2.77%	83,065.30	0.00
	TOTAL Distribution Plant	255,595,392.21	3.14%	8,030,561.35	2.30%	5,883,869.20	-0.01%	(22,063.39)	2.03%	5,191,111.75	4.32%	11,052,917.56	3,022,356.20
	General Plant												
390.00	General Structures	8,599,225.65	3.09%	265,716.07	3.09%	265,716.07	-0.04%	-3,439.69	0.41%	35,256.83	3.46%	297,533.21	31,817.13
	OFFICE FURNITURE & EQUIPMENT												
391.10	Office Furniture & Equipment	355,712.70	4.97%	17,678.92	6.59%	23,447.73	0.00%	0.00	0.00%	0.00	6.59%	23,447.73	5,768.81
391.30	Computer Equipment - PC	463,672.83	26.02%	120,647.67	11.28%	52,286.49	0.00%	0.00	0.00%	0.00	11.28%	52,286.49	(68,361.18)
391.50	Other Computer Equipment	54,035.44	0.00%	0.00	4.97%	2,683.89	0.00%	0.00	0.00%	0.00	4.97%	2,683.89	2,683.89
	TOTAL Account 391	873,420.97	15.84%	138,326.59	8.98%	78,418.11	0.00%	0.00	0.00%	0.00	14.14%	123,463.20	(59,908.48)
	TRANSPORTATION EQUIPMENT												
392.10	Transportation Equipment (Trailers)	447,872.48	9.67%	43,309.27	12.35%	55,312.25	-2.68%	-12,002.98	0.00%	0.00	9.67%	43,309.27	0.00
392.20	Trans Equipment (Cars & Trucks)	7,955,254.31	0.26%	20,683.66	1.04%	82,734.64	0.00%	0.00	0.00%	0.00	1.04%	82,734.64	62,050.98
	TOTAL Account 392	8,403,126.79	0.76%	63,992.93	1.64%	138,046.90	-0.14%	(12,002.98)	0.00%	0.00	1.50%	126,043.91	62,050.98
393.00	Stores Equipment	63,604.67	2.49%	1,583.76	2.44%	1,550.00	0.00%	0.00	0.00%	0.00	2.44%	1,550.00	(78.70)
	TOOLS, SHOP & GARAGE EQ.												
394.10	Tools, Shop & Garage Equip. (Non-Ui	2,091,733.29	6.62%	138,472.74	5.65%	118,162.30	0.00%	0.00	0.00%	0.00	5.65%	118,162.30	(20,310.45)
394.30	Vehicle Maintenance Equipment	37,100.02	5.78%	2,144.38	7.12%	2,640.27	0.00%	0.00	0.00%	0.00	7.12%	2,640.27	495.89
394.40	Vehicle Refueling Equipment	12,444.04	4.72%	587.36	10.32%	1,284.61	0.00%	0.00	0.00%	0.00	10.32%	1,284.61	697.25
	TOTAL Account 394	2,141,277.35	6.59%	141,204.48	5.70%	122,087.17	0.00%	0.00	0.00%	0.00	5.70%	122,087.17	(19,117.31)
395.00	Laboratory Equipment	217,351.36	7.67%	16,670.85	6.95%	15,113.85	0.00%	0.00	0.00%	0.00	6.95%	15,113.85	(1,557.00)
	POWER OPERATED EQUIPMENT												
396.10	Work Equipment (Trailers)	569,975.26	6.02%	34,312.51	10.19%	58,080.48	-4.17%	-23,767.97	0.00%	0.00	6.02%	34,312.51	0.00
396.20	Power Operated Equipment	6,998,028.24	0.95%	66,481.27	31.72%	2,219,774.56	-30.77%	-2,153,293.29	0.00%	0.00	0.95%	66,481.27	0.00
	TOTAL Account 396	7,568,003.50	1.33%	100,793.78	30.10%	2,277,855.04	-28.77%	(2,177,061.26)	0.00%	0.00	1.33%	100,793.78	0.00

Docket No. ______
Exhibit No. ______(EMR-3)
Page 3 of 3

Table 1

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2011
and Related Annual Depreciation Expense Under 12-31-08 Present and Proposed Rates (Except Accounts 333 & 392.20)

Account No. (a)	Description (b)	Original Cost 12/31/11 (c)	Present Book Rates Rate % (d)	Present Book Rates Annual Accrual (e)	Proposed Rates: Proposed Plant Only Rates Rate % (f)	Proposed Plant Only Rates Annual Accrual (g)	Proposed Gross Salv Rates Rate % (h)	Proposed Gross Salv Rates Annual Accrual (i)	Proposed COR Rates Rate % (j)	Proposed COR Rates Annual Accrual (k)	Total Proposed Rates Rate % (l)	Total Proposed Rates Annual Accrual (m)	Net Change Depr.. Exp. (n)
	COMMUNICATION EQUIPMENT												
397.10	Radio Communication Equip. (Fixed)	530,130.48	7.37%	39,070.62	6.07%	32,165.58	0.00%	0.00	0.00%	0.00	6.07%	32,165.58	(6,905.04)
397.20	Radio Communication Equip. (Mobile)	389,337.39	7.34%	28,577.36	4.06%	15,820.46	0.00%	0.00	0.00%	0.00	4.06%	15,820.46	(12,756.91)
397.30	General Telephone Communication E	60,470.40	9.88%	5,974.48	10.69%	6,465.81	0.00%	0.00	0.00%	0.00	10.69%	6,465.81	491.34
397.80	Network Equipment	137,334.06	26.26%	36,063.92	17.68%	24,280.34	0.00%	0.00	0.00%	0.00	17.68%	24,280.34	(11,783.59)
	TOTAL Account 397	1,117,272.33	9.82%	109,686.38	7.05%	78,732.19	0.00%	0.00	0.00%	0.00	7.05%	78,732.19	(30,954.19)
398.00	Miscellaneous Equipment	59,131.90	1.27%	750.98	9.43%	5,576.59	0.00%	0.00	0.00%	0.00	9.43%	5,576.59	4,825.61
	Sub-Total (General Plant) Amortizatio	**4,472,058.58**	9.13%	**408,223.04**	6.74%	**301,477.91**	0.00%	**0.00**	0.00%	**0.00**	7.75%	**346,523.00**	**(106,790.06)**
	TOTAL General Plant	29,042,414.52	2.89%	838,725.82	10.27%	2,983,095.92	-7.55%	(2,192,503.93)	0.12%	35,256.83	3.00%	870,893.90	(12,921.95)
	TOTAL Depreciable Plant	295,415,973.41	3.12%	9,228,200.12	3.12%	9,225,878.07	-0.75%	-2,214,567.32	1.77%	5,226,368.57	4.16%	12,282,724.41	3,009,434.26
	NON-DEPRECIABLE PLANT												
374.1	Land (Distribution)	276,933.70											
389	Land & Land Rights (General)	1,484,244.41											
	Total Land	1,761,178.11											
	INTANGIBLE PLANT												
303	Miscellaneous Intangible Plant	2,660,120.02											
	Total Intangible Plant	2,660,120.02											
	TOTAL Non-Depreciable Plant	4,421,298.13											
	TOTAL Plant in Service	299,837,271.54											
339	ARO-Production & Gathering	98,285.22											
388	ARO-Distribution	115,629.38											
		300,051,186.14											

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

Before the Public Service Commission of Montana

Docket No. D2012.9._____

Direct Testimony
of
Tamie A. Aberle

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

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

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

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

Q. What are your responsibilities as the Director of Regulatory Affairs?

A. My responsibilities include the preparation of rate design and miscellaneous tariff revision filings to ensure that the applicable revenue requirements are properly recovered from various customer classes via applicable rate forms. I also administer utility tariffs and rules and regulations effective in each of the jurisdictions in which Montana-Dakota provides utility service.

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

A. I graduated from Moorhead State University, Moorhead, Minnesota in 1982 with a Bachelor of Science degree in Accounting. I began my career with Montana-Dakota in 1983 in the Regulatory Affairs Department, holding several positions within the Department including Rate Administration Supervisor, Pricing and Tariff Manager and Regulatory Affairs Manager before attaining my current position in 2012.

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

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of North Dakota and Wyoming, and the Public Utilities Commissions of Minnesota and South Dakota.

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

A. The purpose of my testimony is to present the results of the embedded and marginal class cost of service studies, address the proposed recovery of the revenue requirement identified by Ms. Mulkern in her direct testimony on each of the Company's gas rates, including how the distribution of the revenue requirement was made among the various classes of customers served, and introduce a proposed Distribution Delivery Stabilization Mechanism designed to normalize the distribution portion of customers' bills. In addition, my testimony will discuss the extent to which Montana-Dakota is proposing changes in rate design and/or tariff conditions.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Page 7 of Statement H, Statement L, Statement M, Part B of Statement O and Exhibit No. __ (TAA-1) through Exhibit No. ___ (TAA-6). I also sponsor the proposed rate schedules to be effective on a final basis and the proposed interim rate schedules appended to the Application for Interim Rate Relief.

Q. What is the total revenue effect of the proposed gas rate changes?

A. The proposed interim rates will produce additional revenues of $1,686,422 or 2.9% annually based on the interim level of test period sales, while the final proposed rates will produce additional revenues of $3,457,412 or 5.9% annually based on pro forma 2012 throughput. Exhibit No. __ (TAA-1) represents summaries by rate classification of the proposed interim and final revenue increase on pages 1 and 2 respectively. The exhibit shows the rate number and a description along with the revenues calculated under the present and proposed rates. The amount and percentage increase is also shown for the proposed revenue increase. A pictorial representation of the proposed final revenue increase is set forth on Part B, Page 10 of Statement O.

Q. Would you please explain Exhibit No. ____(TAA-2)?

A. Yes. Exhibit No. ____ (TAA-2) depicts bill comparisons based on typical monthly consumption levels for an annual period for Residential and Firm General Service customers. As shown by the comparisons, the proposed rate structure will result in an average increase, based on final proposed rates, of approximately $3.37 per month for the typical Residential customer using 86 dk on an annual basis. A Small Firm

General Service customer (Rate 70 with a meter rated less than 500 cubic feet per hour) would see an increase of approximately $3.23 per month or 3.9% and a Large General Service customer (Rate 70 with a meter rated 500 cubic feet per hour or more) would see an increase of approximately $13.05 per month or 2.3%.

<u>**Embedded Class Cost of Service Study**</u>

Q. Would you please explain the embedded class cost of service study contained in Statement L?

A. Yes. Statement L, pages 1 through 3 provide a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the pro forma rate of return of 8.489% were to be earned for the demand, energy and customer cost components of each rate schedule.

A summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation is provided in Statement L, Schedule L-1, pages 4-5. Statement L, Schedule L-2, pages 1 through 30 is a report of the rate base, income statement and pro forma adjustments as allocated to each rate schedule. The allocation factor applied to the total Montana gas amount is shown on each line item and allocation factors used to allocate the total Montana gas amount to each class and cost component as referenced are provided in Statement L, Schedule L-3.

The embedded class cost of service study is based on the results for Montana gas operations recorded for the 12 months ended December

31, 2011 as adjusted to reflect pro forma adjustments as sponsored by Ms. Mulkern.

Q. What were the results of the embedded cost of service study?

A. The overall Montana gas rate of return based on the actual results for the 12 months ending December 31, 2011 adjusted for known and measurable changes is 3.718%. The returns by customer class are as shown below:

Residential Service	0.278%
Small Firm General Service	11.364%
Large Firm General Service	7.444%
Small Interruptible Sales & Transportation	40.315%
Large Interruptible Sales & Transportation	13.934%

Q. How did you determine what costs should be assigned to each class of customers?

A. The starting point was classifying the functionalized costs by FERC account for all rate base and income statement items as demand, energy or customer related based on the component of service being provided. Demand-related costs are costs that vary with the demand imposed by the customer, energy-related costs are costs that vary with the natural gas commodity the customer uses, and customer-related costs are fixed costs driven by the number of customers served.

Next the plant, expense and revenue items that were identified as directly related to a specific class of customers were directly assigned to the appropriate class. Finally, the remaining costs were allocated using the various allocation factors shown in Statement L, Schedule L-3, on the basis of cost responsibility.

Q. Would you please provide an overview of the allocation process including the rationale underlying the choice of allocation factors?

A. Yes. I will start with the plant in service items on the rate base schedule starting on Schedule L-2, Page 1. The plant allocation serves as the basis for allocating many of the other rate base items. The investment in production plant represents the Company's investment in the Billings Landfill facility and was allocated based on pro forma dk sales (Factor 3) on the basis the gas produced is utilized by the sales customers.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Distribution mains, services and meters represent approximately 94% of the total distribution investment and therefore the allocation of these three accounts drives the allocation of the remaining distribution investment. The investment in distribution mains has been assigned as a demand component and allocated to each rate class based on the system peak demand attributed to each class. Montana-Dakota has historically attributed a portion of investment in distribution mains to both the customer component and the demand component. In this case, Montana-Dakota is proposing to assign the mains to only the demand component in recognition of the fact the allocation of mains to the customer component has not been well accepted in past cases. The investment in services, service regulators and meters is related solely to a customer connection and therefore classified as customer related. Services, service regulators and meters were allocated to the rate classes based on Factor 10 representing meters weighted by customer class derived by comparing the installed cost per meter for each rate class to the cost necessary to serve Residential customers. The weights were then applied to the number of customers in each rate class. The remainder of the rate base items is self explanatory with the allocation factor noted for each line item.

Q. Would you please continue with an explanation of the income statement items in the class cost of service study?

A. Yes. The allocation of the income statement items starts on Schedule L-2, Page 3 with the allocation of revenues. As shown, sales and transportation service revenues are directly assigned based on the revenues produced by each rate class. The other revenues are allocated based on the source of the revenue item. Each item is shown along with the allocation factor applied. Operation and maintenance expenses consisting of the cost of purchased gas, production, distribution customer accounts, customer service and information, sales and administrative and general expenses are shown starting at Schedule L-2, Page 3. The cost of purchased gas is directly assigned to each class based on the gas costs included in pro forma revenues. The cost of purchased gas is recovered through the gas cost tracking adjustment and is not recovered through the rates that will be established in this rate case. Production expenses are classified as energy related and allocated based on Dk sales (Factor 3) to each class. The remaining operation and maintenance expenses are allocated based on cost causation and typically follow the plant investment previously described in the rate base section. The remainder of the income statement reflects the allocation of depreciation expense, taxes other than income and income taxes as denoted by each line item. Finally, the pro forma adjustments set forth in the Overall Cost of Service section, Rule 38.5.176, Schedule L-1, pages 3 through 5 are allocated beginning at Schedule L-2, Page 7. Again the allocations primarily follow the corresponding plant or expense item previously allocated. The allocation of costs to each rate schedule is presented in the same format as described above for Residential Rate 60, in Schedule L-2.

Q. For what purpose has the embedded class cost of service study been used?

A. The study results have been used for the purpose of analyzing the various components comprising the total rate applicable to each customer class. The embedded cost study was also utilized in the development of certain items in the marginal cost study as I will explain next in my testimony.

<u>Marginal Cost of Service Study</u>

Q. Would you please explain the Marginal Cost Study provided in Exhibit No.____(TAA-3)?

A. Yes. Page 1 of Exhibit No.___ (TAA-3) presents the results of the long-run marginal cost of service study as reconciled to the total proposed revenue requirement as identified in the direct testimony of Ms. Mulkern in Exhibit No. __(RAM-1). The marginal cost of service study is provided in compliance with ARM Rules 38.5.176-177. The marginal cost study represents costs for calendar year 2011 and escalated to 2014 in accordance with ARM Rule 38.5.176. The summary of the marginal unit costs by customer class is set forth on Page 2 of Exhibit No. ___(TAA-3) with the underlying support for each of the cost components, 1) Commodity Cost 2) Demand Cost and 3) Customer Cost set forth on Pages 3 through 28 of Exhibit No. ___(TAA-3).

Q. Is the costing methodology used in this marginal cost study consistent with the methodologies used in previous marginal cost studies filed by the Company?

A. Yes, with the exception of the addition of a production related marginal cost to reflect the Company's addition of gas production facilities with the addition of the Billings landfill facility in 2010.

Q. Would you please explain how the marginal cost components were derived?

A. Yes. I will discuss in turn each of the three components 1) marginal cost of gas, 2) marginal distribution demand costs and 3) marginal customer costs as summarized on Exhibit No. ____(TAA-3) Page 1. The marginal cost of gas shown on Exhibit No. ____(TAA-3)

Page 3 reflects the pro forma cost of gas level for calendar year 2011 as set forth in Rule 38.5.157 Statement G, Page 3 and as described by Ms. Mulkern in her direct testimony. Use of this cost of gas amount is representative of the long-run marginal cost of gas including pipeline related charges based on information known at the time this case was filed. The commodity cost by rate schedule is consistent with the application of the Company's gas cost tracking adjustment. The production related marginal costs associated with the Billings Landfill as calculated on Exhibit No.___(TAA-3) pages 4 and 5 was added to the marginal commodity cost of gas. The marginal distribution demand cost component as shown on Exhibit No.___(TAA-3) Page 6 for the each rate schedule was developed based on the incremental investment in distribution mains and related facilities required to provide an additional Mcf of capacity on a peak day. The starting point for this calculation was the historic investment in nine distribution system projects completed in 2011 that resulted in an increase in the overall capacity available on the system divided by the Mcfd capacity additions associated with the incremental investment for each project as shown on Page 7 of Exhibit No.___(TAA-3). The total marginal distribution demand investment reflects this incremental capacity cost, the cost per peak day associated with the main installed to serve a typical customer provided on Page 13 of Exhibit No.___(TAA-3) plus an allocation of general and common plant as shown on Page 14 of Exhibit No.___(TAA-3). An Annual Levelized Real

Carrying Charge was then applied to the total marginal distribution demand investment cost. Finally, demand related Operation & Maintenance Expenses, Administrative and General Expenses, Taxes Other Than Income Taxes and a Working Capital component were added resulting in the total Demand-Related Marginal Cost of Distribution for each rate class. The workpapers underlying the demand component of each of the costs noted above are included as Pages 13 through 28 of Exhibit No.___(TAA-3).

The marginal customer cost components by rate schedule as shown on Exhibit No.___(TAA-3), Page 2 were developed based on the minimum incremental distribution investment necessary to connect a new customer. The Marginal Customer Costs for a service line, meter and house regulator are presented on Exhibit No.___(TAA-3), Page 13. These direct customer related investments were carried forward to pages 8 through 12 of Exhibit No.___(TAA-3) where the annualized customer cost was derived. This was accomplished in a fashion similar to the calculation of the annualized distribution demand related costs. The total marginal customer investment reflects the incremental customer related plant investment plus an allocation of general and common plant as shown on pages 8 through 12 of Exhibit No.___(TAA-3). An Annual Levelized Real Carrying Charge was then applied to the total marginal customer related investment cost. Customer related Operation & Maintenance Expenses, Administrative and General Expenses, Taxes Other Than Income Taxes and a Working Capital component were then added resulting in the total Customer-Related Marginal Cost of Distribution for each rate class. The workpapers underlying the customer component of each of the costs noted above are included as pages 13 through 28 of Exhibit No.___(TAA-3).

Q. How were the expenses referenced above that have been included as components of the demand and customer related costs developed?

A. The costs were based on a 5 year average of embedded costs for the period 2007 through 2011 and restated to reflect costs as of January 1, 2014 in accordance with Rule 38.5.176 (6) (a) that requires marginal costs to reflect costs two years beyond January 1st of the year in which the filing is submitted.

Q. What are the results of the marginal cost of service study?

A. The results of the study are presented on Page 1 of Exhibit No.___(TAA-3) and pictorially represented in Statement O. The pro forma billing determinants were applied to each of the cost components described above resulting in a total marginal cost of service for Montana gas operations of $68,097,062. An adjustment factor was developed to bring the total marginal cost of service equal to the Company's proposed revenue requirement of $62,794,604 and applied to the marginal costs by rate class. The adjusted marginal costs by rate class were then compared to the revenues before the increase resulting in a percentage increase required from each rate class. Following is a comparison of the percentage increase by class based on the embedded class study (Rule 38.5.176, Statement L, Schedule L-1 Pages 1 and 2) and the Long-Run Marginal Cost Study (Exhibit TAA-3, Page 1).

Class	Increase in Revenues Embedded	Increase in Revenues Marginal
Residential	10.96%	20.03%
Small Firm General Service	-2.98%	4.96%
Large Firm General Service	1.11%	-19.40%
Small Interruptible	-25.61%	-48.85%
Large Interruptible	-12.64%	-94.88%
Total	5.86%	5.86%

As shown, while the magnitude is unique to each study, both studies indicate that more than the entire increase should be allocated to the residential class while the other classes' revenue requirements, other than the Small Firm General Service class, should be decreased.

Q. For what purpose have the class cost of service studies been used?

A. The results of the studies have been primarily used as a guide in pricing the various components comprising the total rate applicable to each customer class.

<u>Distribution of the Revenue Requirement</u>

Q. What methodology did you use to apportion the proposed rate increase among the customer classes?

A. In designing the proposed rates to reflect the additional revenue requirements, I primarily used the embedded cost study as a guide. The revenue increase necessary to bring each of the rate classes to the overall rate of return ranges from an increase of approximately 11 percent for Residential Rate 10 to a reduction of 26 percent for Small Interruptible Service Rate 71. In allocating the revenue increase to each class I used an iterative process to mitigate the impact associated with the increase required to reach the overall return by rate class. By setting the Small and Large Interruptible classes at a 1.4% increase, and the Firm General Service Class at twice that (2.8%), an increase of 7.9% was required from the Residential class. This represents less than the required amount to bring the Residential class to the overall requested return but represents approximately 72% of the Residential required increase based on the embedded cost study and approximately 40% of the Residential required increase based on the marginal cost study, representing a significant movement to cost based rates.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim required revenue increase of $1,686,101, identified by Ms. Mulkern, is proposed to be billed as a separate line item on the bill based on 8.99% of the amounts billed under the Basic Service Charge and Distribution Delivery rate components on each bill under Rates 60, 70 and 72. This methodology was used in the application of the interim increase authorized in the Company's last electric rate case in Docket No. D2010.8.82. Montana-Dakota has not proposed an allocation of the interim request to the interruptible service classes because of the returns currently provided by both of the interruptible classes are well above the overall required return and because most of the large interruptible customers are taking service under a contract rate flexed below the maximum rate today. The calculations supporting the application of the interim increase to each class are provided in Statement M attached to the Application for Interim Increase in Natural Gas Rates. The proposed tariff sheets reflecting the proposed interim increase are provided in Appendix A of the Application for Interim Increase in Natural Gas Rates. As shown, the tariffs prescribe the interim increase as 8.99% of the amount billed under the Basic Service Charge and Distribution Delivery Charge. The interim percentage increase will not be applied to any amounts billed under the Gas Cost Tracking Procedure Rate 88. The interim increase represents an average increase of 2.9% over total pro forma revenues including the cost of gas revenues.

Q. What is the percentage of the proposed interim and final increase by class of customer?

A. The proposed interim and final increase to each of the classes is shown in the table below:

Class	***Interim***	***Final***
Residential	**3.1%**	**7.9%**
Firm General	**2.8%**	**2.8%**
Small Interruptible	**0.0%**	**1.4%**

Large Interruptible	**0.0%**	**1.4%**
Overall	**2.9%**	**5.9%**

Q. What were the objectives underlying the allocation of the increase and the rates proposed to recover the revenue requirement?

A. The embedded cost of service study and proposed revenue allocation embody several of the recognized objectives by their effectiveness in yielding the total revenue requirement under the fair-return standard, fairness of the specific rates in the apportionment of the total costs of service among the different consumers, and efficiency of the rate classes. The rate forms proposed also recognize a balanced and gradual move toward meeting the objectives noted above in order to be cognizant of the objective of rate stability. In order to capture that balance, the proposed rates reflect a move toward cost based rates but not the full step necessary to price each service to reflect the specific marginal or embedded cost components.

Q. How are you proposing to collect the allocated final increase from each of the rate classes?

A. First, I am proposing increases to the Basic Service Charges for each of the rate schedules. The Basic Service Charge under Residential Rate 60 is proposed at $0.35 per day which reflects an average monthly charge of $10.64, an increase of $4.29 per month from the currently effective charge. The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour is proposed at $0.40 per day and $0.80 per day for customers requiring the larger meters capable of measuring gas flows of 500 cubic feet per hour or greater. The resulting average monthly charges will be $12.16 and $24.32 respectively representing an increase of $1.76 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $2.27 per month in the Basic Service Charge for customers requiring meters rated at 500 cubic feet per hour or higher. The Basic Service Charges applicable to Small Interruptible Sales Rate 71 and Small Interruptible Transportation Service Rate 81 is proposed to increase by $50.00 per month resulting in a Basic Service Charge of $175.00 for the sales service and $225.00 for the transportation service. Large Interruptible Sales Rate 85 and Large Interruptible Transportation Service Rate 82 Basic Charges is proposed to increase to $605.00 per month and $655.00 per month respectively representing an increase of $125.00 per month.

After taking into account the revenue increase associated with the changes in the Basic Service Charge, the remaining increase in revenues is proposed to be collected through the applicable Distribution Delivery Charge components. The proposed increase in the Residential Basic Service Charge results in a decrease to the Distribution Delivery Charge.

The rate design calculations supporting the final rate levels are included in Statement M, Pages 1-7. A representation of the annual billing impact for the Residential and Firm General Service classes is provided on Pages 8-10 of Statement M.

Q. Would you please explain the rationale for the significant increase in the Residential Basic Service Charge?

A. The proposed increase in the Basic Service Charge, to move this component closer to cost, is necessary for several reasons. Moving fixed cost recovery to the Basic Service Charge and away from the usage charge will first minimizes subsidies within the class and secondly minimize the under-recovery of fixed costs when customers take measures to conserve energy and more efficiently utilize natural gas. Today the Company and its shareholders are harmed when conservation results in lower use. This inequity may be addressed through tracking mechanisms or more simply by adjusting the rate components to more closely match costs. Residential customers in Montana have reduced their average annual usage on a weather normalized basis from 94 dk at the time of the last rate case in 2004 to 86 dk on an annual basis today as a result of conservation efforts including improved appliance efficiency and improved housing construction. An Energy Information Administration, Office of Oil and Gas report in June 2010 entitled "Trends in U.S. Residential Natural Gas Consumption" supports that this trend is expected to continue into the future in a couple of key findings 1) A long-term trend in declining U.S. household consumption is apparent, with year over year declines in residential per-customer consumption in 16 out of the past 19 years 2) according to EIA data, newer vintage homes or houses constructed between 1990 and 2005, consumed 25 percent less natural gas for space heating, than homes built prior to 1990 and 3) one-third of all furnaces currently sold measure an AFUE of 90 percent or higher. This trend causes a need to address the current rate structure where a significant portion of fixed costs are recovered through the usage charge. A recent survey by the American Gas Association (AGA) as of March 2012 indicates Commissions and utilities across the nation are addressing this issue through Non-Volumetric Rate Designs, Decoupling, Flat Monthly Fees or Rate Stabilization mechanisms. As shown on Exhibit No. ___(TAA-4), 33 such mechanisms have been approved with two pending as of March 2012.

Distribution Delivery Stabilization Mechanism

Q. Would you please describe the Distribution Delivery Stabilization Mechanism (DDSM) Montana-Dakota is proposing?

A. Montana-Dakota is proposing a mechanism to adjust customer bills to reflect the Distribution Delivery Charge component that would be billed based on normal weather during the winter months defined as November 1 through May 1. Montana-Dakota has requested such an adjustment in the last two general rate cases. However, the last two rate cases have been determined based on settlements and a weather adjustment mechanism has not been part of the settlement packages. Montana-Dakota is again proposing to implement a mechanism to adjust its gas distribution delivery revenues to reflect normal weather in a manner similar to that employed in two other jurisdictions served by Montana-Dakota (DDSM was implemented in North Dakota in 2004 and in South Dakota in 2005). An adjustment mechanism is required in order to minimize the impact of weather on Montana-Dakota's financial condition and on the volatility of customers' gas bills.

Q. Please explain how weather influences the ratemaking process for Montana-Dakota.

A. As part of the ratemaking process Montana-Dakota's revenues are based on weather-normalized consumption. The process of normalizing revenue for weather consists of either increasing or decreasing actual gas volumes, in relative terms, by the difference between normal temperatures established for Montana-Dakota's service area and actual temperatures experienced during the test year, in this case calendar year 2011.

Q. What standard measure is used to describe relative temperatures for purposes of setting gas rates?

A. A "heating degree-day" is a standard energy industry measure of the relative coldness of the temperatures experienced, based on the extent to which the daily mean temperature falls below 60 degrees Fahrenheit ("F"). For example, on a day when the mean temperature is 35 degrees F, there would be 25 heating degree-days.

Q. How were weather-normalized gas volumes used to derive the usage charges proposed in this case?

A. Montana-Dakota's Distribution Delivery Charge, representing cost recovery for distribution costs that are primarily fixed in nature, was derived by dividing the appropriate costs, or the portion of the revenue requirement, to be recovered through usage rates by the weather-normalized gas volumes. These rates and charges are designed to provide the Company with an opportunity to recover the significant level of fixed costs it incurs to provide service, at the levels determined in the last rate case. Fixed costs are costs incurred that do not vary with the amount of gas delivered to customers. For Montana-Dakota, these costs are composed of operation and maintenance costs, administrative and general expenses, depreciation, taxes, and return on investment. As defined, these costs do not vary in the short-term with changes in temperature. If actual temperatures are normal, the Company has a reasonable opportunity to fully recover its fixed costs of service at established levels. However, normal temperatures seldom occur. Therefore, as a result of abnormal weather, the earnings (i.e., margin revenues) can vary widely from the levels authorized by this Commission. A graphical representation of the monthly heating season weather since the last rate case is provided in Exhibit No.___(TAA-5). As shown, the weather has been both colder than normal in the period since the last rate case in 2004 with the most recent heating season (November 2011 through May 2012) the warmest since the last general rate case and the immediately preceding heating season exhibiting the coldest heating season since the last general rate case.

Q. Please explain how fluctuations in weather over time impact Montana-Dakota's temperature-sensitive customers?

A. Since the gas customer bills are based on the level of gas usage, temperature-sensitive customers' monthly bills can vary widely due to changing weather conditions. These types of fluctuations can be particularly burdensome for people who are on a fixed income.

Without the application of DDSM, if actual temperatures were colder than normal, the typical gas customer would use more gas, pay more for service, and arguably overpay their share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since Montana-Dakota's level of fixed costs does not change, the higher gas volumes applied against the same unit rate will generate higher non-gas revenues than the level of fixed costs established for ratemaking purposes. This occurs during weather periods when the customer's bill is already adversely impacted by the increased commodity portion of the bill resulting from higher usage levels.

In warmer than normal weather, the reverse situation will occur. Customers' gas usage would decrease with warmer temperatures, thus generating lower non-gas revenues than required to recover Montana-Dakota's total fixed costs that do not decrease due to warm weather.

Q. You noted earlier that Montana-Dakota and its customers are exposed to the impacts of weather. Can you describe why?

A. Because customer gas usage varies due to colder or warmer-than-normal weather. During a relatively cold winter, customers have higher gas bills, and in a relatively warmer winter, they have lower gas bills. Conversely, in a cold winter, Montana-Dakota's earnings are relatively higher - while in a warm winter, its earnings are lower. In the end, both customer bills and utility earnings will fluctuate based on weather, a factor not within the customer's or the Company's control and not reflective of the costs of service.

Q. Does Montana-Dakota's proposed DDSM represent an effective solution to the impacts of weather on customers and the Company?

A. Yes. Montana-Dakota's proposed DDSM is fair, symmetrical, and beneficial to customers and the Company for the following reasons:

1. When it is colder-than-normal, customers do not overpay for Montana-Dakota's fixed costs, and the Company does not over-recover margin. Conversely, when it is warmer-than-normal, customers do not underpay for Montana-Dakota's fixed costs, and the Company does not under recover margin.
2. Montana-Dakota's proposed DDSM effectuates in rates the Commission's assumption of normal weather - the mechanism simply allows for the weather-normalized recovery of margin as

intended through the weather-normalization of rates established in a general rate case.

3. Montana-Dakota's proposed DDSM coupled with the proposed increase in the fixed Basic Service Charge provides an effective means to address the issue of margin volatility while continuing to provide the proper price signal to customers to conserve energy use.

Q. Please explain the structure and key design elements of Montana-Dakota's DDSM proposal.

A. Montana-Dakota's DDSM will adjust distribution delivery charges on a current month basis to reflect changes in margin due to variances in firm gas sales volumes from normal weather conditions. The DDSM calculations will be made on a real-time basis by individual customer, which means that each customer will be charged for gas service based on the customer's specific gas usage characteristics, at the time the customer made the decision to use natural gas at that level. Montana-Dakota's proposed DDSM will be applicable to its residential and firm general service customers – Residential Service - Rate Schedule 60 and Firm General Service - Rate Schedule 70. The DDSM will be computed and applied to customers' bills during the months of November 1 through May 1.

Q. Please explain how Montana-Dakota's proposed DDSM will operate.

A. The proposed DDSM tariff (Rate Schedule 87) specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the heating season, defined as November 1 through May 1. Because the gas volumes used to calculate the distribution delivery charge are based on volumes expected under normal weather conditions, the Company will either over collect distribution revenues if weather is colder than normal or under collect distribution revenues if weather is warmer than normal in the absence of the DDSM. As described in the proposed tariff, the DDSM adjustment is calculated based on a ratio of the normal heating degree days as compared to the actual heating degree days which will be multiplied by the temperature sensitive consumption for each customer. The non-temperature sensitive use per day per customer, determined in the normalization process in this case, will be determined for each customer based on the days in the service period. The non-temperature sensitive use per day will remain the same until Montana-Dakota files another general rate case and the change in non-temperature sensitive use is significant. The DDSM rate will be stated as a surcharge or credit on all rate schedules to which the DDSM is applicable. If weather is colder than normal, the DDSM will be a credit adjustment and reduce customers' bills. If weather is warmer than normal, the DDSM will be a positive adjustment and increase customers' bills.

Q. Please summarize the expected billing effect of the DDSM.

A. When temperatures are warmer than normal the DDSM results in customers' bills that are higher than without the mechanism, but still lower than the expected bill under normal temperature conditions. This is because the customer still uses less gas and gas costs are approximately 66% of the typical bill. Thus, customers still realize savings associated with warmer temperatures and because the adjustment assumes normal weather, customers do not experience as large a bill increase as when weather is colder than normal.

Q. Even with a positive rate adjustment from DDSM applied to customers' bills, please explain why the customers still realize savings during warmer-than-normal weather.

A. Customers generally realize significantly reduced bills during warm weather for two reasons. First, a temperature-sensitive customer will have significantly reduced gas usage during warmer-than-normal periods. Therefore, although the amount of fixed costs to be recovered by Montana-Dakota using the DDSM does not change, the customer will purchase and pay for less gas. Second, during warmer than normal weather conditions, commodity gas costs are typically less expensive, and these gas costs savings are flowed through to customers.

Q. Would you illustrate the application of the DDSM with an example?

A. Yes. Exhibit No.___(TAA-6) presents an example of a typical Montana-Dakota residential gas customer's bill in February, including DDSM, under three conditions 1) normal weather 2) 20 percent warmer than normal weather and 3) 20 percent colder than normal weather. As shown, in the scenario where weather was 20 percent warmer than normal, the customer would realize a significant gas supply savings in its monthly bill by paying for only 11.4 Dk of gas instead of the 13.9 Dk that would have been used had temperatures been normal. Based on this difference in use per customer, the proposed DDSM would add $2.50 to the total bill, with the total bill, after the DDSM adjustment, still $9.63 less than a normal February bill. In a colder-than-normal winter, the opposite is true – customer bills go up to reflect greater usage and the proposed DDSM would provide a reduction to the bill. As shown, the customer will continue to see a price signal to lower the amount of natural gas used in this weather condition but would receive a credit of $2.50 under the DDSM to adjust the Distribution Delivery Charge component of the bill to reflect normal weather.

Q. What are the benefits to Montana-Dakota and to its customers of implementing its DDSM proposal?

A. There are several significant benefits from implementing Montana-Dakota's DDSM proposal, including:

1. The proposed mechanism will mitigate the impact of significantly colder-than-normal weather on customers' bills as the mechanism will create a downward adjustment in the customer's bill while in warmer-than-normal weather, when a customer's gas usage and resulting bill are relatively low, there will be a upward adjustment in the customer's bill;

2. The proposed mechanism reduces fluctuations in Montana-Dakota's earnings, both up and down, as the result of weather fluctuations; and
3. With the implementation of the proposed DDSM, customers will pay each year approximately the same amount for gas delivery service as if they had experienced normal weather.

Q. Would you please briefly describe other changes made to the Company's gas tariff?

A. Yes, following is a description of other changes the Company is proposing to make to its gas tariff:

- The Basic Service Charges applicable to the Residential and Firm General Service classes have been stated on a daily basis. Charging this fixed cost on a daily basis better matches the way customers are billed i.e., the days between billing periods vary due to meter reading cycles and customer cut-ins and cut-outs occurring outside their normal billing cycle. Bills for service outside a normal period are currently normalized but the customer cannot readily determine how the bill was determined. A daily Basic Service Charge will allow the customer to simply multiply the number of days in service during the current billing period (now shown on the bill) by the applicable Basic Service Charge.
- The Electric Generation Interruptible Transportation Service

Rate 80 is proposed to be deleted as the mechanism is no longer used and no longer applicable in the Midwest Independent Transmission System Operator, Inc.'s energy market.

- Minor changes which are self explanatory have been made to the majority of the rate schedules. These changes are clearly denoted on the tariff sheets reflecting the legislative format.

Q. Does this conclude your direct testimony?
A. Yes, it does.

Docket No. ______
Exhibit No. ______(TAA-1)
Page 1 of 2

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER INTERIM RATES
GAS UTILITY - MONTANA
Pro Forma 2012

Customer Class/Rate	Pro Forma 1/ Customers	Pro Forma 1/ Dk	Pro Forma 1/ Revenue	Total Proposed Interim Revenue 1/	Proposed Interim Revenue Increase	Percent Increase
Residential - Rate 60	70,161	6,097,461	$35,729,916	$34,632,056	$1,097,860	3.1%
Firm General Service - Rates 70 & 72	8,700	3,813,826	21,256,783	20,668,221	588,562	2.8%
Small Interruptible						
Sales - Rate 71	9	218,586	804,782	804,782		
Transport - Rates 81	35	686,293	582,729	582,729		
Total Small Interruptible	44	904,879	1,387,511	1,387,511	0	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0	0		
Transport - Rate 82	5	4,197,933	548,804	548,804		
Total Large Interruptible	5	4,197,933	548,804	548,804	0	0.0%
Total Montana	78,910	15,014,099	$58,923,014	$57,236,592	$1,686,422	2.9%

1/ Rule 38.5.177, Statement M, Page 1.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - MONTANA
Pro Forma 2012

Customer Class/Rate	Pro Forma Customers 1/	Pro Forma Dk 1/	Pro Forma Revenue 1/	Total Proposed Revenue 2/	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	70,161	6,097,461	$35,729,916	$38,566,241	$2,836,325	7.9%
Firm General Service - Rates 70 & 72	8,700	3,813,826	21,256,783	21,851,209	594,426	2.8%
Small Interruptible						
Sales - Rate 71	9	218,586	804,782			
Transport - Rates 81	35	686,293	582,729			
Total Small Interruptible	44	904,879	1,387,511	1,406,672	19,161	1.4%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	5	4,197,933	548,804			
Total Large Interruptible	5	4,197,933	548,804	556,304	7,500	1.4%
Total Montana	78,910	15,014,099	$58,923,014	$62,380,426	$3,457,412	5.9%

1/ Rule 38.5.164, Statement H, Page 3.
2/ Rule 38.5.177, Statement M, Page 2.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$81.10	$83.47	$2.37	2.92%
February	14	76.11	78.61	2.50	3.28%
March	11	61.16	64.05	2.89	4.73%
April	8	46.21	49.48	3.27	7.08%
May	5	31.27	34.92	3.65	11.67%
June	3	21.30	25.21	3.91	18.36%
July	2	16.32	20.35	4.03	24.69%
August	2	16.32	20.35	4.03	24.69%
September	2	16.32	20.35	4.03	24.69%
October	4	26.28	30.06	3.78	14.38%
November	8	46.21	49.48	3.27	7.08%
December	12	66.15	68.90	2.75	4.16%
Total	86	$504.75	$545.23	$40.48	8.02%

Average Increase per Month $3.37

RATE 60	Current 1/	Proposed 2/
Basic Delivery Charge	$6.35	$10.64
Distribution Delivery	$1.126	$0.998
Cost of Gas	3.857	$3.857

1/ Distribution rates effective November 1, 2009 Docket No. D2009.9.123 and Docket No. D2009.9.124 and weighted cost of gas for 2011.

2/ Cost of gas equals weighted cost of gas for 2011.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (< 500 Cubic Feet Per Hour Meters)

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	33	$182.33	$187.52	$5.19	2.85%
February	29	161.49	166.27	4.78	2.96%
March	23	130.23	134.38	4.15	3.19%
April	17	98.97	102.50	3.53	3.57%
May	9	57.29	59.99	2.70	4.71%
June	4	31.24	33.42	2.18	6.98%
July	2	20.82	22.79	1.97	9.46%
August	1	15.61	17.47	1.86	11.92%
September	2	20.82	22.79	1.97	9.46%
October	7	46.87	49.36	2.49	5.31%
November	16	93.76	97.18	3.42	3.65%
December	26	145.86	150.32	4.46	3.06%
Total	169	$1,005.29	$1,043.99	$38.70	3.85%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$10.40	$12.16
Distribution Delivery	$1.353	$1.457
Cost of Gas	3.857	$3.857

1/ Distribution rates effective November 1, 2009 Docket No. D2009.9.123 and Docket No. D2009.9.124 and weighted cost of gas for 2011.

2/ Cost of gas equals weighted cost of gas for 2011.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (> 500 Cubic Feet Per Hour Meters)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE	
January	216	$1,147.41	$1,172.14	$24.73	2.16%	17.0%
February	194	1,032.79	1,055.24	22.45	2.17%	13.0%
March	158	845.23	863.93	18.70	2.21%	13.0%
April	121	652.46	667.31	14.85	2.28%	8.0%
May	75	412.80	422.87	10.07	2.44%	5.0%
June	41	235.66	242.19	6.53	2.77%	3.0%
July	30	178.35	183.74	5.39	3.02%	2.0%
August	27	162.72	167.80	5.08	3.12%	2.0%
September	33	193.98	199.68	5.70	2.94%	4.0%
October	61	339.86	348.47	8.61	2.53%	7.0%
November	112	605.57	619.49	13.92	2.30%	11.0%
December	176	939.01	959.58	20.57	2.19%	15.0%
Total	1,244	$6,745.84	$6,902.44	$156.60	2.32%	100.0%

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$22.05	$24.32
Distribution Delivery	$1.353	$1.457
Cost of Gas	3.857	$3.857

1/ Distribution rates effective November 1, 2009 Docket No. D2009.9.123 and Docket No. D2009.9.124 and weighted cost of gas for 2011.

2/ Cost of gas equals weighted cost of gas for 2011.

MONTANA-DAKOTA ULITIES CO.
MARGINAL COST OF SERVICE STUDY
INDEX OF EXHIBIT NO. ___(TAA-3)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

Marginal Cost	Total	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(3)	(4)	(5)	(6)
I - Marginal Cost-Based Revenues						
Marginal Costs						
Commodity Cost ($/Dk) 1/		$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/						
Distribution Level Service 2/		$209.06	$141.00	$25.00	$7.05	$3.00
Customer Cost ($/Month) 2/		$15.26	$22.97	$69.50	$230.08	$418.60
Billing Determinants 3/						
Dk Sales	10,129,873	6,097,461	1,119,203	2,694,623	218,586	0
Dk Transportation	4,884,226	0	0	0	686,293	4,197,933
Total Dk Throughput	15,014,099	6,097,461	1,119,203	2,694,623	904,879	4,197,933
Dk Throughput at Distribution	12,268,927	6,012,077	1,097,011	2,633,666	732,540	1,793,633
Peak Demand at Dist. (Mcfd)	85,504	48,225	10,068	20,290	2,007	4,914
Average No. of Customers	78,910	70,161	6,547	2,153	44	5
Average No. of Bills	946,920	841,932	78,564	25,836	528	60
Marginal Cost-Based Revenues						
Commodity (Sales Gas)	39,464,717	23,883,755	4,383,918	10,554,838	642,206	0
Demand (Distribution Level)	12,037,648	10,081,919	1,419,588	507,250	14,149	14,742
Customer	16,594,697	12,847,882	1,804,615	1,795,602	121,482	25,116
Total	$68,097,062	$46,813,556	$7,608,121	$12,857,690	$777,837	$39,858
II - Final Proposed Revenue Requirement 4/	$62,794,604					
III - Adjustment Factor	0.92213382					
IV - Revenue Requirements						
Proportioned to classes	$62,794,604	$43,168,363	$7,015,706	$11,856,511	$717,270	$36,754
Less Miscellaneous Revenue 5/	$416,112	$280,482	$37,585	$81,820	$7,553	$8,672
Net Revenue Requirement	$62,378,492	$42,887,881	$6,978,121	$11,774,691	$709,717	$28,082
V - Operating Revenue Before Increase 5/	$58,923,014	$35,729,916	$6,648,114	$14,608,669	$1,387,511	$548,804
VI - Required Increase	$3,455,478	$7,157,965	$330,007	($2,833,978)	($677,794)	($520,722)
VII- Percentage Increase	5.86%	20.03%	4.96%	-19.40%	-48.85%	-94.88%

1/ Exhibit No. __(TAA-3) page 2
2/ Exhibit No. __(TAA-3) pages 6-12.
3/ Rule 38.5.164, Statement H, page 3.
4/ Rule 38.5.175, page 7.
5/ Rule 38.5.176, Schedule L-1, page 4

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

SUMMARY OF MARGINAL COSTS BY CUSTOMER CLASS

	Customer Class				
Marginal Cost	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(4)	(5)	(6)
Commodity Cost ($/Dk) 1/	$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/ Distribution Level Service	$209.06	$141.00	$25.00	$7.05	$3.00
Customer Cost ($/Customer/Month) 3/	$15.26	$22.97	$69.50	$230.08	$418.60

1/ Exhibit No. __ (TAA-3), page 3.
2/ Exhibit No. __ (TAA-3), page 6.
3/ Exhibit No. __ (TAA-3), pages 8-12.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

MARGINAL COST OF GAS

	Firm Sales	Interruptible Sales	Interruptible Transportation
	(1)	(2)	(3)
Marginal Commodity Cost 1/	$3.857	$2.878	--
Production Marginal Cost	0.060	0.060	--
Total Marginal Cost of Gas	$3.917	$2.938	$0.000

1/ Rule 38.5.157, Statement G, page 3. Annual 2011 gas cost level adjusted for losses.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF PRODUCTION-RELATED MARGINAL COSTS

Line No.	Description	Amount
1	Average Production Investment 1/	$0.31
2	General and Common Plant Allocation (Line 1 x 27.26%) 2/	0.08
3	Marginal Cost Including General Plant	0.39
4	Annual Levelized Real Carrying Charge (Percent of Investment)	8.655%
5	Annual Levelized Amount (Line 3 x Line 4)	0.03
6	Production-Related Operation & Maintenance Expense (Line 3 x 6.49%) 1/	0.03
7	Demand-Related Administrative & General Allocation (Line 3 x 0.41%) 3/	0
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	0.06
	Taxes Other Than Income Taxes (Excl. Revenue-Related)	
9	Property Taxes (Line 3 x 0.60%) 4/	0
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 4/	0
11	Sub-Total Taxes Other	0
	Working Capital Requirement	
12	Materials and Supplies (Line 3 x .14%) 2/	0
13	Prepayments (Line 3 x 0.01%) 2/	0
14	Total Working Capital	0
15	Required Return on Working Capital 5/	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0
17	Sub-Total (Line 8 + Line 11 + Line 16)	0.06
18	Revenue-Related Taxes (Line 17 x 0.38%) 5/	0
19	Total Marginal Cost of Production	$0.06

1/ Exhibit No. __(TAA-3), page 5.
2/ Exhibit No. __(TAA-3), page 14.
3/ Exhibit No. __(TAA-3), page 24.
4/ Exhibit No. __(TAA-3), page 26.
5/ Exhibit No. __(TAA-3), page 15.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

PRODUCTION-RELATED MARGINAL COSTS

	2010	2011	Average
Production Investment	$2,972,781	$3,096,756	$3,034,769
	1.05	1.01	
Investment Adj to 1/1/2014	$3,121,420	$3,127,724	$3,124,572
Investment per Dk Sold			$0.308

Production O&M Expense	$188,558
	1.0750
O&M Adj to 1/1/2014	$202,700
O&M as % of Avg Adj Plant	6.49%

Handy Whitman S.N.G Equip

	Index	PPI Index
2010	541	1.05
2011	562	1.01
2012	562	1.01
2013	565	1.00

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF DISTRIBUTION DEMAND-RELATED MARGINAL COSTS

Line No.	Description	Rate 60	Rate 70 < 500 cu ft	Rate 70 > 500 cu ft	Rates 71/81	Rates 85/82
1	Distribution Demand-Related Marginal Cost ($/Mcfd) 1/	$1,556.81	$1,049.96	$186.22	$52.59	$22.43
2	General and Common Plant Allocation (Line 1 x 27.26%) 2/	424.39	286.22	50.76	14.34	6.11
3	Marginal Cost Including General Plant	1,981.20	1,336.18	236.98	66.93	28.54
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	8.655%	8.655%	8.655%	8.655%	8.655%
5	Annual Levelized Amount (Line 3 x Line 4)	171.47	115.65	20.51	5.79	2.47
6	Demand-Related Operation & Maintenance Expense (Line 3 x .78%) 4/	15.45	10.42	1.85	0.52	0.22
7	Demand-Related Administrative & General Allocation (Line 3 x 0.41%) 5/	8.12	5.48	0.97	0.27	0.12
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	195.04	131.55	23.33	6.58	2.81
	Taxes Other Than Income Taxes (Excl. Revenue-Related)					
9	Property Taxes (Line 3 x 0.60%) 6/	11.89	8.02	1.42	0.40	0.17
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	0.98	0.66	0.12	0.03	0.01
11	Sub-Total Taxes Other	12.87	8.68	1.54	0.43	0.18
	Working Capital Requirement					
12	Materials and Supplies (Line 3 x .14%) 2/	2.77	1.87	0.33	0.09	0.04
13	Prepayments (Line 3 x 0.01%) 2/	0.20	0.13	0.02	0.01	0
14	Total Working Capital	2.97	2.00	0.35	0.10	0.04
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.36	0.24	0.04	0.01	0
17	Sub-Total (Line 8 + Line 11 + Line 16)	208.27	140.47	24.91	7.02	2.99
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.79	0.53	0.09	0.03	0.01
19	Total Demand-Related Marginal Cost of Distribution	$209.06	$141.00	$25.00	$7.05	$3.00

1/ Exhibit No. __(TAA-3), page 7 and page 13.
2/ Exhibit No. __(TAA-3), page 14.
3/ Exhibit No. __(TAA-3), page 16.
4/ Exhibit No. __(TAA-3), page 17.
5/ Exhibit No. __(TAA-3), page 24.
6/ Exhibit No. __(TAA-3), page 26.
7/ Exhibit No. __(TAA-3), page 15.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Montana Demand-Related
Distribution Plant Additions

Project Number	Project Year	Incremental Capacity (Mcfd)	Investment in Gas Distribution System	Restated in 1/1/14 Dollars 1/
(1)	(2)	(3)	(4)	(5)
1	2011	415	$15,861	$16,180
2	2011	638	13,160	13,424
3	2011	800	19,620	20,014
4	2011	971	70,000	71,406
5	2011	1,613	26,350	26,879
6	2011	1,693	28,000	28,562
7	2011	3,000	145,000	147,912
8	2011	4,000	65,000	66,305
9	2011	12,000	64,000	65,285
	Total	24,715	$431,130	$439,787

Demand-Related Distribution Investment per Additional Mcfd of Distribution Capacity	$17.79

1/ Plant additions in Column (4) are restated in 1/1/14 dollars in Column (5) using the Producer Price Index for Metals and Metal Products (weighted 50%) and the Producer Price Index for Unit Labor Costs - Non Farm (weighted 50%).

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF CUSTOMER-RELATED MARGINAL COSTS
RESIDENTIAL - RATE 60

Line No.	Description	Service Line	Meters/ Regulators	Customer Accounting Info, Sales	Total
1	Customer-Related Marginal Cost ($/Customer) 1/	$560.03	$223.40	--	$783.43
2	General and Common Plant Allocation @ 27.26% 2/	152.66	60.90	--	213.56
3	Marginal Cost Including General Plant	$712.69	$284.30	$0.00	$996.99
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	10.151%	9.356%	--	--
5	Annual Levelized Amount (Line 3 x Line 4)	72.35	26.60	0	98.95
6	Customer-Related Operation & Maintenance Expense Distrib. O&M @ 2.84%, 3.24% 4/ 8/	15.90	7.24	26.31	$49.45
7	Customer-Related Administrative & General Allocation (Line 3 x 2.48%) 5/	17.67	7.05	--	$24.72
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	105.92	40.89	26.31	$173.12
	Taxes Other Than Income Taxes (Excl. Revenue-Related)				
9	Property Taxes (Line 3 x 0.60%) 6/	4.28	1.71	--	$5.99
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	1.39	0.59	1.09	$3.07
11	Sub-Total Taxes Other	5.67	2.30	1.09	9.06
	Working Capital Requirement				
12	Materials and Supplies (Line 3 x 0.14%) 2/	1.00	0.40	0	$1.40
13	Prepayments (Line 3 x 0.01%) 2/	0.07	0.03	0	$0.10
14	Total Working Capital	1.07	0.43	0	$1.50
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.13	0.05	0	$0.18
17	Sub-Total (Line 8 + Line 11 + Line 16)	111.72	43.24	27.40	$182.36
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.42	0.16	0.10	$0.68
19	Total Customer-Related Marginal Cost ($/year) (Line 17 + Line 18)	112.14	43.40	27.50	$183.04
20	Customer-Related Marginal Cost ($/month)	$9.35	$3.62	$2.29	$15.26

1/ Exhibit No. __ (TAA-3), page 13.
2/ Exhibit No. __ (TAA-3), page 14.
3/ Exhibit No. __ (TAA-3), page 16.
4/ Exhibit No. __ (TAA-3), page 17.
5/ Exhibit No. __ (TAA-3), page 24.
6/ Exhibit No. __ (TAA-3), page 26.
7/ Exhibit No. __ (TAA-3), page 15.
8/ Exhibit No. __ (TAA-3), page 27.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF CUSTOMER-RELATED MARGINAL COSTS
FIRM GENERAL - RATE 70 AND RATE 72
SMALL METERS

Line No.	Description	Service Line	Meters/ Regulators	Customer Accounting Info, Sales	Total
1	Customer-Related Marginal Cost ($/Customer) 1/	$984.40	$248.90	--	$1,233.30
2	General and Common Plant Allocation @ 27.26% 2/	268.35	67.85	--	336.20
3	Marginal Cost Including General Plant	$1,252.75	$316.75	$0.00	$1,569.50
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	10.151%	9.356%	--	--
5	Annual Levelized Amount (Line 3 x Line 4)	127.17	29.64	0	156.81
6	Customer-Related Operation & Maintenance Expense Distrib. O&M @ 2.84%, 3.24% 4/ 8/	27.96	8.06	28.84	64.86
7	Customer-Related Administrative & General Allocation (Line 3 x 2.48%) 5/	31.07	7.86	--	38.93
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	186.20	45.56	28.84	260.60
	Taxes Other Than Income Taxes (Excl. Revenue-Related)				
9	Property Taxes (Line 3 x 0.60%) 6/	7.52	1.90	--	9.42
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	2.45	0.66	1.20	4.31
11	Sub-Total Taxes Other	9.97	2.56	1.20	13.73
	Working Capital Requirement				
12	Materials and Supplies (Line 3 x 0.14%) 2/	1.75	0.44	0	2.19
13	Prepayments (Line 3 x 0.01%) 2/	0.13	0.03	0	0.16
14	Total Working Capital	1.88	0.47	0	2.35
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.23	0.06	0	0.29
17	Sub-Total (Line 8 + Line 11 + Line 16)	196.40	48.18	30.04	274.62
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.75	0.18	0.11	1.04
19	Total Customer-Related Marginal Cost ($/year) (Line 17 + Line 18)	197.15	48.36	30.15	275.66
20	Customer-Related Marginal Cost ($/month)	$16.43	$4.03	$2.51	$22.97

1/ Exhibit No. __ (TAA-3), page 13.
2/ Exhibit No. __ (TAA-3), page 14.
3/ Exhibit No. __ (TAA-3), page 16.
4/ Exhibit No. __ (TAA-3), page 17.
5/ Exhibit No. __ (TAA-3), page 24.
6/ Exhibit No. __ (TAA-3), page 26.
7/ Exhibit No. __ (TAA-3), page 15.
8/ Exhibit No. __ (TAA-3), page 27.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF CUSTOMER-RELATED MARGINAL COSTS
FIRM GENERAL - RATE 70 AND RATE 72
LARGE METERS

Line No.	Description	Service Line	Meters/ Regulators	Customer Accounting Info, Sales	Total
1	Customer-Related Marginal Cost ($/Customer) 1/	$984.40	$2,035.10	--	$3,019.50
2	General and Common Plant Allocation @ 27.26% 2/	268.35	554.77	--	823.12
3	Marginal Cost Including General Plant	$1,252.75	$2,589.87	$0.00	$3,842.62
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	10.151%	9.356%	--	--
5	Annual Levelized Amount (Line 3 x Line 4)	127.17	242.31	0	369.48
6	Customer-Related Operation & Maintenance Expense Distrib. O&M @ 2.84%, 3.24% 4/ 8/	27.96	65.94	230.92	324.82
7	Customer-Related Administrative & General Allocation (Line 3 x 2.48%) 5/	31.07	64.23	--	95.30
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	186.20	372.48	230.92	789.60
	Taxes Other Than Income Taxes (Excl. Revenue-Related)				
9	Property Taxes (Line 3 x 0.60%) 6/	7.52	15.54	--	23.06
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	2.45	5.40	9.58	17.43
11	Sub-Total Taxes Other	9.97	20.94	9.58	40.49
	Working Capital Requirement				
12	Materials and Supplies (Line 3 x 0.14%) 2/	1.75	3.63	0	5.38
13	Prepayments (Line 3 x 0.01%) 2/	0.13	0.26	0	0.39
14	Total Working Capital	1.88	3.89	0	5.77
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.23	0.47	0	0.70
17	Sub-Total (Line 8 + Line 11 + Line 16)	196.40	393.89	240.50	830.79
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.75	1.50	0.91	3.16
19	Total Customer-Related Marginal Cost ($/year) (Line 17 + Line 18)	197.15	395.39	241.41	833.95
20	Customer-Related Marginal Cost ($/month)	$16.43	$32.95	$20.12	$69.50

1/ Exhibit No. __ (TAA-3), page 13.
2/ Exhibit No. __ (TAA-3), page 14.
3/ Exhibit No. __ (TAA-3), page 16.
4/ Exhibit No. __ (TAA-3), page 17.
5/ Exhibit No. __ (TAA-3), page 24.
6/ Exhibit No. __ (TAA-3), page 26.
7/ Exhibit No. __ (TAA-3), page 15.
8/ Exhibit No. __ (TAA-3), page 27.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF CUSTOMER-RELATED MARGINAL COSTS
SMALL INTERRUPTIBLE - RATE 71 AND RATE 81

Line No.	Description	Service Line	Meters/ Regulators	Customer Accounting Info, Sales	Total
1	Customer-Related Marginal Cost ($/Customer) 1/	$984.40	$8,204.66	--	$9,189.06
2	General and Common Plant Allocation @ 27.26% 2/	268.35	2,236.59	--	2,504.94
3	Marginal Cost Including General Plant	$1,252.75	$10,441.25	$0.00	$11,694.00
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	10.151%	9.356%	--	--
5	Annual Levelized Amount (Line 3 x Line 4)	127.17	976.88	0	1,104.05
6	Customer-Related Operation & Maintenance Expense Distrib. O&M @ 2.84%, 3.24% 4/ 8/	27.96	265.83	927.59	1,221.38
7	Customer-Related Administrative & General Allocation (Line 3 x 2.48%) 5/	31.07	258.94	--	290.01
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	186.20	1,501.65	927.59	2,615.44
	Taxes Other Than Income Taxes (Excl. Revenue-Related)				
9	Property Taxes (Line 3 x 0.60%) 6/	7.52	62.65	--	70.17
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	2.45	21.78	38.49	62.72
11	Sub-Total Taxes Other	9.97	84.43	38.49	132.89
	Working Capital Requirement				
12	Materials and Supplies (Line 3 x 0.14%) 2/	1.75	14.62	0	16.37
13	Prepayments (Line 3 x 0.01%) 2/	0.13	1.04	0	1.17
14	Total Working Capital	1.88	15.66	0	17.54
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.23	1.91	0	2.14
17	Sub-Total (Line 8 + Line 11 + Line 16)	196.40	1,587.99	966.08	2,750.47
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.75	6.03	3.67	10.45
19	Total Customer-Related Marginal Cost ($/year) (Line 17 + Line 18)	197.15	1,594.02	969.75	2,760.92
20	Customer-Related Marginal Cost ($/month)	$16.43	$132.84	$80.81	$230.08

1/ Exhibit No. __ (TAA-3), page 13.
2/ Exhibit No. __ (TAA-3), page 14.
3/ Exhibit No. __ (TAA-3), page 16.
4/ Exhibit No. __ (TAA-3), page 17.
5/ Exhibit No. __ (TAA-3), page 24.
6/ Exhibit No. __ (TAA-3), page 26.
7/ Exhibit No. __ (TAA-3), page 15.
8/ Exhibit No. __ (TAA-3), page 27.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF CUSTOMER-RELATED MARGINAL COSTS
LARGE INTERRUPTIBLE - RATE 82 AND RATE 85

Line No.	Description	Service Line	Meters/ Regulators	Customer Accounting Inf. & Sales	Total
1	Customer-Related Marginal Cost ($/Customer) 1/	$4,267.08	$14,029.44	--	$18,296.52
2	General and Common Plant Allocation @ 27.26% 2/	1,163.21	3,824.43	--	4,987.64
3	Marginal Cost Including General Plant	$5,430.29	$17,853.87	$0.00	$23,284.16
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	10.151%	9.356%	--	--
5	Annual Levelized Amount (Line 3 x Line 4)	551.23	1,670.41	0	2,221.64
6	Customer-Related Operation & Maintenance Expense Distrib. O&M @ 2.84%, 3.24% 4/ 8/	121.19	454.55	1,380.20	1,955.94
7	Customer-Related Administrative & General Allocation (Line 3 x 2.48%) 5/	134.67	442.78	--	577.45
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	807.09	2,567.74	1,380.20	4,755.03
	Taxes Other Than Income Taxes (Excl. Revenue-Related)				
9	Property Taxes (Line 3 x 0.60%) 6/	32.58	107.12	--	139.70
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	10.62	37.24	57.28	105.14
11	Sub-Total Taxes Other	43.20	144.36	57.28	244.84
	Working Capital Requirement				
12	Materials and Supplies (Line 3 x 0.14%) 2/	7.60	25.00	0	32.60
13	Prepayments (Line 3 x 0.01%) 2/	0.54	1.79	0	2.33
14	Total Working Capital	8.14	26.79	0	34.93
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.99	3.27	0	4.26
17	Sub-Total (Line 8 + Line 11 + Line 16)	851.28	2,715.37	1,437.48	5,004.13
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	3.23	10.32	5.46	19.01
19	Total Customer-Related Marginal Cost ($/year) (Line 17 + Line 18)	854.51	2,725.69	1,442.94	5,023.14
20	Customer-Related Marginal Cost ($/month)	$71.21	$227.14	$120.25	$418.60

1/ Exhibit No. __ (TAA-3), page 13.
2/ Exhibit No. __ (TAA-3), page 14.
3/ Exhibit No. __ (TAA-3), page 16.
4/ Exhibit No. __ (TAA-3), page 17.
5/ Exhibit No. __ (TAA-3), page 24.
6/ Exhibit No. __ (TAA-3), page 26.
7/ Exhibit No. __ (TAA-3), page 15.
8/ Exhibit No. __ (TAA-3), page 27.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

MARGINAL CUSTOMER-RELATED DISTRIBUTION INVESTMENT

	Customer Class				
	Residential Rate 60	Firm General Small Rates 70/72	Firm General Large Rates 70/72	Small Interruptible Rates 71/81	Large Interruptible Rates 82/85
Marginal Customer Costs (1/1/12 Dollars)					
Main	$1,037	$1,556	$1,556	$1,556	$4,470
Service Line	$549	$965	$965	$965	$4,183
Meter & Regulator	$219	$244	$1,995	$8,043	$13,753
Index to Adjust to 1/1/14 1/	1.0201	1.0201	1.0201	1.0201	1.0201
Marginal Customer Costs (Restated in 1/1/14 Dollars)					
Main	$1,057.84	$1,587.28	$1,587.28	$1,587.28	$4,559.85
Service Line	$560.03	$984.40	$984.40	$984.40	$4,267.08
Meter & Regulator	$223.40	$248.90	$2,035.10	$8,204.66	$14,029.44
Customers	70,161	6,547	2,153	44	5
Total Main Investment	$74,219,112.24	$10,391,922.16	$3,417,413.84	$69,840.32	$22,799.25
Peak Day Demand	48,225	10,068	20,290	2,007	4,914
Cost Per Peak Day	$1,539.02	$1,032.17	$168.43	$34.80	$4.64

1/ Based on IHS Global Insight

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DEVELOPMENT OF GENERAL PLANT & MATERIAL AND SUPPLIES OVERHEAD FACTOR

	2007	2008	2009	2010	2011	Average
Average General & Common Plant	$15,403,184	$17,882,572	$19,271,962	$19,280,683	$19,369,918	$18,241,664
Avg Production & Distribution Plant 1/	58,799,745	63,534,739	66,987,200	70,543,811	74,712,467	66,915,592
Percent of General to Prod & Distr	26.20%	28.15%	28.77%	27.33%	25.93%	27.26%

Material and Supplies per embedded cost study 2/	$533,337	0.14%
Prepayments - per embedded cost study (insurance only) 2/	$25,908	0.01%
Total Gas Plant (Trended Original Cost Basis) 1/	$371,127,422	

1/ Original cost basis. Exhibit No. __ (TAA-3) page 5 and page 20.
2/ Statement L, Schedule L-2, page 2.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

BASIS FOR COMPONENTS OF MARGINAL CARRYING CHARGE

I -- Cost of Capital

Type	Capital Ratio	Cost	Weighted Cost
Long-Term Debt	39.691%	6.846%	2.717%
Short Term Debt	4.750%	1.399%	0.066%
Preferred Stock	2.172%	4.583%	0.100%
Common Equity	53.387%	10.500%	5.606%
Total	100.000%		8.489%

II -- Depreciation Expense

Plant Item	Book Life Years 1/	Salvage Value (%) 1/	Tax Life (years)
Mains	47	-50.00%	20.00
Services	40	-200.00%	20.00
Meters/Regulators	35	-15.00%	20.00

III -- Other Components

1. Composite Federal and State Income Tax Rate: 39.3875%.
2. Insurance: Included in Administrative and General Expense.
3. Property Taxes: Included in Annualization Schedules.

IV -- Required Return on Working Capital

		Total	LT Debt	ST Debt	Preferred	Equity
Required Revenue		12.197%	2.717%	0.066%	0.165%	9.249%
Tax @	39.3875%	3.708%			0.065%	3.643%
Rate of Return		8.489%	2.717%	0.066%	0.100%	5.606%

1/ Per AUS Consultants, Depreciation Study for MDU - as of December 31, 2008

CARRYING CHARGE CALCULATION

d=Marginal Carry Charge (Cost of Capital) 1/	8.489%
i=Inflation Rate	1.50%
n=Book Life-Average Economic Life	
Book Life - Years 1/	
Mains:	47
Services:	40
Meters/Regulators:	35
Sum of P.W. Values 2/	
Mains:	120.194
Services	137.148
Meters/Regulators	122.663

$dn = ((1+d)/(1+i))-1$	0.068857

$CRF\ real = ((dn*((1+dn)^n))/((1+dn)^n)-1)$

Mains	0.072006
Services	0.074016
Meters/Reg	0.076273

Levelized Fixed Charge Rate 3/

Mains	8.655%
Services	10.151%
Meters/Regulators	9.356%

1/ Exhibit No. __(TAA-3) page 15
2/ Levelized Fixed Charge worksheets
3/ Real Capital Recovery Factor * Sum of P.W. Values

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION PLANT - FUNCTIONALIZED BY ACCOUNT
TRENDED ORIGINAL COST BASIS

		Five-Year Average 1/			Demand-Related		Customer-Related		
Acct	Description	Total	Demand	Customer	Mains	System Other	Mains	Services	Meters & Regulators
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(9)	(10)	(11)
	Distribution Plant								
374	Land	$37,497	$37,497	$0		$37,497			
375	Structures & Improvements	1,132,526	1,132,526	0		1,132,526			
376	Mains	172,038,302	172,038,302	0	172,038,302		0		
378	Meas. & Regul. Sta. Equip. - Gen.	2,728,773	2,728,773	0		2,728,773			
379	Meas. & Regul. Sta. Equip. - Ind.	629,813	629,813	0		629,813			0
380	Services	64,123,444	0	64,123,444				64,123,444	
381	Meters	41,258,604	0	41,258,604					41,258,604
383	House Regulators	5,726,614	0	5,726,614					5,726,614
385	Indust. Meas. & Regul. Equipment	1,121,806	1,121,806	0		1,121,806			
387	Cathodic Protection & Other	2,791,959	2,791,959	0	2,791,959		0		
	Total Distribution Plant	$291,589,338	$180,480,676	$111,108,662	$174,830,261	$5,650,415	$0	$64,123,444	$46,985,218
	O&M / Distribution Plant 2/		0.78%	3.01%	0.67%	4.27%		2.84%	3.24%

Demand-Related	
Mains & System Other	0.78%
Customer-Related	
Service Stubs & Services	2.84%
Meters & Regulators	3.24%

1/ Exhibit No.___(TAA-3) page 18.
2/ O&M from Exhibit No.___(TAA-3) page 21.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION PLANT - CLASSIFIED BY ACCOUNT
FIVE-YEAR AVERAGE BY ACCOUNT
TRENDED ORIGINAL COST BASIS

		2007			2008			2009		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Distribution Plant									
374	Land	$36,626	$36,626	$0	$37,059	$37,059	$0	$37,059	$37,059	$0
375	Structures & Improvements	1,156,487	1,156,487	0	1,181,532	1,181,532	0	1,156,487	1,156,487	0
376	Mains	167,466,209	167,466,209	0	168,621,948	168,621,948	0	174,724,590	174,724,589	0
378	Meas. & Regul. Sta. Equip. - Gen.	2,855,530	2,855,530	0	2,788,873	2,788,873	0	2,720,933	2,720,933	0
379	Meas. & Regul. Sta. Equip. - Ind.	790,299	790,299	0	776,054	776,054	0	527,569	527,569	0
380	Services	59,098,763	0	59,098,763	60,861,520	0	60,861,520	63,544,619	0	63,544,619
381	Meters	35,025,687	0	35,025,687	39,840,985	0	39,840,985	42,842,511	0	42,842,511
383	House Regulators	5,701,141	0	5,701,141	5,550,053	0	5,550,053	5,477,863	0	5,477,863
385	Indust. Meas. & Regul. Equipment	1,171,335	1,171,335	0	1,146,463	1,146,463	0	1,119,424	1,119,424	0
387	Cathodic Protection & Other	2,822,298	2,822,299	0	2,699,189	2,699,190	0	2,673,426	2,673,425	0
	Total Distribution Plant	276,124,375	176,298,785	99,825,591	283,503,676	177,251,119	106,252,558	294,824,481	182,959,486	111,864,993

		2010			2011			Five-Year Average		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
	Distribution Plant									
374	Land	$37,934	$37,934	$0	$38,808	$38,808	$0	$37,497	$37,497	$0
375	Structures & Improvements	1,109,752	1,109,752	0	1,058,370	1,058,370	0	1,132,526	1,132,526	0
376	Mains	177,564,613	177,564,613	0	171,814,152	171,814,152	0	172,038,302	172,038,302	0
378	Meas. & Regul. Sta. Equip. - Gen.	2,703,538	2,703,538	0	2,574,991	2,574,991	0	2,728,773	2,728,773	0
379	Meas. & Regul. Sta. Equip. - Ind.	527,569	527,569	0	527,573	527,573	0	629,813	629,813	0
380	Services	67,514,375	0	67,514,375	69,597,941	0	69,597,941	64,123,444	0	64,123,444
381	Meters	43,221,206	0	43,221,206	45,362,631	0	45,362,631	41,258,604	0	41,258,604
383	House Regulators	5,755,394	0	5,755,394	6,148,620	0	6,148,620	5,726,614	0	5,726,614
385	Indust. Meas. & Regul. Equipment	1,113,139	1,113,139	0	1,058,667	1,058,667	0	1,121,806	1,121,806	0
387	Cathodic Protection & Other	2,774,715	2,774,715	0	2,990,169	2,990,169	0	2,791,959	2,791,959	0
	Total Distribution Plant	302,322,235	185,831,260	116,490,975	301,171,922	180,062,730	121,109,192	291,589,338	180,480,676	111,108,662

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

TRENDING FACTORS FOR
DISTRIBUTION PLANT BY ACCOUNT

		Trending Factor to January 1, 2014 for Average Plant in Year				
Acct	Description	2007	2008	2009	2010	2011
	Distribution Plant					
374	Land	1.000	1.000	1.000	1.000	1.000
375	Structures & Improvements	5.926	6.054	5.926	5.686	5.423
376	Mains	6.582	6.365	6.351	6.307	6.003
378	Meas. & Regul. Sta. Equip. - Gen.	5.022	4.916	4.762	4.699	4.469
379	Meas. & Regul. Sta. Equip. -City Gate	6.164	6.052	4.115	4.115	4.115
380	Services	3.753	3.602	3.524	3.524	3.402
381	Meters	2.560	2.465	2.465	2.465	2.504
383	House Regulators	3.417	3.225	3.065	3.085	3.045
385	Indust. Meas. & Regul. Equipment	6.334	6.200	6.006	5.926	5.636
387	Cathodic Protection & Other	2.827	2.701	2.638	2.577	2.526

GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION PLANT - CLASSIFIED BY ACCOUNT
FIVE-YEAR AVERAGE BY ACCOUNT
ORIGINAL COST BASIS

		2007			2008			2009		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Distribution Plant									
374	Land	$36,626	$36,626	$0	$37,059	$37,059	$0	$37,059	$37,059	$0
375	Structures & Improvements	195,164	195,164	0	195,164	195,164	0	195,164	195,164	0
376	Mains	25,444,903	25,444,903	0	26,492,694	26,492,694	0	27,510,030	27,510,030	0
378	Meas. & Regul. Sta. Equip. - Gen.	568,572	568,572	0	567,347	567,347	0	571,344	571,344	0
379	Meas. & Regul. Sta. Equip. -City Gate	128,221	128,221	0	128,221	128,221	0	128,221	128,221	0
380	Services	15,746,044	0	15,746,044	16,898,851	0	16,898,851	18,030,301	0	18,030,301
381	Meters	13,679,938	0	13,679,938	16,161,628	0	16,161,628	17,379,207	0	17,379,207
383	House Regulators	1,668,413	0	1,668,413	1,720,842	0	1,720,842	1,787,350	0	1,787,350
385	Indust. Meas. & Regul. Equipment	184,923	184,923	0	184,923	184,923	0	186,374	186,374	0
386	Other Property on Customers Premise	148,674	0	148,674	148,674	0	148,674	148,674	0	148,674
387	Cathodic Protection & Other	998,267	998,267	0	999,336	999,336	0	1,013,476	1,013,476	0
	Total Distribution Plant	$58,799,745	$27,556,676	$31,243,069	$63,534,739	$28,604,744	$34,929,995	$66,987,200	$29,641,668	$37,345,532

		2010			2011			Five-Year Average		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
	Distribution Plant									
374	Land	$37,934	$37,934	$0	$38,808	$38,808	$0	$37,497	$37,497	$0
375	Structures & Improvements	195,164	195,164	0	195,164	195,164	0	195,164	195,164	0
376	Mains	28,152,271	28,152,271	0	28,623,324	28,623,324	0	27,244,644	27,244,644	0
378	Meas. & Regul. Sta. Equip. - Gen.	575,341	575,341	0	576,181	576,181	0	571,757	571,757	0
379	Meas. & Regul. Sta. Equip. -City Gate	128,221	128,221	0	128,222	128,222	0	128,221	128,221	0
380	Services	19,156,689	0	19,156,689	20,458,685	0	20,458,685	18,058,114	0	18,058,114
381	Meters	17,532,826	0	17,532,826	18,117,820	0	18,117,820	16,574,284	0	16,574,284
383	House Regulators	1,865,699	0	1,865,699	2,019,420	0	2,019,420	1,812,345	0	1,812,345
385	Indust. Meas. & Regul. Equipment	187,825	187,825	0	187,825	187,825	0	186,374	186,374	0
386	Other Property on Customers Premise	148,674	0	148,674	148,674	0	148,674	148,674	0	148,674
387	Cathodic Protection & Other	1,076,776	1,076,776	0	1,183,575	1,183,575	0	1,054,286	1,054,286	0
	Total Distribution Plant	$69,057,420	$30,353,532	$38,703,888	$71,677,698	$30,933,099	$40,744,599	$66,011,360	$29,417,943	$36,593,417

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION O&M EXPENSES - FUNCTIONALIZED BY ACCOUNT

		Five-Year Average (Weighted by Year to 1/1/14) 1/			Demand-Related 2/		Customer-Related 2/		
Acct	Description	Total	Demand	Customer	Mains	System Other	Mains	Services	Meters & Regulators
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Distribution Expenses								
	Operation								
870	Supervision & Engineering	$529,967	$0	$529,967	$0	$0	$0	$310,241	$219,726
871	Load Dispatching	72,787	72,787	0		72,787			
874	Mains and Services	1,180,471	688,419	492,053	688,419		0	492,053	
875	Meas. & Regul. Stations - General	43,528	43,528	0		43,528			
876	Meas. & Regul. Stations - Industrial	13,129	13,129	0		13,129			
878	Meters & House Regulators	338,924	0	338,924					338,924
879	Customer Installation	677,200	0	677,200				390,828	286,372
880	Other Expenses	967,597	333,582	634,014	280,786	52,796	0	371,149	262,865
881	Rents	43,150	14,876	28,274	12,522	2,354	0	16,551	11,723
	Total Operation	3,866,753	1,166,321	2,700,432	981,727	184,594	0	1,580,822	1,119,610
	Maintenance								
885	Supervision & Engineering	145,767	42,902	102,865	32,803	10,099	0	38,501	64,364
886	Structures & Improvements	1,412	1,412	0		1,412			
887	Mains	124,862	124,862	0	124,862				
889	Meas. & Regul. Stations - General	22,239	22,239	0		22,239			
890	Meas. & Regul. Stations - Industrial	14,792	14,792	0		14,792			0
892	Services	172,841	0	172,841				172,841	
893	Meters & House Regulators	288,942	0	288,942					288,942
894	Other	115,605	34,024	81,580	26,015	8,009	0	30,535	51,045
	Total Maintance	886,460	240,231	646,228	183,680	56,551		241,877	404,351
	Total Distribution O&M	$4,753,213	$1,406,552	$3,346,660	$1,165,407	$241,145	$0	$1,822,699	$1,523,961

1/ Exhibit No. ___(TAA-3) page 23.
2/ Allocated on the basis of distribution plant (Exhibit No.___(TAA-3), page 18.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION O&M EXPENSES - CLASSIFIED BY ACCOUNT
FIVE-YEAR AVERAGE BY ACCOUNT

		2007			2008			2009		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Distribution Expenses									
	Operation									
870	Supervision & Engineering	$534,905	$0	$534,905	$548,565	$0	$548,565	$392,079	$0	$392,079
871	Load Dispatching	60,758	60,758	0	63,883	63,883	0	63,895	63,895	0
874	Mains and Services	1,059,279	617,743	441,536	1,099,603	641,259	458,344	1,046,324	610,188	436,136
875	Meas. & Regul. Stations - General	25,599	25,599	0	37,331	37,331	0	57,983	57,983	0
876	Meas. & Regul. Stations - Industrial	11,408	11,408	0	10,506	10,506	0	15,508	15,508	0
878	Meters & House Regulators	283,849	0	283,849	289,540	0	289,540	343,353	0	343,353
879	Customer Installation	746,562	0	746,562	836,606	0	836,606	507,304	0	507,304
880	Other Expenses	925,890	319,204	606,686	957,235	330,010	627,225	932,102	321,345	610,757
881	Rents	53,692	18,510	35,182	39,347	13,565	25,782	39,277	13,541	25,736
	Total Operation	3,701,942	1,053,222	2,648,720	3,882,616	1,096,554	2,786,062	3,397,825	1,082,460	2,315,365
	Maintenance									
885	Supervision & Engineering	166,558	49,021	117,537	165,647	48,753	116,894	98,657	29,037	69,620
886	Structures & Improvements	712	712	0	741	741	0	2,562	2,562	0
887	Mains	100,744	100,744	0	104,600	104,600	0	95,168	95,168	0
889	Meas. & Regul. Stations - General	28,991	28,991	0	21,578	21,578	0	14,264	14,264	0
890	Meas. & Regul. Stations - Industrial	13,188	13,188	0	17,357	17,357	0	15,739	15,739	0
892	Services	113,980	0	113,980	183,513	0	183,513	191,693	0	191,693
893	Meters & House Regulators	182,990	0	182,990	295,566	0	295,566	313,723	0	313,723
894	Other	104,886	30,870	74,016	90,278	26,570	63,708	116,222	34,206	82,016
	Total Maintance	712,049	223,526	488,523	879,280	219,599	659,681	848,028	190,976	657,052
	Total Distribution O&M	$4,413,991	$1,276,748	$3,137,243	$4,761,896	$1,316,153	$3,445,743	$4,245,853	$1,273,436	$2,972,417
	Index to Adjust to 1/1/14 1/	1.0890	1.0890	1.0890	1.0697	1.0697	1.0697	1.0583	1.0583	1.0583
	Adjusted to 1/1/14 Dollars	$4,806,836	$1,390,379	$3,416,458	$5,093,800	$1,407,889	$3,685,911	$4,493,386	$1,347,677	$3,145,709

1/ Employment Cost Index - Global Insight

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DISTRIBUTION O&M EXPENSES - CLASSIFIED BY ACCOUNT
FIVE-YEAR AVERAGE BY ACCOUNT

		2010			2011			Five-Year Average (Weighted by Adj. Factor to 1/1/14)		
Acct	Description	Total	Demand	Customer	Total	Demand	Customer	Total	Demand	Customer
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Distribution Expenses									
	Operation									
870	Supervision & Engineering	$471,700	$0	$471,700	$514,850	$0	$514,850	$529,967	$0	$529,967
871	Load Dispatching	75,294	75,294	0	74,482	74,482	0	72,787	72,787	0
874	Mains and Services	1,143,489	666,852	476,637	1,138,366	663,865	474,501	1,180,471	688,419	492,053
875	Meas. & Regul. Stations - General	47,011	47,011	0	34,815	34,815	0	43,528	43,528	0
876	Meas. & Regul. Stations - Industrial	9,177	9,177	0	14,521	14,521	0	13,129	13,129	0
878	Meters & House Regulators	391,269	0	391,269	267,551	0	267,551	338,924	0	338,924
879	Customer Installation	517,434	0	517,434	538,992	0	538,992	677,200	0	677,200
880	Other Expenses	851,664	293,614	558,050	832,223	286,912	545,311	967,597	333,582	634,014
881	Rents	34,763	11,985	22,778	33,379	11,508	21,871	43,150	14,876	28,274
	Total Operation	3,541,801	1,103,933	2,437,868	3,449,179	1,086,103	2,363,076	3,866,753	1,166,321	2,700,432
	Maintenance									
885	Supervision & Engineering	115,484	33,989	81,495	130,671	38,459	92,212	145,767	42,902	102,865
886	Structures & Improvements	1,394	1,394	0	1,179	1,179	0	1,412	1,412	0
887	Mains	141,425	141,425	0	138,093	138,093	0	124,862	124,862	0
889	Meas. & Regul. Stations - General	10,292	10,292	0	28,158	28,158	0	22,239	22,239	0
890	Meas. & Regul. Stations - Industrial	6,885	6,885	0	15,721	15,721	0	14,792	14,792	0
892	Services	160,415	0	160,415	155,111	0	155,111	172,841	0	172,841
893	Meters & House Regulators	268,882	0	268,882	284,028	0	284,028	288,942	0	288,942
894	Other	105,407	31,023	74,384	120,738	35,535	85,203	115,605	34,024	81,580
	Total Maintance	810,184	225,008	585,176	873,699	257,145	616,554	886,460	240,231	646,228
	Total Distribution O&M	4,351,985	1,328,941	3,023,044	4,322,878	1,343,248	2,979,630	4,753,213	1,406,552	3,346,660
	Index to Adjust to 1/1/14 1/	1.0857	1.0857	1.0857	1.0750	1.0750	1.0750			
	Adjusted to 1/1/14 Dollars	$4,724,950	$1,442,831	$3,282,119	$4,647,094	$1,443,992	$3,203,102	$4,753,213	$1,406,554	$3,346,660

1/ Employment Cost Index - Global Insight

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DEVELOPMENT OF ADMINISTRATIVE & GENERAL EXPENSE OVERHEAD ALLOCATION

	2007	2008	2009	2010	2011	Average
Average Plant in Service	(Trended Original Cost Basis)					
Distribution (Accts 374-398)						
Demand/Energy-Related 1/	$176,298,785	$177,251,119	$182,959,486	$185,831,260	$180,062,730	$180,480,676
Customer-Related 1/	99,825,591	106,252,558	111,864,993	116,490,975	121,109,192	111,108,662
Total Distribution	276,124,376	283,503,677	294,824,479	302,322,235	301,171,922	291,589,338
General & Common (Accts 389-398)						
Demand/Energy-Related	46,190,282	49,896,190	52,637,444	50,787,683	46,690,266	49,240,373
Customer-Related	26,154,305	29,910,095	32,183,558	31,836,983	31,403,613	30,297,711
Total General/Common 2/	72,344,587	79,806,285	84,821,003	82,624,667	78,093,879	79,538,084
Total Average Plant						
Demand/Energy-Related	222,489,067	227,147,309	235,596,930	236,618,943	226,752,996	229,721,049
Customer-Related	125,979,896	136,162,653	144,048,551	148,327,958	152,512,805	141,406,373
Total	$348,468,963	$363,309,962	$379,645,481	$384,946,901	$379,265,801	$371,127,422
A&G as a Percent of Average Plant 3/						
Demand/Energy-Related	0.45%	0.42%	0.38%	0.35%	0.43%	0.41%
Customer-Related	3.18%	2.92%	2.22%	1.94%	2.27%	2.48%
Overall	1.44%	1.36%	1.08%	0.96%	1.17%	1.20%

1/ Exhibit No. __ (TAA-3), page 18.
2/ Trended original cost (TOC) for general and common plant estimated by multiplying TOC of distribution plant by percent of general and common to distribution plant.
3/ A&G expenses from Exhibit No. __(TAA-3) page 25 as a percentage of total average plant.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

DEVELOPMENT OF ADMINISTRATIVE & GENERAL EXPENSE OVERHEAD ALLOCATION

	2007	2008	2009	2010	2011	Average
Operation & Maintenance Expense						
(Excluding Purchased Gas & A&G)						
Production (Accts 804-813)	$76,794	$79,239	$70,111	$89,297	$73,609	
Distribution (Accts 870-894)						
Demand/Energy 1/	1,276,748	1,316,153	1,273,436	1,328,941	1,343,248	
Customer 1/	3,137,243	3,445,743	2,972,417	3,023,044	2,979,630	
Total Distribution	4,413,991	4,761,896	4,245,853	4,351,985	4,322,878	
Customer (Accts 901-916)	2,272,555	2,322,039	1,832,901	1,948,083	2,089,317	
Total	$6,763,340	$7,163,174	$6,148,865	$6,389,365	$6,485,804	
Total Demand/Energy	$1,353,542	$1,395,392	$1,343,547	$1,418,238	$1,416,857	
Total Customer	5,409,798	5,767,782	4,805,318	4,971,127	5,068,947	
Total	$6,763,340	$7,163,174	$6,148,865	$6,389,365	$6,485,804	
Percent Demand/Energy	20.01%	19.48%	21.85%	22.20%	21.85%	
Percent Customer	79.99%	80.52%	78.15%	77.80%	78.15%	
Percent Total	100.00%	100.00%	100.00%	100.00%	100.00%	
Administrative & General Expenses						
(Classified Based on O&M Excl. Purchased Gas and A&G)						
Administrative & General						
Demand/Energy-Related	$920,394	$900,082	$846,736	$757,081	$901,861	
Customer-Related	3,679,278	3,720,462	3,028,485	2,653,195	3,225,649	3,261,414
Total A&G	$4,599,672	$4,620,544	$3,875,221	$3,410,276	$4,127,510	
Index to Adjust to 1/1/14	1.0890	1.0697	1.0583	1.0857	1.0750	
Administrative & General (Restated at 1/1/14)						
Demand/Energy-Related	$1,002,309	$962,818	$896,101	$821,963	$969,501	$930,538
Customer-Related	4,006,734	3,979,778	3,205,046	2,880,574	3,467,573	3,507,941
Total A&G	$5,009,043	$4,942,596	$4,101,147	$3,702,537	$4,437,074	$4,438,479

1/ Exhibit No. __ (TAA-3), pages 22 & 23.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

TAXES OTHER THAN INCOME TAXES

Type of Tax	Basis	2007	2008	2009	2010	2011	Average
TAXES BY TYPE							
Federal/State							
Payroll Taxes	Payroll	$455,751	$453,557	$406,772	$480,741	$428,471	445,058
Secretary of State	Revenue	327	227	178	276	286	259
Montana Consumer Counsel	Revenue	52,379	114,964	54,733	34,647	83,064	67,957
Montana PSC	Revenue	163,343	270,916	197,512	193,003	272,846	219,524
Highway Use Tax	Revenue	155	210	207	203	210	197
Delaware Franchise	Property	18,849	18,263	19,241	17,913	19,066	18,666
Tribal Tax	Revenue	4,736	5,357	5,511	5,908	6,194	5,541
Local							
Property Taxes	Property	1,737,728	2,170,886	2,244,794	2,393,648	2,497,882	2,208,988
Total Taxes Other		$2,433,268	$3,034,380	$2,928,948	$3,126,339	$3,308,019	$2,966,190
Taxes Other by Basis							
Payroll		$455,751	$453,557	$406,772	$480,741	$428,471	$445,058
Property		1,756,577	2,189,149	2,264,035	2,411,561	2,516,948	2,227,654
Revenue		220,940	391,674	258,141	234,037	362,600	293,478
Total		$2,433,268	$3,034,380	$2,928,948	$3,126,339	$3,308,019	$2,966,190
Basis for Taxes Other							
Payroll (O&M Excl. Purchased Gas) 1/		$11,363,012	$11,783,718	$10,024,086	$9,799,641	$10,613,314	$10,716,754
Property (Avg. Plant; TOC Basis) 2/		348,468,963	363,309,962	379,645,481	384,946,901	379,265,801	371,127,422
Revenue (Operating Revenue)		69,617,491	93,910,680	77,730,500	70,844,518	74,110,974	77,242,833
Taxes Other as a Percent of Basis							
Payroll		4.01%	3.85%	4.06%	4.91%	4.04%	4.15%
Property		0.50%	0.60%	0.60%	0.63%	0.66%	0.60%
Revenue		0.32%	0.42%	0.33%	0.33%	0.49%	0.38%

1/ Exhibit No. __ (TAA-3), page 25.
1/ Exhibit No. __ (TAA-3), page 24.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

CUSTOMER-RELATED CUSTOMER ACCOUNTS EXPENSE

	Customer Class					
	Total	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
Average No. of Customers	78,910	70,161	6,547	2,153	44	5
<u>Customer Accounts Expense</u>						
Weighting Factor		1.0	1.1	9.1	36.7	54.6
Weighted Customers	98,843	70,161	7,202	19,593	1,614	273
Five-Year Average (1/1/06 Dollars)						
Average Expense per Customer 1/	$29.14					
Expense Allocated on Weighted Customers	$2,299,437	$1,632,192	$167,544	$455,802	$37,547	$6,351
Annual Expense per Customer	$29.14	$23.26	$25.59	$211.71	$853.34	$1,270.20
<u>Customer Service & Informational Expenses</u>						
Weighting Factor		1.0	1.0	1.0	1.0	1.0
Weighted Customers	78,910	70,161	6,547	2,153	44	5
Five-Year Average (1/1/06 Dollars)						
Average Expense per Customer 1/	$1.05					
Expense Allocated on Weighted Customers	$82,856	$73,669	$6,874	$2,261	$46	$5
Annual Expense per Customer	$1.05	$1.05	$1.05	$1.05	$1.05	$1.00
<u>Sales Expenses</u>						
Weighting Factor		1.0	1.1	9.1	36.7	54.6
Weighted Customers	98,843	70,161	7,202	19,593	1,614	273
Five-Year Average (1/1/06 Dollars)						
Average Expense per Customer 1/	$2.50					
Expense Allocated on Weighted Customers	$197,275	$140,030	$14,374	$39,105	$3,221	$545
Annual Expense per Customer	$2.50	$2.00	$2.20	$18.16	$73.20	$109.00
Total Customer-Related Expenses	$32.69	$26.31	$28.84	$230.92	$927.59	$1,380.20

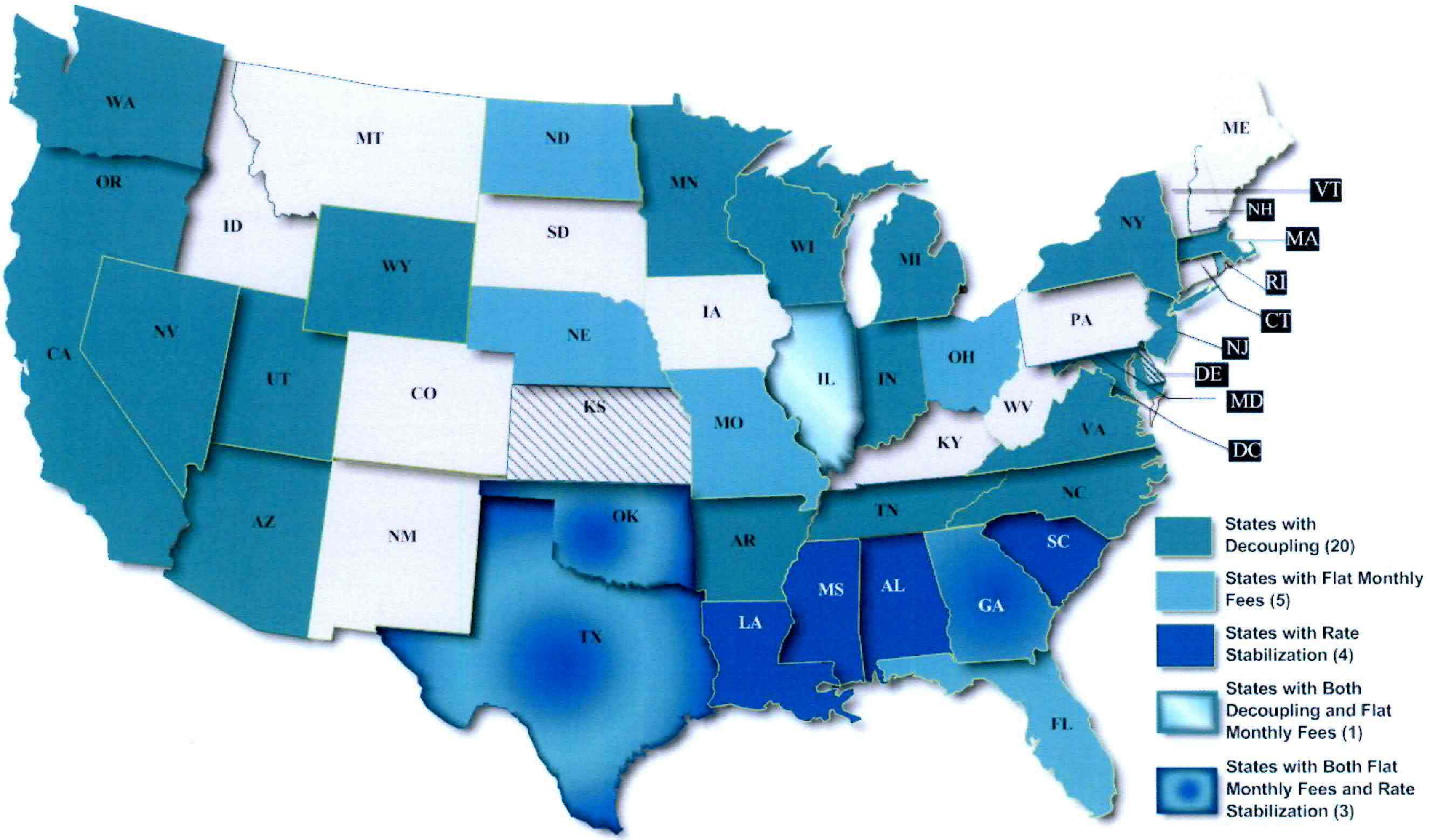
1/ Exhibit No.___(TAA-3) page 28.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

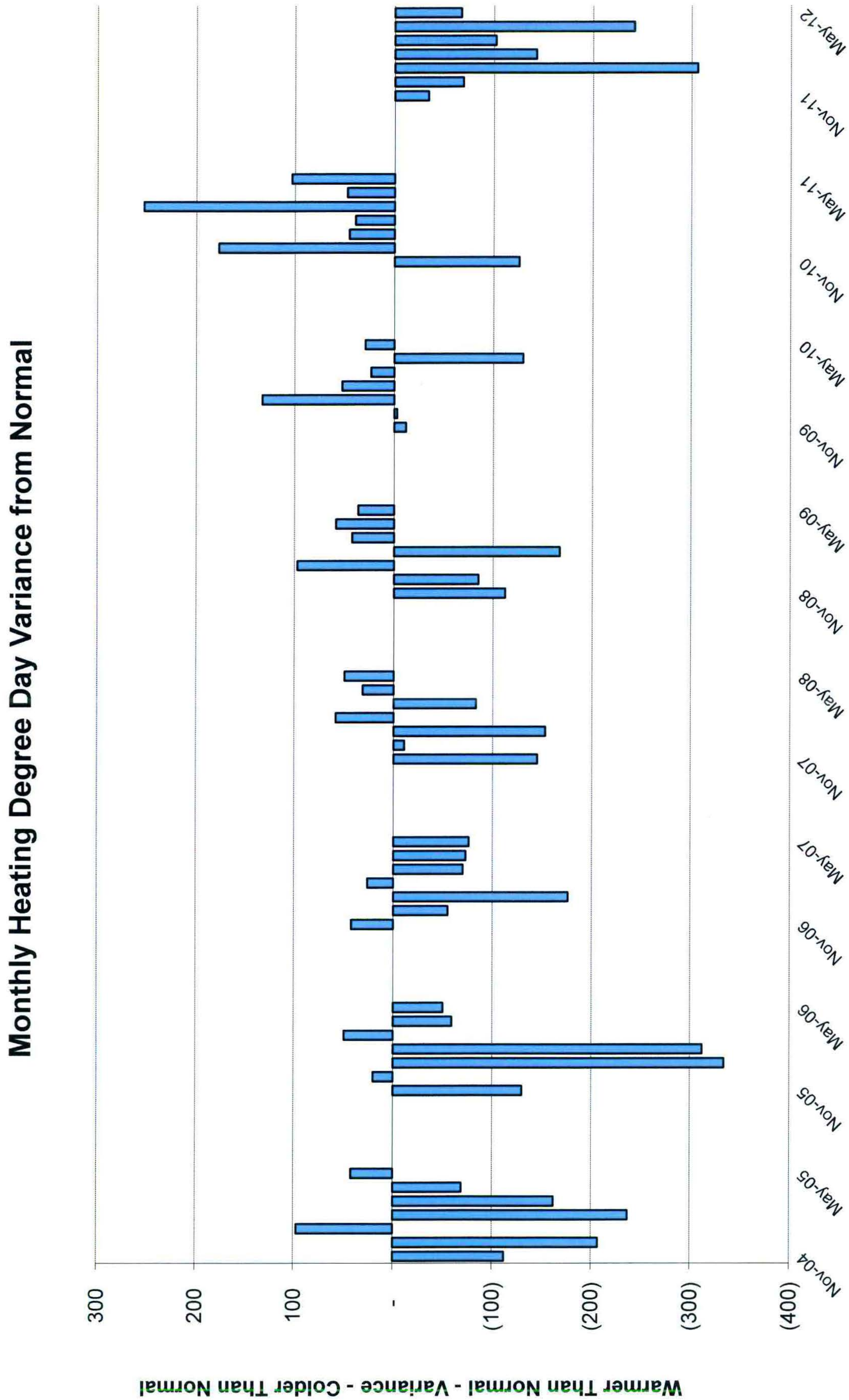
CUSTOMER-RELATED CUSTOMER ACCOUNTS EXPENSE

	2007	2008	2009	2010	2011	Average
Average No. of Customers	75,494	76,454	77,247	77,925	78,910	77,206
Customer Accounts	$2,272,555	$2,322,039	$2,071,005	$1,832,901	$1,948,083	$2,089,317
Per Customer ($/customer/year)	30.10	30.37	26.81	23.52	24.69	
Adjusted to 1/1/14	$32.78	$32.49	$28.37	$25.54	$26.54	$29.14
Customer Service & Informational	$62,266	$100,475	$71,148	$55,796	$89,100	$75,757
Per Customer ($/customer/year)	0.82	1.31	0.92	0.72	1.13	
Adjusted to 1/1/14	$0.89	$1.40	$0.97	$0.78	$1.21	$1.05
Sales Expenses	$233,097	$235,578	$168,744	$137,023	$119,573	$178,803
Per Customer ($/customer/year)	3.09	3.08	2.18	1.76	1.52	
Adjusted to 1/1/14	$3.37	$3.29	$2.31	$1.91	$1.63	$2.50

States with Non-Volumetric Rate Designs (Decoupling, Flat Monthly Fee, Rate Stabilization) 33 Approved, 2 Pending As of March 2012



AGA American Gas Association


Monthly Heating Degree Day Variance from Normal
Warmer Than Normal - Variance - Colder Than Normal
300
200
100
-
(100)
(200)
(300)
(400)
Nov-04
May-05
Nov-05
May-06
Nov-06
May-07
Nov-07
May-08
Nov-08
May-09
Nov-09
May-10
Nov-10
May-11
Nov-11
May-12

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
DDSM BILL COMPARISON
RESIDENTIAL GAS SERVICE

		Normal Weather		**20% Warmer Weather**		**20% Colder Weather**	
Bill Component	Unit Charge 1/	Dk	Amount	Dk	Amount	Dk	Amount
Basic Service Charge	$10.64		$10.64		$10.64		$10.64
Cost of Gas	3.857	13.9	53.61	11.4	43.97	16.4	63.25
Distribution Delivery Charge	0.998	13.9	13.87	11.4	11.38	16.4	16.37
DDSM Adjustment 2/	0.998	0.0	0.00	2.5	2.50	(2.5)	(2.50)
Total Monthly Bill			$78.12		$68.49		$87.76
Change in Bill from Normal Weather					($9.63)		$9.64

1/ Rule 38.5.177, Statement M, Page 3.
2/ DDSM Calculation & Assumptions:

Normal Degree Days	1082	Normal Degree Days	1082
- Actual Degree Days	866	- Actual Degree Days	1298
	216		(216)
/ Actual Degree Days	866	/ Actual Degree Days	1298
Degree Day Factor	0.2494	Degree Day Factor	(0.1664)
# of Days	28	# of Days	28
* Daily Base Use	0.04849	* Daily Base Use	0.04849
Monthly Base Use	1.4	Monthly Base Use	1.4
Monthly Actual Use	11.4	Monthly Actual Use	16.4
- Base Use	1.4	- Base Use	1.4
Heating Use	10	Heating Use	15
* Degree Day Factor	0.2494	* Degree Day Factor	(0.1664)
DDSM Dk	2.5	DDSM Dk	(2.5)

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Total Company	Montana	Other	Reference
Operating Revenues				
Sales	$242,315,494	$72,489,259	$169,826,235	Rule 38.5.164
Transportation	3,731,261	1,252,889	2,478,372	Rule 38.5.164
Other	1,630,614	368,826	1,261,788	Rule 38.5.164
Total Revenues	247,677,369	74,110,974	173,566,395	
Operating Expenses				
Operation and Maintenance				
Cost of Gas	179,121,296	52,735,031	126,386,265	Rule 38.5.157
Other O&M	38,564,254	10,869,311	27,694,943	Rule 38.5.157
Total O&M	217,685,550	63,604,342	154,081,208	
Depreciation	9,814,146	3,011,298	6,802,848	Rule 38.5.165
Taxes Other Than Income	6,138,074	3,308,019	2,830,055	Rule 38.5.173
Current Income Taxes	(11,756,557)	(2,930,186)	(8,826,371)	Rule 38.5.169
Deferred Income Taxes	13,390,065	3,489,201	9,900,864	Rule 38.5.169
Total Expenses	235,271,278	70,482,674	164,788,604	
Operating Income	$12,406,091	$3,628,300	$8,777,791	
Rate Base	$134,025,220	$43,247,498	$90,777,722	
Rate of Return	9.257%	8.390%	9.670%	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Total Company	Montana	Other	Reference
Gas Plant in Service	$322,437,954	$94,105,839	$228,332,115	Rule 38.5.123
Accumulated Reserve for Depreciation	174,081,879	51,259,183	122,822,696	Rule 38.5.133
Net Gas Plant in Service	148,356,075	42,846,656	105,509,419	
CWIP in Service Pending Reclassification	2,807,343	500,474	2,306,869	Rule 38.5.123
Total Gas Plant in Service	151,163,418	43,347,130	107,816,288	
Additions				
Materials and Supplies	2,005,951	533,337	1,472,614	Rule 38.5.141
Fuel Stocks	22,844	0	22,844	Rule 38.5.141
Gas in Underground Storage	7,134,766	7,134,766	0	Rule 38.5.141
Prepayments	1,237,614	1,175,889	61,725	Rule 38.5.141
Loss on Debt	1,956,550	584,820	1,371,730	Rule 38.5.141
Other	152,688	128,892	23,796	Rule 38.5.141
Total Additions	12,510,413	9,557,704	2,952,709	
Total Before Deductions	$163,673,831	$52,904,834	$110,768,997	
Deductions				
Accumulated Deferred Income Taxes	24,948,195	8,925,996	16,022,199	Rule 38.5.169
Accumulated Investment Tax Credits	11,925	4,084	7,841	Rule 38.5.169
Customer Advances	4,688,491	727,256	3,961,235	Rule 38.5.141
Total Deductions	29,648,611	9,657,336	19,991,275	
Total Rate Base	$134,025,220	$43,247,498	$90,777,722	

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - MONTANA

	Adjustment No.	Pro Forma Adjustment	Reference
Revenue			
Current rates	1	($13,609,329)	Rule 38.5.164 Statement H, page 3
Normal Weather	2	(1,467,031)	Rule 38.5.164 Statement H, page 4
Annualized volumes	3	257,226	Rule 38.5.164 Statement H, page 5
Other Revenue	4	47,286	Rule 38.5.164 Statement H, page 6
Total adjustments to Revenue		($14,771,848)	
Expenses			
Cost of Gas	5	($13,880,459)	Rule 38.5.157 Statement G, page 3
Other O&M			
Labor	6	$269,722	Rule 38.5.157 Statement G, page 4
Benefits	7	(75,501)	Rule 38.5.157 Statement G, page 5
Vehicles & Work Equipment	8	(6,716)	Rule 38.5.157 Statement G, page 6
Company Consumption	9	(8,120)	Rule 38.5.157 Statement G, page 7
Uncollectible Accounts	10	(14,963)	Rule 38.5.157 Statement G, page 8
Advertising	11	(31,656)	Rule 38.5.157 Statement G, page 9
Insurance	12	13,839	Rule 38.5.157 Statement G, page 10
Industry Dues	13	(7,138)	Rule 38.5.157 Statement G, page 11
Regulatory Commission Expense	14	108,300	Rule 38.5.157 Statement G, page 12
Total adjustments to Other O&M		247,767	
Depreciation Expense	15	1,412,304	Rule 38.5.165 Statement I, page 1
Taxes Other than Income			
Ad Valorem	16	114,387	Rule 38.5.174 Statement K, page 1
Payroll Taxes	17	20,322	Rule 38.5.174 Statement K, page 3
MCC and PSC Taxes	18	(167,229)	Rule 38.5.174 Statement K, page 4
Total adj. to Taxes Other than Income		(32,520)	
Current Income Taxes			
Interest Annualization	19	(51,878)	Rule 38.5.169 Statement J, page 8
Tax Depreciation on Plant Additions	20	2,817,177	Rule 38.5.169 Statement J, page 9
Other Tax Deductions	21	(400,022)	Rule 38.5.169 Statement J, page 10
Income Taxes on Pro Forma Adj.	22	(1,923,771)	Rule 38.5.169 Statement J, page 11
Elimination of Closing/Filing and Prior Period	23	1,560,882	Rule 38.5.169 Statement J, page 12
Total adj. to Current Income Taxes		(362,889)	
Deferred Income Taxes			
Plant Additions	20	1,109,616	Rule 38.5.169 Statement J, page 9
Elimination of Closing/Filing and Prior Period	23	(1,302,970)	Rule 38.5.169 Statement J, page 12
Other Tax Deductions	21	38,579	Rule 38.5.169 Statement J, page 10
Total adj. to Deferred Income Taxes		(154,775)	
Total Expenses		(12,770,572)	
Net Adjustments to Operating Income		($2,001,276)	

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
SUMMARY OF PRO FORMA RATE BASE ADJUSTMENTS

Plant	Adjustment	Amount	Reference	
Plant Additions	A	$6,357,622	Rule 38.5.123	Statement C Page 2
Accumulated Reserve				
Plant Additions	B	3,202,646	Rule 38.5.133	Statement D Page 2
Adjustments to Net Plant		3,154,976		
Additions:				
Materials and Supplies	C	99,695	Rule 38.5.143	Statement E Page 1
Gas in Underground Storage	D	(855,502)	Rule 38.5.143	Statement E Page 2
Prepaid Insurance	E	93,808	Rule 38.5.143	Statement E Page 3
Prepaid Demand and Commodity	F	(642,915)	Rule 38.5.143	Statement E Page 4
Unamortized Loss on Debt	G	(53,806)	Rule 38.5.143	Statement E Page 5
Provision for Pensions & Benefits	H	1,268,837	Rule 38.5.143	Statement E Page 6
Provision for Injuries & Damages	I	(109,736)	Rule 38.5.143	Statement E Page 7
Deferred FAS 106 Costs	J	273,775	Rule 38.5.143	Statement E Page 8
Total Additions		74,156		
Deductions:				
Accumulated Def. Inc. Tax				
Plant Additions	K	1,887,637	Rule 38.5.169	Statement J Page 17
Normalization	L	(25,349)	Rule 38.5.169	Statement J Page 17
Deferred FAS 106 Costs	J	105,855	Rule 38.5.169	Statement J Page 17
Unamortized Loss on Debt	G	(31,526)	Rule 38.5.169	Statement J Page 17
Pensions & Benefits	H	846,179	Rule 38.5.169	Statement J Page 17
Injuries and Damages	I	(41,583)	Rule 38.5.169	Statement J Page 17
Investment Tax Credits	M	(3,488)	Rule 38.5.169	Statement J Page 17
Customer Advances for Construction	N	(20,926)	Rule 38.5.143	Statement E Page 9
Total Deductions		2,716,799		
Total Pro Forma Adjustments		$512,333		

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA INCOME STATEMENT
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Per Books	Pro Forma Adjustments	Total Adjusted Amount
Operating Revenues			
Sales	$72,489,259	($14,697,778)	$57,791,481
Transportation	1,252,889	(121,356)	1,131,533
Other	368,826	47,286	416,112
Total Revenues	74,110,974	(14,771,848)	59,339,126
Operating Expenses			
Operation and Maintenance			
Cost of Gas	52,735,031	(13,880,459)	38,854,572
Other O&M	10,869,311	247,767	11,117,078
Total O&M	63,604,342	(13,632,692)	49,971,650
Depreciation	3,011,298	1,412,304	4,423,602
Taxes Other Than Income	3,308,019	(32,520)	3,275,499
Current Income Taxes	(2,930,186)	(362,889)	(3,293,075)
Deferred Income Taxes	3,489,201	(154,775)	3,334,426
Total Expenses	70,482,674	(12,770,572)	57,712,102
Operating Income	$3,628,300	($2,001,276)	$1,627,024
Rate Base	$43,247,498	$512,333	$43,759,831
Rate of Return	8.390%		3.718%

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA

	Average Balance @ 12/31/11	Pro Forma Adjustments	Pro Forma
Gas Plant in Service	$94,105,839	$6,357,622	$100,463,461
Accumulated Reserve for Depreciation	51,259,183	3,202,646	54,461,829
Net Gas Plant in Service	42,846,656	3,154,976	46,001,632
CWIP in Service Pending Reclassification	500,474		500,474
Total Gas Plant in Service	43,347,130	3,154,976	46,502,106
Additions			
Materials and Supplies	533,337	99,695	633,032
Gas in Underground Storage	7,134,766	(855,502)	6,279,264
Prepayments	1,175,889	(549,107)	626,782
Unamortized Gain (Loss) on Debt	584,820	(53,806)	531,014
Provision for Pensions & Benefits		1,268,837	1,268,837
Provision for Injuries & Damages		(109,736)	(109,736)
Deferred FAS 106 Costs	128,892	273,775	402,667
Total Additions	9,557,704	74,156	9,631,860
Total Before Deductions	$52,904,834	$3,229,132	$56,133,966
Deductions			
Accumulated Deferred Income Taxes	8,925,996	2,741,213	11,667,209
Accumulated Investment Tax Credits	4,084	(3,488)	596
Customer Advances	727,256	(20,926)	706,330
Total Deductions	9,657,336	2,716,799	12,374,135
Total Rate Base	$43,247,498	$512,333	$43,759,831

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS
GAS UTILITY - MONTANA
MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$57,791,481	**$3,455,478**		$61,246,959
Transportation	1,131,533			1,131,533
Other	416,112			416,112
Total Revenues	59,339,126	3,455,478		62,794,604
Operating Expenses				
Operation and Maintenance				
Cost of Gas	38,854,572			38,854,572
Other O&M	11,117,078			11,117,078
Total O&M	49,971,650			49,971,650
Depreciation	4,423,602			4,423,602
Taxes Other Than Income	3,275,499	11,058	2/	3,286,557
Current Income Taxes	(3,293,075)	1,356,672	2/	(1,936,403)
Deferred Income Taxes	3,334,426			3,334,426
Total Expenses	57,712,102	1,367,730		59,079,832
Operating Income	$1,627,024	$2,087,748		$3,714,772
Rate Base	$43,759,831			$43,759,831
Rate of Return	**3.718%**			**8.489%**

1/ See Rule 38.5.175, page 6.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of .12% and PSC tax of .20%.

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MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND DECEMBER 31, 2011

	2010	2011
Assets and Other Debits		
Utility Plant	$1,343,386,275	$1,393,817,730
Construction Work in Progress	40,572,541	54,926,027
Less Acc. Provision for Depreciation and Amortization	673,742,452	699,092,675
Net Utility Plant	710,216,364	749,651,082
Gas Stored Underground - Noncurrent	3,560,347	3,551,913
Other Property and Investments		
Nonutility Property	4,168,474	4,345,368
(Less) Accum. Prov. for Depr. And Amort.	1,311,967	1,460,122
Investment in Subsidiary Companies	2,336,133,125	2,402,890,906
Other investments	48,037,819	47,834,766
Net Other Property and Investments	2,387,027,451	2,453,610,918
Current and Accrued Assets		
Cash	6,238,148	6,845,910
Special Deposits	1,200	1,200
Working Fund	36,865	54,764
Temporary Cash Investments	0	0
Customer Accounts Receivable	29,395,116	26,202,128
Other Accounts Receivable	4,363,648	2,785,945
(Less) Accum.Prov. For Uncollectible Acct. - Credit	231,003	237,599
Notes Receivable from Assoc. Companies	0	0
Accounts Receivable from Assoc.Companies	27,836,855	28,733,840
Fuel Stock	5,029,867	5,921,977
Plant Materials and Operating Supplies	10,139,125	14,611,115
Merchandise	876,220	915,028
Stores Expense Undistributed	(639)	0
Gas Stored Underground - Current	18,538,439	21,147,886
Prepayments	4,438,120	4,929,924
Accured Utility Revenues	37,326,027	31,824,896
Miscellaneous Current and Accrued Assets	0	0
Total Current and Accrued Assets	143,987,988	143,737,014
Deferred Debits		
Unamortized Debt Expenses	1,126,622	1,046,963
Unrecovered Plant and Regulatory Study Costs	7,564,400	8,953,457
Other Regulatory Assets	86,467,267	123,145,685
Prelim. Survey and Investigation Charges (Electric)	321,479	1,311,495
Prelim. Survey and Investigation Charges (Natural Gas)	0	0
Clearing Accounts	109,955	141,904
Miscellaneous Deferred Debits	25,010,265	28,845,868
Unamortized Loss on Reaquired Debt	9,565,612	8,846,102
Accumulated Deferred Income Taxes	59,053,683	65,712,445
Unrecovered Purchased Gas Costs	2,110,509	2,622,263
Total Deferred Debits	191,329,792	240,626,182
Total Assets and Other Debits	$3,436,121,942	$3,591,177,109

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND
DECEMBER 31, 2011

	2010	2011
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$188,901,379	$189,332,485
Preferred Stock Issued	15,000,000	15,000,000
Premium on Capital Stock	1,030,458,868	1,039,849,252
(Less) Capital Stock Expense	4,110,305	4,110,305
Retained Earnings	492,507,658	505,281,931
Unappropriated Undistributed Sub Earnings	1,004,931,088	1,080,840,155
(Less) Reacquired Capital Stock	3,625,813	3,625,813
Accumulated Other Comprehensive Income	(31,261,155)	(47,000,996)
Total Proprietary Capital	2,692,801,720	2,775,566,709
Long-Term Debt		
Bonds	280,000,000	280,000,000
Other Long-Term Debt	995,927	888,853
(Less) Unamortized Discount on Long-Term Debt-Debit	0	0
Total Long-Term Debt	280,995,927	280,888,853
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	936,497	568,573
Accumulated Provision for Pensions and Benefits	54,957,735	73,404,001
Accumulated Provision for Rate Refunds	0	640,000
Asset Retirement Obligations	6,314,471	6,645,275
Total Other Noncurrent Liabilities	62,208,703	81,257,849
Current and Accrued Liabilities		
Notes Payable	20,000,000	0
Accounts Payable	34,271,793	36,325,957
Accounts Payable to Associated Companies	9,445,305	4,867,683
Customer Deposits	2,019,003	1,926,012
Taxes Accrued	5,133,221	18,303,603
Interest Accrued	4,928,786	4,928,205
Dividends Declared	30,772,550	31,794,172
Tax Collections Payable	1,963,158	1,660,047
Miscellaneous Current and Accrued Liabilities	23,267,497	21,988,799
Total Current and Accrued Assets	131,801,313	121,794,478
Deferred Credits		
Customer Advances for Construction	7,133,209	8,440,494
Accumulated Deferred Investment Tax Credit	797,879	871,217
Other Deferred Credits	88,934,756	108,892,007
Other Regulatory Liabilities	8,088,640	10,003,775
Accumulated Deferred Income Taxes	163,359,795	203,461,727
Total Deferred Credits	268,314,279	331,669,220
Total Liabilities and Equity	$3,436,121,942	$3,591,177,109

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2011 AND
JUNE 30, 2012

	2011	2012
Assets and Other Debits		
Utility Plant	$1,356,122,197	$1,412,357,266
Construction Work in Progress	46,776,499	100,110,499
Less Acc. Provision for Depreciation and Amortization	688,313,316	713,894,307
Net Utility Plant	714,585,380	798,573,458
Gas Stored Underground - Noncurrent	2,765,041	3,551,913
Other Property and Investments		
Nonutility Property	4,212,161	4,468,867
(Less) Accum. Prov. for Depr. And Amort.	1,377,001	1,548,142
Investment in Subsidiary Companies	2,357,546,703	2,442,402,802
Other investments	49,466,444	49,775,303
Net Other Property and Investments	2,409,848,307	2,495,098,830
Current and Accrued Assets		
Cash	40,181,141	3,243,811
Special Deposits	1,200	251,415
Working Fund	35,975	50,975
Temporary Cash Investments	0	0
Customer Accounts Receivable	25,871,417	17,000,792
Other Accounts Receivable	2,498,821	1,832,911
(Less) Accum.Prov. For Uncollectible Acct. - Credit	346,710	221,530
Notes Receivable from Assoc. Companies	0	0
Accounts Receivable from Assoc.Companies	27,280,773	27,846,311
Fuel Stock	3,908,960	5,109,064
Plant Materials and Operating Supplies	11,547,963	19,871,046
Merchandise	873,215	905,451
Stores Expense Undistributed	36,506	58,175
Gas Stored Underground - Current	2,480,991	13,102,007
Prepayments	2,390,075	3,105,790
Accured Utility Revenues	10,496,186	12,641,005
Miscellaneous Current and Accrued Assets	0	2,495,484
Total Current and Accrued Assets	127,256,513	107,292,707
Deferred Debits		
Unamortized Debt Expenses	1,098,609	1,000,051
Unrecovered Plant and Regulatory Study Costs	10,659,285	7,393,069
Other Regulatory Assets	80,603,619	119,405,158
Prelim. Survey and Investigation Charges (Electric)	645,080	472,602
Prelim. Survey and Investigation Charges (Natural Gas)	0	0
Clearing Accounts	1,354,878	883,754
Miscellaneous Deferred Debits	25,140,198	28,571,397
Unamortized Loss on Reaquired Debt	9,205,857	8,486,346
Accumulated Deferred Income Taxes	57,414,356	65,093,706
Unrecovered Purchased Gas Costs	598,173	(2,732,787)
Total Deferred Debits	186,720,055	228,573,296
Total Assets and Other Debits	$3,441,175,296	$3,633,090,204

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2011 AND
JUNE 30, 2012

	2011	2012
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$189,332,485	$189,369,450
Preferred Stock Issued	15,000,000	15,000,000
Premium on Capital Stock	1,037,476,242	1,041,044,905
(Less) Capital Stock Expense	4,110,305	4,110,305
Retained Earnings	500,449,310	510,047,453
Unappropriated Undistributed Sub Earnings	1,023,095,832	1,102,120,464
(Less) Reacquired Capital Stock	3,625,813	3,625,813
Accumulated Other Comprehensive Income	(32,267,799)	(29,574,553)
Total Proprietary Capital	2,725,349,952	2,820,271,601
Long-Term Debt		
Bonds	280,000,000	280,000,000
Other Long-Term Debt	992,403	7,885,162
(Less) Unamortized Discount on Long-Term Debt-Debit	0	0
Total Long-Term Debt	280,992,403	287,885,162
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	747,153	526,179
Accumulated Provision for Pensions and Benefits	55,420,379	74,591,673
Accumulated Provision for Rate Refunds	0	1,280,682
Asset Retirement Obligations	6,476,302	6,626,786
Total Other Noncurrent Liabilities	62,643,834	83,025,320
Current and Accrued Liabilities		
Notes Payable	0	0
Accounts Payable	22,888,737	26,285,558
Accounts Payable to Associated Companies	6,332,840	6,508,399
Customer Deposits	1,923,378	1,920,511
Taxes Accrued	1,448,797	14,502,978
Interest Accrued	4,959,146	4,951,588
Dividends Declared	30,850,204	31,800,364
Tax Collections Payable	935,297	1,108,838
Miscellaneous Current and Accrued Liabilities	23,368,491	20,853,771
Total Current and Accrued Assets	92,706,890	107,932,007
Deferred Credits		
Customer Advances for Construction	6,908,677	10,163,593
Accumulated Deferred Investment Tax Credit	763,013	843,563
Other Deferred Credits	82,868,858	101,008,872
Other Regulatory Liabilities	10,883,825	10,173,075
Accumulated Deferred Income Taxes	178,057,844	211,787,011
Total Deferred Credits	279,482,217	333,976,114
Total Liabilities and Equity	$3,441,175,296	$3,633,090,204

NOTES TO THE FINANCIAL STATEMENTS

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $1.2 billion; current and accrued assets would increase by $1.1 billion; deferred debits would increase by $726.4 million; long-term debt would increase by $1.0 billion; other noncurrent liabilities and current and accrued liabilities would increase by $695.7 million; deferred credits would increase by $1.3 billion as of December 31, 2011. Furthermore, operating revenues would increase by $3.5 billion and operating expenses, excluding income taxes, would increase by $3.2 billion for the twelve months ended December 31, 2011. In addition, net cash provided by operating activities would increase by $407.3 million; net cash used in investing activities would increase by $384.1 million; net cash used in financing activities would increase by $82.8 million; the effect of exchange rate changes on cash would decrease by $214,000; and the net change in cash and cash equivalents would be a decrease of $59.9 million for the twelve months ended December 31, 2011. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Company's notes to the financial statements are presented consolidated with its subsidiary investments and prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2011	2010
	(In thousands)	
Aggregates held for resale	$ **78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182
Other	**32,998**	25,706
Total	$ **274,205**	$ 252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments
The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance investment contract, auction rate securities, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair

value option for its auction rate securities, mortgage-backed securities and U.S. Treasury securities. For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Property, plant and equipment at December 31 was as follows:

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 546,783	$ 538,071	47
Distribution	255,232	243,205	36
Transmission	179,580	161,972	44
Other	86,929	83,786	13
Natural gas distribution:			
Distribution	1,257,360	1,223,239	38
Other	311,506	285,606	23
Pipeline and energy services:			
Transmission	386,227	357,395	52
Gathering	42,378	41,931	19
Storage	41,908	33,967	51
Other	36,179	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	198,864	203,064	17
Other	13,735	13,512	10
Exploration and production:			
Natural gas and oil properties	2,577,576	2,320,967	*
Other	37,570	35,971	9
Construction materials and contracting:			
Land	126,790	124,018	—
Buildings and improvements	67,627	65,003	20
Machinery, vehicles and equipment	902,136	899,365	12
Construction in progress	8,085	4,879	—
Aggregate reserves	395,214	393,110	**
Construction services:			
Land	4,706	4,526	—
Buildings and improvements	15,001	14,101	22
Machinery, vehicles and equipment	95,891	94,252	7
Other	9,198	10,061	4
Other:			
Land	2,837	2,837	—
Other	46,910	29,727	24
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	
Net property, plant and equipment	$ 4,285,014	$ 4,115,180	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.*

** *Depleted on the units-of-production method.*

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 5.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

Due to low natural gas and oil prices that existed at March 31, 2009, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the year ended December 31, 2009.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of $107.9 million ($66.9 million after tax) at March 31, 2009, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

At December 31, 2011, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2011, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
			(In thousands)		
Acquisition	$ 185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$ 232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, respectively.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's swap and collar agreements are reflected at fair value. For more information, see Note 8.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax positions in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009*
	(In thousands)		
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

** Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.*

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the acquisition method of accounting; natural gas and oil reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	**2011**	2010	2009
	(In thousands)		
Interest, net of amount capitalized	$ **78,133**	$ 80,962	$ 81,267
Income taxes paid (refunded), net	$ **(12,287)**	$ 46,892	$ 39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards

Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive loss resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
Other comprehensive loss:			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	$ 7,900	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	—	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	7,900	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	(22,427)	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	(1,295)	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	82	—	—
Total other comprehensive loss	$ (15,740)	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Note 2 - Acquisitions

In 2011, a purchase price adjustment, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

In 2009, the Company acquired a pipeline and energy services business in Montana which was not material. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company's common stock and cash, was $22.0 million.

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 - Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2011 and 2010, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of December 31, 2011*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

** *Includes a purchase price adjustment that was not material related to an acquisition in a prior period.*

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010*	Goodwill Acquired During the Year**	Balance as of December 31, 2010*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

** *Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

Other amortizable intangible assets at December 31 were as follows:

	2011	2010
	(In thousands)	
Customer relationships	$ 21,702	$ 24,942
Accumulated amortization	(10,392)	(11,625)
	11,310	13,317
Noncompete agreements	7,685	9,405
Accumulated amortization	(5,371)	(6,425)
	2,314	2,980
Other	11,442	13,217
Accumulated amortization	(4,223)	(4,243)
	7,219	8,974
Total	$ 20,843	$ 25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Note 6 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period*	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	171,492	103,818
Deferred income taxes	**	119,189	114,427
Taxes recoverable from customers (a)	—	12,433	11,961
Plant costs (a)	Over plant lives	10,256	9,964
Long-term debt refinancing costs (a)	Up to 27 years	10,112	11,101
Costs related to identifying generation development (a)	Up to 15 years	9,817	13,777
Natural gas supply derivatives (b)	Up to 1 year	437	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	2,622	6,609
Other (a) (b)	Largely within 1 year	22,651	35,225
Total regulatory assets		359,009	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		289,972	276,652
Deferred income taxes**		84,963	64,017
Natural gas costs refundable through rate adjustments (d)		45,064	36,996
Taxes refundable to customers (c)		31,837	19,352
Other (c) (d)		8,393	16,080
Total regulatory liabilities		460,229	413,097
Net regulatory position		(101,220)	(96,856)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*

** *Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.*

(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.

(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.

(c) Included in other liabilities on the Consolidated Balance Sheets.

(d) Included in other accrued liabilities on the Consolidated Balance Sheets.

(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain

At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000.

The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $437,000.

Fidelity

At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $18.4 million.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 27,687	$ 15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$ 30,455	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 12,727	$ 15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$ 18,863	$ 30,911

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8

million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Signficant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* *The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541
Auction rate securities	—	11,400	—	11,400
Commodity derivative instruments - current	—	15,123	—	15,123
Commodity derivative instruments - noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$ —	$ 236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments - current	$ —	$ 24,428	$ —	$ 24,428
Commodity derivative instruments - noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$ —	$ 30,911	$ —	$ 30,911

* *The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only, and was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2011. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2011	Amount Outstanding at December 31, 2010	Letters of Credit at December 31, 2011	Expiration Date
			(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 100.0	$ — (h)	$ 20.0 (b)	$ —	5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ —	$ —	$ 1.9 (d)	12/28/12(e)
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (f)	$ 8.1	$ 20.2	$ —	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$ 400.0	$ — (h)	$ — (h)	$ 21.6 (d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program that was classified as short-term borrowings because the revolving credit agreement expired within one year.

(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.

(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

(e) Provisions allow for an extension of up to two years upon consent of the banks.

(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.

(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.

(h) Amount outstanding under commercial paper program.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Cascade Natural Gas Corporation Any borrowings under the $50 million revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Long-term debt

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

Intermountain Gas Company The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in 2010; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent. The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	**$ 1,287,576**	$ 1,358,848
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	**81,000**	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	**$ 1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate \$139.3 million in 2012; \$267.3 million in 2013; \$9.3 million in 2014; \$266.4 million in 2015; \$288.4 million in 2016 and \$454.0 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

	2011	2010
	(In thousands)	
Balance at beginning of year	$ 95,970	$ 76,359
Liabilities incurred	3,870	8,608
Liabilities acquired	—	5,272
Liabilities settled	(10,418)	(10,740)
Accretion expense	4,466	3,588
Revisions in estimates	3,921	12,621
Other	342	262
Balance at end of year	$ 98,151	$ 95,970

The Company believes that any expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2011	2010
	(Dollars in thousands)	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	$ 10,000	$ 10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$ 15,000	$ 15,000

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 12 - Common Stock

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$ 13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$ 13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

	2011	2010	2009
Grant-date fair value	**$ 19.99**	$ 17.40	$ 20.39
Blended volatility range	**23.20% - 32.18%**	25.69% - 35.36%	40.40% - 50.98%
Risk-free interest rate range	**.09% - 1.34%**	.13% - 1.45%	.30% - 1.36%
Discounted dividends per share	**$ 1.23**	$ 1.04	$ 1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$ 22.19
Granted	278,252	19.99
Vested	—	—
Forfeited	(185,783)	30.55
Nonvested at end of period	762,154	$ 19.35

Note 14 - Income Taxes

The components of income (loss) before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
United States	**$ 333,486**	$ 336,450	$ (227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$ (219,366)

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows:

	2011	2010	2009
	(In thousands)		
Current:			
Federal	$ (7,188)	$ 37,014	$ 64,389
State	778	10,589	8,284
Foreign	127	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Total income tax expense (benefit)	$ 110,274	$ 122,530	$ (96,092)

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 119,189	$ 114,427
Accrued pension costs	95,260	82,085
Asset retirement obligations	26,380	24,391
Legal and environmental contingencies	21,788	13,622
Compensation-related	16,241	17,261
Other	41,055	40,307
Total deferred tax assets	319,913	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	715,482	679,809
Basis differences on natural gas and oil producing properties	210,146	152,455
Regulatory matters	84,963	64,017
Intangible asset amortization	14,307	14,843
Other	23,774	20,348
Total deferred tax liabilities	1,048,672	931,472
Net deferred income tax liability	$ (728,759)	$ (639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

	2011
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 89,380
Deferred taxes associated with other comprehensive loss	9,678
Deferred taxes associated with discontinued operations	8,090
Other	11,777
Deferred income tax expense for the period	$ 118,925

Total income tax expense (benefit) differs from the amount computed by applying the statutory federal income tax rate to income (loss) before taxes. The reasons for this difference were as follows:

Years ended December 31,	2011		2010		2009	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 117,679	35.0	$ 128,293	35.0	$ (76,778)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	10,653	3.2	10,210	2.8	(7,280)	3.3
Resolution of tax matters and uncertain tax positions	(3,906)	(1.2)	667	.2	881	(.4)
Federal renewable energy credit	(3,485)	(1.0)	(2,185)	(.6)	(1,452)	.7
Depletion allowance	(3,266)	(1.0)	(2,810)	(.8)	(2,320)	1.0
Deductible K-Plan dividends	(2,282)	(.7)	(2,309)	(.6)	(2,369)	1.1
Foreign operations	(391)	(.1)	(588)	(.2)	(1,148)	.5
Domestic production activities deduction	—	—	—	—	(856)	.4
Other	(4,728)	(1.4)	(8,748)	(2.4)	(4,770)	2.2
Total income tax expense (benefit)	$ 110,274	32.8	$ 122,530	33.4	$ (96,092)	43.8

The income tax benefit in 2009 resulted largely from the Company's write-down of natural gas and oil properties, as discussed in Note 1.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2011	2010	2009
	(In thousands)		
Balance at beginning of year	$ 9,378	$ 6,148	$ 5,586
Additions for tax positions of prior years	4,172	3,230	562
Settlements	(2,344)	—	—
Balance at end of year	$ 11,206	$ 9,378	$ 6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, respectively, for the payment of interest.

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in ECTE.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in ECTE.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	$ 225,468	$ 211,544	$ 196,171
Natural gas distribution	907,400	892,708	1,072,776
Pipeline and energy services	210,846	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	359,873	318,570	338,425
Construction materials and contracting	1,509,538	1,445,148	1,515,122
Construction services	834,918	786,802	818,685
Other	2,449	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	$ 4,050,492	$ 3,909,695	$ 4,176,501
Intersegment operating revenues:			
Electric	$ —	$ —	$ —
Natural gas distribution	—	—	—
Pipeline and energy services	67,497	75,033	72,505
Exploration and production	93,713	115,784	101,230
Construction materials and contracting	472	—	—
Construction services	19,471	2,298	379
Other	8,997	7,580	9,487
Intersegment eliminations	(190,150)	(200,695)	(183,601)
Total intersegment operating revenues	$ —	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ 32,177	$ 27,274	$ 24,637
Natural gas distribution	44,641	43,044	42,723
Pipeline and energy services	25,502	26,001	25,581
Exploration and production	142,645	130,455	129,922
Construction materials and contracting	85,459	88,331	93,615
Construction services	11,399	12,147	12,760
Other	1,572	1,591	1,304
Total depreciation, depletion and amortization	$ 343,395	$ 328,843	$ 330,542

	2011	2010	2009
		(In thousands)	
Interest expense:			
Electric	$ 13,745	$ 12,216	$ 9,577
Natural gas distribution	29,444	28,996	30,656
Pipeline and energy services	10,516	9,064	8,896
Exploration and production	7,445	8,580	10,621
Construction materials and contracting	16,241	19,859	20,495
Construction services	4,473	4,411	4,490
Other	—	47	43
Intersegment eliminations	(510)	(162)	(679)
Total interest expense	$ 81,354	$ 83,011	$ 84,099
Income taxes:			
Electric	$ 7,242	$ 11,187	$ 8,205
Natural gas distribution	16,931	12,171	16,331
Pipeline and energy services	12,912	13,933	22,982
Exploration and production	46,298	49,034	(187,000)
Construction materials and contracting	11,227	13,822	25,940
Construction services	13,426	11,456	15,189
Other	2,238	10,927	2,261
Total income taxes	$ 110,274	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			
Electric	$ 29,258	$ 28,908	$ 24,099
Natural gas distribution	38,398	36,944	30,796
Pipeline and energy services	23,082	23,208	37,845
Exploration and production	80,282	85,638	(296,730)
Construction materials and contracting	26,430	29,609	47,085
Construction services	21,627	17,982	25,589
Other	6,190	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	225,267	243,335	(123,959)
Loss from discontinued operations, net of tax*	(12,926)	(3,361)	—
Total earnings (loss) on common stock	$ 212,341	$ 239,974	$ (123,959)
Capital expenditures:			
Electric	$ 52,072	$ 85,787	$ 115,240
Natural gas distribution	70,624	75,365	43,820
Pipeline and energy services	45,556	14,255	70,168
Exploration and production	272,855	355,845	183,140
Construction materials and contracting	52,303	25,724	26,313
Construction services	9,711	14,849	12,814
Other	18,759	2,182	3,196
Net proceeds from sale or disposition of property and other	(40,857)	(78,761)	(26,679)
Total net capital expenditures	$ 481,023	$ 495,246	$ 428,012

	2011	2010	2009
		(In thousands)	
Assets:			
Electric**	$ **672,940**	$ 643,636	$ 569,666
Natural gas distribution**	**1,679,091**	1,632,012	1,588,144
Pipeline and energy services	**526,797**	523,075	538,230
Exploration and production	**1,481,556**	1,342,808	1,137,628
Construction materials and contracting	**1,374,026**	1,382,836	1,449,469
Construction services	**418,519**	387,627	328,895
Other***	**403,196**	391,555	378,920
Total assets	$ **6,556,125**	$ 6,303,549	$ 5,990,952
Property, plant and equipment:			
Electric**	$ **1,068,524**	$ 1,027,034	$ 941,791
Natural gas distribution**	**1,568,866**	1,508,845	1,456,208
Pipeline and energy services	**719,291**	683,807	675,199
Exploration and production	**2,615,146**	2,356,938	2,028,794
Construction materials and contracting	**1,499,852**	1,486,375	1,514,989
Construction services	**124,796**	122,940	116,236
Other	**49,747**	32,564	33,365
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	2,872,465
Net property, plant and equipment	$ **4,285,014**	$ 4,115,180	$ 3,894,117

* *Reflected in the Other category.*

** *Includes allocations of common utility property.*

*** *Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).*

Note: The results reflect a $620.0 million ($384.4 million after tax) noncash write-down of natural gas and oil properties in 2009.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2011, 2010 and 2009 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ **388,589**	$ 352,915	$ **91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$ **—**	$ —	$ **(550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$ **189,494**	$ 117,840	$ **43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	$ **188,862**	$ 118,471	$ **37,374**	$ 13,712

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31 were as follows:

	2011	2010
	(In thousands)	
Projected benefit obligation	**$ 435,618**	$ 388,589
Accumulated benefit obligation	**$ 435,618**	$ 374,538
Fair value of plan assets	**$ 278,000**	$ 277,598

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ **2,252**	$ 2,889	$ 8,127	$ **1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	—	—	—
Amortization of net transition obligation	—	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	—	353	—	—	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	—	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	$ **74,057**	$ 19,046	$ (25,143)	$ **25,005**	$ 2,337	$ (9,765)

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $1.9 million, $1.1 million and $2.1 million, respectively.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	4.00%	**4.00%**	4.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**5.26%**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75%**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**4.00% / N/A***	4.00%	**4.00%**	4.00%

* *Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.*

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2011	2010
Health care trend rate assumed for next year	**6.0% - 8.0%**	6.0% - 8.5%
Health care cost trend rate - ultimate	**5.0% - 6.0%**	5.0% - 6.0%
Year in which ultimate trend rate achieved	**1999 - 2017**	1999 - 2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The fair value of the Company's pension net plan assets by class is as follows:

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Collateral Held on Loaned Securities	
	(In thousands)	
Balance at beginning of year	$	937
Total realized/unrealized losses		189
Purchases, issuances and settlements (net)		(432)
Balance at end of year	$	694

The fair value of the Company's other postretirement benefit plan assets by asset class is as follows:

	Fair Value Measurements at December 31, 2011, Using							
		Quoted Prices in Active Markets for Identical Assets (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)		Balance at December 31, 2011
	(In thousands)							
Assets:								
Cash equivalents	$	59	$	1,836	$	—	$	1,895
Equity securities:								
U.S. companies		2,098		—		—		2,098
International companies		262		—		—		262
Insurance investment contract*		—		63,830		—		63,830
Total assets measured at fair value	$	2,419	$	65,666	$	—	$	68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using							
		Quoted Prices in Active Markets for Identical Assets (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)		Balance at December 31, 2010
	(In thousands)							
Assets:								
Cash equivalents	$	53	$	1,274	$	—	$	1,327
Equity securities:								
U.S. companies		2,791		—		—		2,791
International companies		353		—		—		353
Insurance investment contract*		—		66,139		—		66,139
Total assets measured at fair value	$	3,197	$	67,413	$	—	$	70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4.00 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers

- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2011	Pension Protection Act Zone Status 2010	FIP/RP Status Pending/ Implemented	Contributions 2011	Contributions 2010	Contributions 2009	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	$ **2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					**$ 29,158**	$ 30,276	$ 32,479		

** Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.*

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $24.0 million, $24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's 22.7 percent, 25.0 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III, respectively. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

		2011		2010
		(In thousands)		
Big Stone Station:				
Utility plant in service	$	63,715	$	60,404
Less accumulated depreciation		42,475		41,136
	$	21,240	$	19,268
Coyote Station:				
Utility plant in service	$	131,719	$	131,395
Less accumulated depreciation		86,788		84,710
	$	44,931	$	46,685
Wygen III:*				
Utility plant in service	$	63,300	$	63,215
Less accumulated depreciation		2,106		838
	$	61,194	$	62,377

** Began commercial operation on April 1, 2010.*

Note 18 - Regulatory Matters and Revenues Subject to Refund

On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012.

On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012.

On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

Guarantees
Centennial guaranteed CEM's obligations under a construction contract. For further information, see Litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Definitions

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the fourth quarter of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (7.51 percent ownership interest at December 31, 2011, 2.5 and 14.99 percent ownership interest was sold in 2011 and 2010, respectively)

EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu

MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent - natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
Oil	Includes crude oil, condensate and natural gas liquids
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
PRC	Planning resource credit - a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2012 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of natural gas and oil during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SMCRA	Surface Mining Control and Reclamation Act
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada

WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Docket No. ____
Rule 38.5.122
Statement B

INDEX

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2011

Operating Income	
Electric Utility	
Operating Revenues	$223,201,621
Operating Expenses:	
Operation Expenses	114,687,315
Maintenance Expenses	17,703,292
Depreciation Expenses	32,005,151
Taxes Other Than Income Taxes	9,434,923
Income Taxes:	
Federal Taxes on Income	(12,586,738)
State Taxes on Income	(1,265,099)
Deferred Income Taxes	21,167,194
Total Electric Expenses	181,146,038
Net Electric Operation	$42,055,583
Gas Utility	
Operating Revenues	$282,824,029
Operating Expenses:	
Operation Expenses	245,406,477
Maintenance Expenses	3,630,918
Depreciation Expenses	11,248,859
Taxes Other Than Income Taxes	6,935,664
Income Taxes:	
Federal Taxes on Income	(10,601,531)
State Taxes on Income	(1,461,534)
Deferred Income Taxes	14,025,870
Total Gas Expenses	269,184,723
Net Gas Operation	$13,639,306
Net Utility Operating Income	$55,694,889
Revenues from Merchandising, Jobbing and Contract Work	$6,056,315
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	4,666,614
Revenues from Nonutility Operations	4,113,607
(Less) Expense from Nonutility Operations	2,581,985
Equity in Earnings of Subsidiary Companies	171,763,717
Interest and Dividend Income	1,717,382
Allowance for Other Funds Used During Construction	2,056,639
Miscellaneous Nonoperating Income	35,717
Gain on Disposition of Property	228,379
Total Other Income	178,723,157
Loss on Disposition of Property	(4,772)
Miscellaneous Income Deductions	1,315,568
Total Other Income Deductions	1,310,796

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2011

Taxes other than Income Taxes	3,678
Income Taxes - Federal	877,615
Income Taxes - State	332,819
Provision for Deferred Income Taxes	133,398
Investment Tax Credits	73,338
Total Taxes on Other Income and Deductions	1,420,848
Net Other Income and Deductions	$175,991,513
Interest On Long-Term Debt	17,773,282
Amortization of Debt Discount and Expense	97,309
Amortization of Loss on Reacquired Debt	719,510
Other Interest Expense	1,234,189
(Less) Allow for Borrowed Funds Used during Const.	1,164,234
Net Interest Charges	18,660,056
Net Income	$213,026,346

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
SIX MONTHS ENDING JUNE 30, 2012

Operating Income	
Electric Utility	
Operating Revenues	$110,350,568
Operating Expenses:	
Operation Expenses	59,004,234
Maintenance Expenses	9,637,198
Depreciation Expenses	15,981,140
Taxes Other Than Income Taxes	5,295,666
Income Taxes:	
Federal Taxes on Income	(3,330,057)
State Taxes on Income	(180,119)
Deferred Income Taxes	6,733,525
Total Electric Expenses	93,141,587
Net Electric Operation	$17,208,981
Gas Utility	
Operating Revenues	$120,973,856
Operating Expenses:	
Operation Expenses	101,181,009
Maintenance Expenses	1,992,632
Depreciation Expenses	5,781,526
Taxes Other Than Income Taxes	3,840,139
Income Taxes:	
Federal Taxes on Income	561,935
State Taxes on Income	(5,236)
Deferred Income Taxes	1,478,842
Total Gas Expenses	114,830,847
Net Gas Operation	$6,143,009
Net Utility Operating Income	$23,351,990
Revenues from Merchandising, Jobbing and Contract Work	$2,792,402
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	1,920,823
Revenues from Nonutility Operations	2,528,390
(Less) Expense from Nonutility Operations	1,694,800
Equity in Earnings of Subsidiary Companies	71,460,782
Interest and Dividend Income	1,219,781
Allowance for Other Funds Used During Construction	983,521
Miscellaneous Nonoperating Income	(6,361)
Gain on Disposition of Property	(28)
Total Other Income	75,362,864
Loss on Disposition of Property	0
Miscellaneous Income Deductions	212,612
Total Other Income Deductions	212,612

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
SIX MONTHS ENDING JUNE 30, 2012

Taxes other than Income Taxes	2,764
Income Taxes - Federal	(64,283)
Income Taxes - State	3,781
Provision for Deferred Income Taxes	(156,728)
Investment Tax Credits	(27,654)
Total Taxes on Other Income and Deductions	(242,120)
Net Other Income and Deductions	$75,392,372
Interest On Long-Term Debt	8,888,820
Amortization of Debt Discount and Expense	46,912
Amortization of Loss on Reacquired Debt	359,756
Other Interest Expense	165,899
(Less) Allow for Borrowed Funds Used during Const.	620,776
Net Interest Charges	8,840,611
Net Income	$89,903,751

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PLANT IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Pro Forma Adjustment 1/	Pro Forma Balance @ 12/31/12
Production	$2,972,781	$3,096,756	$3,034,769	$74,440	$3,109,209
Distribution	70,105,115	73,250,276	71,677,695	3,110,478	74,788,173
General	5,953,718	6,010,708	5,982,213	309,909	6,292,122
General Intangible	56,115	55,404	55,759	(355)	55,404
Common	10,639,185	10,552,679	10,595,932	166,437	10,762,369
Common Intangible	2,697,442	2,821,499	2,759,471	2,696,713	5,456,184
Subtotal	92,424,356	95,787,322	94,105,839	6,357,622	100,463,461
Construction Work in Progress (CWIP) in Service not yet Classified 2/	442,264	500,474	500,474		500,474
Total	$92,866,620	$96,287,796	$94,606,313	$6,357,622	$100,963,935

1/ Page 2.
2/ CWIP in Service is reflected at the year end balance. See Rule 38.5.124, Statement C, page 4.

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Additions to Plant 1/	Pro Forma Balance @ 12/31/12	Average Balance @ 12/31/12	Pro Forma Adjustment
Production	$2,972,781	$3,096,756	$3,034,769	$24,906	$3,121,662	$3,109,209	$74,440
Distribution	70,105,115	73,250,276	71,677,695	3,075,794	76,326,070	74,788,173	3,110,478
General	5,953,718	6,010,708	5,982,213	562,825	6,573,533	6,292,122	309,909
General Intangible	56,115	55,404	55,759		55,404	55,404	(355)
Common	10,639,185	10,552,679	10,595,932	419,378	10,972,057	10,762,369	166,437
Common Intangible	2,697,442	2,821,499	2,759,471	5,269,371	8,090,870	5,456,184	2,696,713
Subtotal	92,424,356	95,787,322	94,105,839	9,352,274	105,139,596	100,463,461	6,357,622
Construction Work in Progress (CWIP) in Service not yet Classified 2/	442,264	500,474	500,474		500,474	500,474	
Total	$92,866,620	$96,287,796	$94,606,313	$9,352,274	$105,640,070	$100,963,935	$6,357,622

1/ See Rule 38.5.124, Statement C, pages 5 through 7.
2/ CWIP in Service is reflected at the year end balance. See Rule 38.5.124, Statement C, page 4.

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT A

					Pro Forma			
Acct. No.	Account	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Plant Additions 1/	Balance @ 12/31/12	Average Balance @ 12/31/12	Adjustment
	Production Plant							
333	Other Gas Production Equipment	$2,972,781	$3,096,756	$3,034,769	$24,906	$3,121,662	$3,109,209	$74,440
	Distribution Plant							
374.1	Land	$15,962	$15,962	$15,962		$15,962	$15,962	
374.2	Rights of Way	22,846	22,846	22,846		22,846	22,846	
375	Structures & Improvements	195,164	195,164	195,164		195,164	195,164	
376	Mains	28,343,409	28,903,239	28,623,324	1,354,848	30,258,087	29,580,663	$957,339
378	Meas. & Reg. Equip.-General	575,341	577,021	576,181	26,647	603,668	590,345	14,164
379	Meas. & Reg. Equip.-City Gate	128,221	128,222	128,222		128,222	128,222	
380	Services	19,708,913	21,208,457	20,458,685	1,149,831	22,358,288	21,783,372	1,324,687
381	Positive Meters	17,741,728	18,493,911	18,117,819	395,073	18,888,984	18,691,448	573,629
383	Service Regulators	1,908,710	2,130,129	2,019,419	42,090	2,172,219	2,151,173	131,754
385	Ind. Meas. & Reg. Station Eqpt.	187,825	187,825	187,825		187,825	187,825	
386.2	Other Property on Cust. Premise	148,674	148,673	148,673		148,673	148,673	
387.1	Cathodic Protection Equip.	1,010,665	1,121,405	1,066,035	107,305	1,228,710	1,175,058	109,023
387.2	Other Distribution Equip.	117,657	117,422	117,540		117,422	117,422	(118)
	Total Distribution Plant	$70,105,115	$73,250,276	$71,677,695	$3,075,794	$76,326,070	$74,788,173	$3,110,478
	General Plant							
389	Land	$7,131	$7,131	$7,131		$7,131	$7,131	
390	Structures and Improvements	449,416	449,416	449,416		449,416	449,416	
391.1	Furniture and Fixtures	50,780	48,359	49,570		48,359	48,359	(1,211)

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT A

					Pro Forma			
Acct. No.	Account	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Plant Additions 1/	Balance @ 12/31/12	Average Balance @ 12/31/12	Adjustment
391.3	Computer Equip. - PC	47,979	51,081	49,530		51,081	51,081	1,551
391.5	Computer Equip. - Other	14,561	14,561	14,561		14,561	14,561	
392.1	Trans. Equip., Non-Unitized	91,540	117,486	104,513		117,486	117,486	12,973
392.2	Trans. Equip., Unitized	2,206,436	2,255,615	2,231,025	139,603	2,395,218	2,325,417	94,392
393	Stores Equipment	43,786	14,254	29,020		14,254	14,254	(14,766)
394.1	Tools,Shop&Gar. Eq.-Non-Un.	813,182	663,334	738,258	64,203	727,537	695,436	(42,822)
394.3	Vehicle Maintenance Equip.	22,859	22,859	22,859		22,859	22,859	
395	Laboratory Equipment	37,072	32,303	34,688		32,303	32,303	(2,385)
396.1	Power Operated Equip.	138,401	151,847	145,124		151,847	151,847	6,723
396.2	Work Equipment Trailers	1,580,659	1,789,764	1,685,211	347,473	2,137,237	1,963,501	278,290
397.1	Radio Comm. Equip.-Fixed	236,876	237,224	237,050	11,546	248,770	242,997	5,947
397.2	Radio Comm. Equip.-Mobile	197,928	140,365	169,147		140,365	140,365	(28,782)
398	Miscellaneous Equipment	15,112	15,109	15,110		15,109	15,109	(1)
	Total General Plant	$5,953,718	$6,010,708	5,982,213	$562,825	$6,573,533	$6,292,122	$309,909
303	Intangible Plant - General	$56,115	$55,404	$55,759		$55,404	$55,404	($355)
	Common Plant							
389	Land	$952,893	$988,648	$970,771		$988,648	$988,648	$17,877
390	Structures and Improvements	7,115,215	6,978,927	7,047,071	53,796	7,032,723	7,005,825	(41,246)
391.1	Furniture and Fixtures	384,341	497,432	440,886	83,974	581,406	539,419	98,533
391.3	Computer Equip. - PC	349,039	391,997	370,518	57,512	449,509	420,753	50,235
391.5	Computer Equip. - Other	96,481	11,912	54,197		11,912	11,912	(42,285)

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT A

Acct. No.	Account	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Pro Forma Plant Additions 1/	Pro Forma Balance @ 12/31/12	Pro Forma Average Balance @ 12/31/12	Pro Forma Adjustment
392.1	Trans. Equip., Non-Unitized	6,228	6,203	6,215		6,203	6,203	(12)
392.2	Trans. Equip., Unitized	543,334	584,835	564,085	66,479	651,314	618,075	53,990
392.3	Aircraft	466,754	483,574	475,164		483,574	483,574	8,410
393	Stores Equipment	10,796	10,773	10,784		10,773	10,773	(11)
394	Tools, Shop & Gar. Equip.	46,925	53,148	50,037	14,211	67,359	60,254	10,217
394.3	Vehicle Maint. Equip.	44,019	44,545	44,282		44,545	44,545	263
394.4	Vehicle Refueling Equip.	66,439	28,124	47,281		28,124	28,124	(19,157)
396.2	Work Equipment Trailers	6,458		3,229				(3,229)
397.1	Radio Comm. Equip.-Fixed	160,188	149,997	155,093	63,425	213,422	181,709	26,616
397.2	Radio Comm. Equip.-Mobile	100,652	77,331	88,991		77,331	77,331	(11,660)
397.3	General Tele. Comm. Equip.	40,103	76,218	58,161	58,374	134,592	105,405	47,244
397.5	Supervisory & Tele. Equip.	450	223	336		223	223	(113)
397.8	Network Equipment	122,906	56,252	89,579	8,479	64,731	60,492	(29,087)
398	Miscellaneous Equipment	125,964	112,540	119,252	13,128	125,668	119,104	(148)
	Total Common Plant	$10,639,185	$10,552,679	$10,595,932	$419,378	$10,972,057	$10,762,369	$166,437
303	Intangible Plant - Common	$2,697,442	$2,821,499	$2,759,471	$5,269,371	$8,090,870	$5,456,184	$2,696,713
	Total Gas Plant in Service	$92,424,356	$95,787,322	$94,105,839	$9,352,274	$105,139,596	$100,463,461	$6,357,622

1/ See Rule 38.5.124, Statement C, pages 5 through 7.

Docket No. ____
Rule 38.5.123
Statement C
Page 5 of 5

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Acct. No.	Account	Balance @ 12/31/10	Additions	Retirements	Transfers	Balance @ 12/31/11
	Production Plant					
333	Other Gas Production Equipment	10,280,260.00	$497,907			$10,778,167
	Distribution Plant					
374.1	Land	138,262	138,672			276,934
374.2	Rights of Way	299,784	68,142			367,926
375	Structures & Improvements	594,031	62,050	(481)		655,600
376	Mains	113,003,676	7,041,727	(339,013)		119,706,390
378	Meas. & Reg. Equip.-General	2,284,074	223,100	(822)	(97,990)	2,408,362
379	Meas. & Reg. Equip.-City Gate	1,201,727	514,851	(15,454)		1,701,124
380	Services	57,112,318	4,737,764	(187,230)	97,990	61,760,842
381	Positive Meters	55,515,836	3,324,796	(439,009)	(115,880)	58,285,743
383	Service Regulators	5,951,207	745,546	(8,330)	(22,784)	6,665,639
385	Ind. Meas. & Reg. Station Eqpt.	786,435				786,435
386.1	Misc. Property on Customer Premise	1,680				1,680
386.2	Other Property on Cust. Premise	261,880				261,880
387.1	Cathodic Protection Equip.	2,227,880	213,504	(34,764)		2,406,620
387.2	Other Distribution Equip.	588,025			(874)	587,151
	Total Distribution Plant	$239,966,815	$17,070,152	($1,025,103)	($139,538)	$255,872,326
	General Plant					
389	Land	$1,304,244			$180,000	$1,484,244
390	Structures and Improvements	8,765,485	18,814	(2,320)	(182,754)	8,599,225
391.1	Furniture and Fixtures	417,051	3,687	(65,025)		355,713
391.3	Computer Equip. - PC	378,057	71,666		13,950	463,673
391.5	Computer Equip. - Other	54,036				54,036
392.1	Trans. Equip., Non-Unitized	402,969	80,994	(30,127)	(5,964)	447,872
392.2	Trans. Equip., Unitized	7,737,722	420,133	(231,437)	28,837	7,955,255
393	Stores Equipment	148,282		(84,678)		63,604
394.1	Miscellaneous Tools - Utilized	2,749,126	174,374	(835,901)	4,135	2,091,734

MONTANA-DAKOTA UTILITIES CO.
DETAILED COST OF PLANT
GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Acct. No.	Account	Balance @ 12/31/10	Additions	Retirements	Transfers	Balance @ 12/31/11
394.3	Vehicle Maintenance Equipment	37,100				37,100
394.4	Vehicle Refueling Equipment	26,853		(14,409)		12,444
395	Laboratory Equipment	231,841		(14,489)		217,352
396.1	Power Operated Equip.	519,639	76,754	(8,753)	(17,665)	569,975
396.2	Work Equipment Trailers	6,425,348	2,822,838	(2,327,229)	77,071	6,998,028
397.1	Fixed Radio Comm. Equipment	510,934	33,614	(19,363)	4,946	530,131
397.2	Moblile Radio Comm. Equipment	675,941	19,766	(291,645)	(14,725)	389,337
397.3	General Telephone Comm. Equipment	60,470				60,470
397.8	Network Equipment	180,882	(6,514)	(37,034)		137,334
398	Miscellaneous Equipment	56,850	2,282			59,132
	Total General Plant	$30,682,830	$3,718,408	($3,962,410)	$87,831	$30,526,659
303	Intangible Plant - General	2,660,120				2,660,120
	Common Plant - Gas 1/	21,320,406				21,351,029
	Common Intangible Plant 2/	9,046,809				9,609,576
	Acquisition Adjustment	97,266				97,266
	Total Gas Plant in Service	$314,054,506	$21,286,467	($4,987,513)	($51,707)	$330,895,143

1/ Common plant is either directly assigned or allocated to gas and electric plant. Total common plant additions, retirements, transfers and adjustments for the twelve months ended December 31, 2011 are $1,512,387, ($2,338,478) and ($144,396) respectively.

2/ Common intangible plant is either directly assigned or allocated to gas and electric plant. Total common intangible plant additions for the twelve months ended December 31, 2011 are $181,717.

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN GAS PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2011

Work Order #	Description	Location	Construction Period	Date Placed In Service	Beginning Balance	Major Additions	Major Retirements	Transfers	Ending Balance
					$283,590,025				
J183900	Install main extension to Craven grain elevator	SD	5/23/11-10/7/11	10/7/2011		1,637,602			
J155901	Install main and purchase 2 laterals from WBI in Rapid City	SD	4/1/11-11/30/11	11/30/2011		1,353,325			
J169750	Upgrade main in downtown Buffalo	WY	10/15/09-9/2/11	9/2/2011		$589,651			
J159744	Develop gas production in Billings Landfill	MT	8/31/08-12/7/10	12/7/2010		497,907			
J176840	Intall gas ERT's meters	1/	4/1/11-9/9/11	9/9/2011		493,844			
J185517	Replace main by Highway 83 bypass in Minot	ND	8/1/11-10/1/11	10/1/2011		468,102			
	Major Projects Subtotal				283,590,025	5,040,430			
	Miscellaneous Projects					16,246,036	(4,987,513)	(51,708)	
	Subtotal				283,590,025	21,286,467	(4,987,513)	(51,708)	299,837,272
	Common Plant Allocated to Gas				30,367,215				30,960,605
	Total Gas Plant				$313,957,240				$330,797,876

1/ Located in various locations.

MONTANA-DAKOTA UTILITIES CO.
GAS CWIP IN SERVICE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Work Order Number	Description	State	Total	Distribution	General	Common	Intangible
J159769	Replace Main - Blue Water Road-Fromberg	MT	$99,389	$99,389			
J165129	Install Main to Water Plant - Wolf Point	MT	11	11			
J176840, 176842	Install Gas ERT	MT	12,584	12,584			
J176901	Reinforce Distribution System - Billings	MT	70,841	70,841			
J182312	Purchase Toughbooks for mobile computing	ND	36			$36	
J165742	Purchase GIS Utility Software	ND	(249)				($249)
Small items grouped 1/:							
	Distribution (59)	MT	$199,642	$199,642			
	General (5)	MT	51,213		$51,213		
	Common (14)	MT	67,007			$67,007	
	Total		$500,474	$382,467	$51,213	$67,043	($249)

1/ Numbers in brackets indicate the number of work orders involved in each item of construction.

MONTANA-DAKOTA UTILITIES CO.
PLANT ADDITIONS SUMMARY
GAS UTILITY - MONTANA

	Montana
Production	$24,906
Distribution	3,075,794
General	
Other	423,222
Transportation	139,603
Total General Plant	562,825
Common	
Other	241,591
Structures & Improvements	53,796
Transportation	66,479
Computer Equipment	57,512
Total Common Plant	419,378
Intangible Plant Common	5,269,371
Total Additions	$9,352,274

MONTANA-DAKOTA UTILITIES CO.
2012 PLANT ADDITIONS
GAS UTILITY - MONTANA

Project No.	Acct. #	Description	Montana	Region
		Production		
J189385	320	Landfill Gas Field Expansion	$24,906	Rocky Mountain
		Total Production	$24,906	
		Distribution		
B11230R,B15230R	376	Replace Mains	$504,015	Rocky Mountain/Badlands
J176140, J192226	376	Replace Main - Belfry	90,010	Rocky Mountain
J177092	376	Replace Phase 3 Loop - Glendive	55,917	Badlands
J177093	376	Replace Phase 2 Loop - Wibaux	39,142	Badlands
J177163	376	Replace 4" Main on Bench - Billings	22,506	Rocky Mountain
J190553	376	Replace Main Ave B East - Billings	129,305	Rocky Mountain
J192403	376	Install Mains and Services - Billings	31,853	Rocky Mountain
J194149	376	Replace Mains Rimrock Road area - Billings	482,100	Rocky Mountain
B11234, B15234	378	Measuring and Regulating Equipment	26,647	Rocky Mountain/Badlands
B11233, B15233	380	Service Lines	969,829	Rocky Mountain/Badlands
J190554	380	Replace Main Ave B-E Services - Billings	180,002	Rocky Mountain
B90031	381	Meters	395,073	General Office
B90032	383	Regulators	42,090	General Office
B11235, B15235	387	Cathodic Protection	107,305	Rocky Mountain/Badlands
		Total Distribution	$3,075,794	
		General		
B90038	392.2	Gas Vehicles	$139,603	General Office
B11243, B15243	394.1	Minor Work Equipment	64,203	Rocky Mountain/Badlands
B90039	396.2	Gas Work Equipment	347,473	Rocky Mountain
B11244	397.1	Communication Equipment - Billings	11,546	Rocky Mountain
		Total General	$562,825	
		Common		
J177018	390	Replace Transportation Building Roof	$4,947	General Office
J177021	390	Install Valves-Thermo - Annex	13,564	General Office
J177165	390	Purchase backup Generator - Glendive	19,077	Badlands
J177166	390	Replace siding front of Wolf Point office	4,059	Badlands
J177168	390	Hydraulic gate for Dickinson Service Center	5,011	Badlands
J177176	390	Replace roof of Dickinson office	7,138	Badlands

MONTANA-DAKOTA UTILITIES CO.
2012 PLANT ADDITIONS
GAS UTILITY - MONTANA

Project No.	Acct. #	Description	Montana	Region
J177035	391.1	Purchase Tandem Storage Units	4,027	General Office
J177042	391.1	Purchase Color Copier	15,797	General Office
J177043	391.1	Purchase B/W Copier	19,592	General Office
J177063	391.1	Purchase Bill Printer	29,594	General Office
B15282, B90082	391.1	Office Equipment	14,964	Badlands/General Office
B90080	391.3	Personal Computers	30,326	General Office
J144522	391.3	Purchase 50 replacement MDTs	16,340	General Office
J190782	391.3	Add Oracle Exadata Platforms	10,846	General Office
B90078	392.2	Vehicles	66,479	General Office
B15283, B90083	394.1	Minor Work Equipment	14,211	Badlands/General Office
B15244, B15284, B90084	397.1	Communication Equipment	63,425	Badlands/General Office
J177192	397.3	Replace General Office Phone System	47,553	General Office
J177193	397.3	Replace Call Record System - Call Center	10,821	General Office
B90081	397.8	Network Equipment	2,217	General Office
J157230	397.8	Install Network &Comm. Equip.- AMR	3,278	General Office
J177134	397.8	Purchase Polycom units for Conf.Rooms	2,984	General Office
J177020	398	Purchase CTP Equipment - Print Shop	7,505	General Office
J177074	398	Purchase DC645 Cut/CRSR	3,175	General Office
J177132	398	Replace UPS Battery	562	General Office
J177167	398	Purchase Ice Maker - Wolf Point	978	Badlands
J177169	398	Purchase Ice Machine - Dickinson	347	Badlands
J177132	398	Purchase Pressure Washer - Dickinson	561	Badlands
		Total Common	$419,378	
		Common - Intangible		
J165746	303	Replace Mobile Workforce Software	$95,402	General Office
J172806	303	Replace Customer Info System	4,937,603	General Office
J176834	303	Purchase/Deploy ARCGIS Mobile	41,034	General Office
J176841	303	Purchase Automated Vehicle Loc. Software	19,900	General Office
J177281	303	Purchase Powerplan Software	130,262	General Office
J181432	303	Purchase IVR-Web Direct	45,170	General Office
			$5,269,371	
Total Plant Additions			$9,352,274	

MONTANA-DAKOTA UTILITIES CO.
METHODS AND PROCEDURES FOLLOWED IN CAPITALIZING
THE ALLOWANCE FOR FUNDS USED DURING
CONSTRUCTION AND OTHER CONSTRUCTION OVERHEADS

There has been no change in the methodology employed or the procedures followed in capitalizing the allowance for funds used during construction and other construction overheads as was reported in the Company's last FERC Form 1.

MONTANA-DAKOTA UTILITIES CO.
SIGNIFICANT CHANGES IN
INTANGIBLE PLANT

There have been no significant changes in Intangible Plant balances since the end of the year reported in the Company's last FERC Form 1.

MONTANA-DAKOTA UTILITIES CO.
WORKING PAPERS ON PLANT
NOT USED & USEFUL

Montana-Dakota has no such plant.

MONTANA-DAKOTA UTILITIES CO.
DESCRIPTION OF PROPERTY RECORDS

The Company's Continuing Property Records are maintained in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC). The Plant Accounting System, which is computerized, records additions to utility plant at original cost (including overhead costs and an allowance for funds used during construction) through charges to work orders maintained in the Plant Accounting Construction Work in Progress (CWIP) System. As construction projects are completed and the plant is placed in service, the costs accumulated in related work orders are unitized and transferred to the appropriate sub plant account of Account 101, Plant in Service. Such costs are recovered from utility customers through depreciation charges to cost of service. Upon retirement or other disposition of the plant property units, in the ordinary course of business, the original cost is transferred from Account 101 and charged to Account 108, Accumulated Provision for Depreciation of Utility Plant, plus or minus any net salvage.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Pro Forma Adjustment 1/	Pro Forma Balance @ 12/31/12
Production		$101,594	$50,797	$102,565	$153,362
Distribution	$42,010,598	43,776,099	42,893,349	2,607,909	45,501,258
General	3,281,698	3,073,666	3,177,682	(32,987)	3,144,695
General Intangible	56,115	55,405	55,760	(355)	55,405
Common	2,937,562	3,016,552	2,977,057	210,513	3,187,570
Common Intangible	2,010,597	2,198,479	2,104,538	315,001	2,419,539
CWIP in Service				2/	2/
Total	$50,296,570	$52,221,795	$51,259,183	$3,202,646	$54,461,829

1/ Page 2.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT B

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Provision for Depreciation 1/	Pro Forma Balance @ 12/31/12	Average Balance @ 12/31/12	Pro Forma Adjustment
Production		$101,594	$50,797	$103,537	$205,131	$153,362	$102,565
Distribution	$42,010,598	43,776,099	42,893,349	3,450,318	47,226,417	45,501,258	2,607,909
General	3,281,698	3,073,666	3,177,682	142,058	3,215,724	3,144,695	(32,987)
General Intangible	56,115	55,405	55,760	0	55,405	55,405	(355)
Common	2,937,562	3,016,552	2,977,057	342,037	3,358,589	3,187,570	210,513
Common Intangible	2,010,597	2,198,479	2,104,538	442,119	2,640,598	2,419,539	315,001
CWIP in Service				2/	2/	2/	2/
Total	$50,296,570	$52,221,795	$51,259,183	$4,480,069	$56,701,864	$54,461,829	$3,202,646

1/ See Rule 38.5.165, Statement I, pages 3 - 4 for the provision for depreciation.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Gas Utility	Beginning Balance 12/31/2010	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Reclass/ Adjustments	Ending Balance 12/31/2011
Account 111 - Intangible	$622,587	$55,248					$677,835
Account 108							
Production		353,594					353,594
Distribution	142,461,822	7,685,898	1,025,536	25,628	643,521	31,346	148,472,945
General	12,802,286	751,981	3,962,410	2,469,133	5,250	(163,012)	12,218,752
Total Account 108	155,264,108	8,791,473	4,987,946	2,494,761	648,771	(131,666)	161,045,291
Total	$155,886,695	$8,846,721	$4,987,946	$2,494,761	$648,771	($131,666)	$161,723,126
Common 1/	$14,889,306						$15,695,845

1/ Common Plant is assigned by state on an actual site and use basis when applicable, and the remainder is allocated by state to gas and electric on a plant in service basis. Total common changes for the twelve months ended December 31, 2011 are:

Common Utility	Beginning Balance 12/31/2010	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/2011
Account 111	$18,094,547	$989,651					$19,084,198
Account 108	23,465,082	1,865,867	2,316,918	305,121	6,577	296,273	23,016,302
Total Accounts 111 and 108	$41,559,629	$2,855,518	$2,316,918	$305,121	$6,577	$296,273	$42,100,500

MONTANA-DAKOTA UTILITIES CO.
PROCEDURES FOLLOWED IN DEPRECIATING OR AMORTIZING PLANT AND RECORDING ABANDONMENT

There has been no policy change with respect to the methodology employed or Procedures followed in depreciating and amortizing plant investments and Recording plant abandonments since the end of the year reported in the Company's last FERC Form 1.

MONTANA-DAKOTA UTILITIES CO.
ALLOCATION OF OVERALL ACCUMULATED RESERVE ACCOUNTS TO FUNCTIONAL GROUPS OF PLANTS

This schedule is not applicable because the Company provides and records its accumulated reserves for depreciation by functional groups of plant accounts.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND OTHER DEDUCTIONS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Working Capital	Balance @ 12/31/10	Balance @ 12/31/11	Average	Pro Forma Adjustments	Pro Forma Balances	Adjustment
Materials and Supplies	$508,979	$557,694	$533,337	$99,695	$633,032	C
Gas in Underground Storage	6,702,686	7,566,845	7,134,766	(855,502)	6,279,264	D
Prepayments						
Insurance	23,075	28,741	25,908	93,808	119,716	E
Demand and Commodity	1,086,349	1,213,615	1,149,981	(642,915)	507,066	F
Unamortized Loss on Debt	631,135	538,504	584,820	(53,806)	531,014	G
Provision for Pension & Benefits				1,268,837	1,268,837	H
Provision for Injuries & Damages				(109,736)	(109,736)	I
Deferred FAS 106 Balance	148,226	109,558	128,892	273,775	402,667	J
Total Working Capital	$9,100,450	$10,014,957	$9,557,704	$74,156	$9,631,860	
Customer Advances for Construction	$770,737	$683,775	$727,256	($20,926)	$706,330	N

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
BY PRINCIPAL ITEM OF MAIN ACCOUNT
GAS UTILITY - MONTANA
DECEMBER 31, 2010 AND DECEMBER 31, 2011

Description	Balance @ 12/31/10	Balance @ 12/31/11	Beginning & Ending Average
Natural Gas Material	$534,018	$576,363	$555,191
Transportation Material	921	1,627	1,274
Reserve for Inventory Shrinkage	(25,960)	(20,296)	(23,128)
Total	$508,979	$557,694	$533,337

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT C

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$508,979	$557,694	
January 2011	491,311	571,628	
February	490,913	609,874	
March	483,398	609,597	
April	553,150	672,668	
May	559,282	824,045	
June	567,033	862,822	
July	573,017	573,017	
August	567,190	567,190	
September	607,577	607,577	
October	609,349	609,349	
November	606,259	606,259	
December	557,694	557,694	
Beginning and ending average	$533,337		
Thirteen month average		$633,032	$99,695

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects per books 2011.

MONTANA-DAKOTA UTILITIES CO.
GAS IN UNDERGROUND STORAGE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT D

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$6,702,686	$7,566,845	
January 2011	3,072,842	5,288,653	
February	(103,277)	3,279,980	
March	(1,865,166)	3,263,233	
April	(1,935,039)	3,670,275	
May	(722,093)	4,755,047	
June	1,462,708	6,049,593	
July	4,109,292	7,436,157	
August	6,884,778	8,380,580	
September	9,880,135	9,015,463	
October	11,499,125	8,977,527	
November	10,018,059	8,212,063	
December	7,566,845	5,735,018	
Beginning and ending average	$7,134,766		
Thirteen month average		$6,279,264	($855,502)

1/ Reflects actual balances December 2011 through June 2012 and July - December based on planned injections and withdrawals.

MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT E

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$23,075	$28,741	
January 2011	221,728	244,853	
February	214,702	225,487	
March	193,742	203,043	
April	172,792	180,600	
May	151,843	158,489	
June	130,893	136,036	
July	109,943	112,699	
August	88,994	89,362	
September	68,044	66,025	
October	52,716	42,691	
November	49,466	43,763	
December	28,741	24,517	
Beginning and ending average	$25,908		
Thirteen month average		$119,716	$93,808

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects pro forma expense.

MONTANA-DAKOTA UTILITIES CO.
PREPAID DEMAND AND COMMODITY CHARGES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT F

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$1,086,349	$1,213,615	
January 2011	(171,300)	(52,608)	
February	(927,762)	(897,713)	
March	(1,399,781)	(1,359,423)	
April	(1,312,777)	(1,265,136)	
May	(809,527)	(757,031)	
June	(31,451)	(18,748)	
July	785,971	729,024	
August	1,615,672	1,427,013	
September	2,428,885	2,279,771	
October	2,703,035	2,444,050	
November	2,168,667	1,937,309	
December	1,213,615	911,740	
Beginning and ending average	$1,149,981		
Thirteen month average		$507,066	($642,915)

1/ Reflects actual balances December 2011 through June 2012 and July - December based on August 2012 PGA projections.

MONTANA-DAKOTA UTILITIES CO.
UNAMORTIZED GAIN(LOSS) ON DEBT
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT G

	Loss on Debt	Accumulated Deferred Income Taxes
Balance at December 31, 2010	$631,135	($260,329)
Balance at December 31, 2011	538,504	(216,338)
Average Balance	$584,820	($238,334)
2012 Amortization 1/	(14,981)	19,061
Balance at December 31, 2012	$523,523	($197,277)
Average Balance at December 31, 2012	$531,014	($206,808)
Pro Forma Adjustment	($53,806)	$31,526

1/ Reflects a reallocation of balance and current amortization.

MONTANA-DAKOTA UTILITIES CO.
PROVISION FOR PENSIONS AND BENEFITS
ACCUMULATED DEFERRED INCOME TAXES ON PENSIONS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT H

	Total	Provision for Pensions	Gas DIT on Pension
Balance at December 31, 2010	$9,558	$1,594,562	($1,585,004)
Balance at December 31, 2011	9,778,591	14,596,722	(4,818,131)
Average Balance	$4,894,074	$8,095,642	($3,201,568)
Allocated to Gas Utility 1/	$4,800,716	$4,800,716	
Allocated to Montana 2/	$422,658	$1,268,837	($846,179)

1/ Pension provision is allocated to the gas utility based on payroll expense.
2/ Allocated on Net Plant in Service.

**MONTANA-DAKOTA UTILITIES CO.
PROVISION FOR INJURIES AND DAMAGES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT I**

	Total	Provision for Injuries and Damages	Gas DIT on Injuries and Damages
Balance at December 31, 2010	($600,130)	($963,496)	$363,366
Balance at December 31, 2011	(351,375)	(568,573)	217,198
Average Balance	($475,753)	($766,035)	$290,282
Allocated to Gas Utility 1/	($257,858)	($415,191)	$157,333
Allocated to Montana 2/	($68,153)	($109,736)	$41,583

1/ Allocated on insurance expense.
2/ Allocated on Net Plant in Service.

MONTANA-DAKOTA UTILITIES CO.
DEFERRED FAS 106 BALANCE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT J

	Total	Deferred FAS 106	Deferred Inc Tax -FAS 106
Balance at December 31, 2010	$89,821	$148,226	($58,405)
Balance at December 31, 2011	66,388	109,558	(43,170)
Average Balance	$78,105	$128,892	($50,788)
Pro Forma Average Balance 1/	$246,024	$402,667	($156,643)
Pro Forma Adjustment		$273,775	($105,855)

1/ Reflects levelization of balance pursuant to Order No. 5856g in Docket No. D95.7.90.

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT N

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$770,737	$683,775	
January 2011	724,483	684,920	
February	715,446	696,451	
March	718,039	696,780	
April	718,071	711,981	
May	721,821	712,080	
June	707,803	712,141	
July	710,955	710,955	
August	711,296	711,296	
September	714,768	714,768	
October	723,118	723,118	
November	740,251	740,251	
December	683,775	683,775	
Beginning and ending average	$727,256		
13 month average		$706,330	($20,926)

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects per books 2011.

MONTANA-DAKOTA UTILITIES CO.
CAPITAL STRUCTURE
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

	Balance	Ratio	Cost	Weighted Cost
Per Books				
Long Term Debt	$280,492,390	43.316%	6.845%	2.965%
Short Term Debt 1/	1,933,973	0.299%	13.053%	0.039%
Preferred Stock	15,450,000	2.386%	4.588%	0.109%
Common Equity	349,672,199	53.999%	10.500%	5.670%
Total	$647,548,562	100.000%		8.783%
Pro Forma				
Long Term Debt	$280,485,103	39.691%	6.846%	2.717%
Short Term Debt 1/	33,568,454	4.750%	1.399%	0.066%
Preferred Stock	15,350,000	2.172%	4.583%	0.100%
Common Equity	377,270,918	53.387%	10.500%	5.606%
Total	$706,674,475	100.000%		8.489%

1/ Reflects average monthly balance.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY COMMON EQUITY
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

Description	Amount
Common Equity - 12/31/2010	$2,677,801,720
Investment in Subsidiaries	2,336,133,124
Utility Common Equity - 12/31/2010	$341,668,596
Common Equity - 12/31/2011	$2,773,706,735
Investment in Subsidiaries	2,416,030,933
Utility Common Equity - 12/31/2011	$357,675,802
Average @ 12/31/2011	$349,672,199
Common Equity - 12/31/2012	$2,813,576,698
Investment in Subsidiaries	2,416,710,665
Utility Common Equity - 12/31/2012	$396,866,033
Average @ 12/31/2012	$377,270,918

MONTANA-DAKOTA UTILITIES CO.
AVERAGE LONG-TERM DEBT
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

	Balance Outstanding	Annual Cost		Adjusted Embedded Cost
First Mortgage Bonds				
Balance at 12/31/2010	$280,000,000	$19,126,500		6.831%
Minot Air Force Base Payable	495,927	29,756		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/2010	$280,495,927	$19,199,725		6.845%
Balance at 12/31/2011	$280,000,000	$19,129,500		6.832%
Minot Air Force Base Payable	488,853	29,331		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/2011	$280,488,853	$19,202,300		6.846%
Average @ 12/31/2011	$280,492,390	$19,201,013		6.845%
Balance at 12/31/2012	280,000,000	19,129,500		6.832%
Minot Air Force Base Payable	481,352	28,881		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/12	$280,481,352	$19,201,850		6.846%
Average @ 12/31/2012	$280,485,103	$19,202,075		6.846%

1/ Page 4.

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2011

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
5.98% - Senior Note	12/15/2003	12/15/2033	5.980%	$30,000,000	$30,000,000	$262,500	0.875%	$280,668	0.936%
6.33% - Senior Note	8/24/2006	8/24/2026	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
6.04% - Senior Note	9/16/2008	9/16/2018	6.040%	100,000,000	100,000,000	362,432	0.362%	0	0.000%
6.61% - Senior Note	9/1/2009	9/30/2016	6.610%	25,000,000	25,000,000	68,319	0.273%	517,288	2.069%
6.66% - Senior Note	10/1/2009	9/30/2016	6.660%	25,000,000	25,000,000	68,319	0.273%	517,288	2.069%
Total Long-Term Debt Capital				$280,000,000	$280,000,000	$1,105,631		$11,847,253	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
5.98% - Senior Note	$29,456,832	98.189%	6.205%	$30,000,000	1,861,500	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
6.04% - Senior Note	99,637,568	99.638%	6.181%	100,000,000	6,181,000	
6.61% - Senior Note	24,414,393	97.658%	7.120%	25,000,000	1,780,000	
6.66% - Senior Note	24,414,393	97.658%	7.172%	25,000,000	1,793,000	
Total Long-Term Debt Capital	$267,047,116			$280,000,000	$19,129,500	6.832%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2012

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
5.98% - Senior Note	12/15/2003	12/15/2033	5.980%	$30,000,000	$30,000,000	$262,500	0.875%	$280,668	0.936%
6.33% - Senior Note	8/24/2006	8/24/2026	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
6.04% - Senior Note	9/16/2008	9/16/2018	6.040%	100,000,000	100,000,000	362,432	0.362%	0	0.000%
6.61% - Senior Note	9/1/2009	9/30/2016	6.610%	25,000,000	25,000,000	68,319	0.273%	517,288	2.069%
6.66% - Senior Note	10/1/2009	9/30/2016	6.660%	25,000,000	25,000,000	68,319	0.273%	517,288	2.069%
Total Long-Term Debt Capital				$280,000,000	$280,000,000	$1,105,631		$11,847,253	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
5.98% - Senior Note	$29,456,832	98.189%	6.205%	$30,000,000	1,861,500	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
6.04% - Senior Note	99,637,568	99.638%	6.181%	100,000,000	6,181,000	
6.61% - Senior Note	24,414,393	97.658%	7.120%	25,000,000	1,780,000	
6.66% - Senior Note	24,414,393	97.658%	7.172%	25,000,000	1,793,000	
Total Long-Term Debt Capital	$267,047,116			$280,000,000	$19,129,500	6.832%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

MONTANA-DAKOTA UTILITIES CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

Acct. 1890 - Unamortized Loss	Amortization
PCN Notes Loss/Unamortized Expense - 2010	$43,469
PCN Notes Loss/Unamortized Expense - 2011	43,469
PCN Notes Loss/Unamortized Expense - 2012	43,469

MONTANA-DAKOTA UTILITIES CO.
AVERAGE SHORT-TERM DEBT
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

	Balance Outstanding	Annual Cost	Average Cost
2011			
Average Balance 1/	$1,933,973	$7,331	0.379%
Amortization of Fees 2/		245,102	
Total	$1,933,973	$252,433	13.053%
Pro Forma			
Average Balance 1/	$33,568,454	$225,918	0.673%
Amortization of Fees 2/		243,715	
Total	$33,568,454	$469,633	1.399%

1/ Twelve month average balance.
2/ Negotiation and commitment fees.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE PREFERRED STOCK
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

Description	Balance Outstanding	Annual Cost	Adjusted Embedded Cost
Balance at 12/31/2010	$15,500,000	$711,425	4.590%
2011 Redemptions:			
5.1% Series	(100,000)	(5,285)	
Balance at 12/31/2011	$15,400,000	$706,140	4.585%
Average @ 12/31/2011	$15,450,000	$708,783	4.588%
2012 Redemptions:			
5.1% Series	(100,000)	(5,285)	5.285%
Balance at 12/31/2012	$15,300,000	$700,855	4.581%
Average @ 12/31/2012	$15,350,000	$703,498	4.583%

MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
DECEMBER 31, 2011

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Issuance Expense Amount	Issuance Expense % Gross Proceeds
4.5% Series	01/01/51	$105	4.5%	$100	$10,000				
4.7% Series	12/07/55	102	4.7%	100	5,000				
5.1% Series	05/23/61	100/102	5.1%	100	5,000	$25,000	0.50%	$27,452	0.549%

Description	Net Proceeds Amount (000's)	Net Proceeds Per Unit	Cost of Money 1/ 2/	Principal Outstanding	December 31, 2011 Annual Cost	December 31, 2011 Embedded Cost	Method of Offering
4.5% Series	$10,000	100.000%	4.500%	$10,000,000	$450,000		Public
4.7% Series	5,000	100.000%	4.700%	5,000,000	235,000		Public
5.1% Series	4,948	98.951%	5.285%	400,000	21,140		Private
Total				$15,400,000	$706,140	4.585%	

1/ Yield to maturity based upon the life, net proceeds, and quarterly compounding of the stated dividend rate of each issue.
2/ 4.5% Series and 4.7% Series issue expense fully recovered.

Docket No. ____
Rule 38.5.148
Statement F

MONTANA-DAKOTA UTILITIES CO.
PREFERRED STOCK CAPITAL
DECEMBER 31, 2012

Description	Date of Issuance	Call (Redemption) Price	Dividend Rate	Par Value of Issue	Gross Proceeds (000's)	Underwriters' Commission		Issuance Expense	
						Amount	% Gross Proceeds	Amount	% Gross Proceeds
4.5% Series	01/01/51	$105	4.5%	$100	$10,000				
4.7% Series	12/07/55	102	4.7%	100	5,000				
5.1% Series	05/23/61	100/102	5.1%	100	5,000	$25,000	0.50%	$27,452	0.549%

Description	Net Proceeds		Cost of Money 1/ 2/	Principal Outstanding	December 31, 2012		Method of Offering
	Amount (000's)	Per Unit			Annual Cost	Embedded Cost	
4.5% Series	$10,000	100.000%	4.500%	$10,000,000	$450,000		Public
4.7% Series	5,000	100.000%	4.700%	5,000,000	235,000		Public
5.1% Series	4,948	98.951%	5.285%	300,000	15,855		Private
Total				$15,300,000	$700,855	4.581%	

1/ Yield to maturity based upon the life, net proceeds, and quarterly compounding of the stated dividend rate of each issue.
2/ 4.5% Series and 4.7% Series issue expense fully recovered.

MDU RESOURCES GROUP INC.
EQUITY (COMMON STOCK) ISSUANCE - 2007 - 2011

	Acquisition			Equity Draw Down			Employee Stock Exercise/Awards 1/			
Period	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
Beginning Balance										181,557,543
Jan-07							121,103	2,820,606		181,678,646
Feb-07							347,035	5,537,785		182,025,681
Mar-07	83,097	1,784,011					210,663	3,299,650		182,319,441
Apr-07							51,795	678,917		182,371,236
May-07							38,298	500,831		182,409,534
Jun-07	1,295	30,405					5,200	67,393		182,416,029
Jul-07	201,572	5,219,830					33,682	439,816		182,651,283
Aug-07	248,567	5,823,459					7,396	96,358		182,907,246
Sep-07							7,523	93,655		182,914,769
Oct-07							12,072	147,679		182,926,841
Nov-07							3,276	37,390		182,930,117
Dec-07							16,411	206,363		182,946,528
Jan-08							41,717	520,481		182,988,245
Feb-08	73,760	1,715,667					268,120	(2,060,313)		183,330,125
Mar-08							6,747	75,974		183,336,872
Apr-08							71,614	212,329		183,408,486
May-08	89,312	2,447,259					90,146	1,263,286		183,587,944
Jun-08	44,328	914,001					73,964	969,247		183,706,236
Jul-08							49,448	651,911		183,755,684
Aug-08							9,513	125,759		183,765,197
Sep-08							4,950	65,439		183,770,147
Oct-08							430,236	9,048,013		184,200,383
Nov-08							4,450	55,870		184,204,833
Dec-08							3,450	45,609		184,208,283
Jan-09							2,200	29,083		184,210,483
Feb-09	5,801	158,955					108,631	(813,970)		184,324,915
Mar-09	171,050	2,345,453					3,469	41,643		184,499,434
Apr-09							450	5,949		184,499,884
May-09							3,725	49,242		184,503,609
Jun-09							4,500	59,490		184,508,109
Jul-09							104,600	1,973,019		184,612,709
Aug-09	575,728	10,303,106					976,800	19,685,930		186,165,237
Sep-09							1,507,800	29,485,651		187,673,037

MDU RESOURCES GROUP INC.
EQUITY (COMMON STOCK) ISSUANCE - 2007 - 2011

	Acquisition			Equity Draw Down			Employee Stock Exercise/Awards 1/			
Period	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares	Dollars	Flotation Costs	Shares Outstanding
Oct-09							615,600	12,278,369		188,288,637
Nov-09							42,651	35,694		188,331,288
Dec-09							57,977	766,335		188,389,265
Jan-10							12,600	166,552		188,401,865
Feb-10	56,149	1,017,372					134,929	(902,793)		188,592,943
Mar-10	29,355	547,671					33,714	760,088		188,656,012
Apr-10							13,410	177,265		188,669,422
May-10							450	306,848		188,669,872
Jun-10							2,660	35,164		188,672,532
Jul-10							34,205	452,124		188,706,737
Aug-10							14,050	389,315		188,720,787
Sep-10							11,413	150,874		188,732,200
Oct-10							64,674	854,889		188,796,874
Nov-10							40,416	534,235		188,837,290
Dec-10							64,089	847,207		188,901,379
Jan-11							265,572	3,512,715		189,166,951
Feb-11	7,515	140,976					158,019	2,230,605		189,332,485
Mar-11										189,332,485
Apr-11										189,332,485
May-11										189,332,485
Jun-11										189,332,485
Jul-11										189,332,485
Aug-11										189,332,485
Sep-11										189,332,485
Oct-11										189,332,485
Nov-11										189,332,485
Dec-11										189,332,485
Totals	1,587,529	32,448,167	-	-	-	-	6,187,413	98,011,569	-	

1/ Includes 401(k), Dribble and DRIP purchases when applicable.

MDU RESOURCES GROUP, INC.
STOCK DIVIDENDS, STOCK SPLITS OR CHANGES IN PAR OR STATED VALUE
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2011

MDU Resources Group, Inc. did not issue shares in connection with a stock split or stock dividend during the five years ended December 2011.

MDU RESOURCES GROUP, INC.
COMMON STOCK DATA
FOR THE FIVE YEARS ENDED DECEMBER 31, 2011

	Avg. Number of Shares Outstanding (000's)	Annual Diluted Earnings (per share) 1/	Annual Dividends (per share)	Dividend/ Earnings Ratio	Average Market Price 2/	Price/ Earnings Ratio	Dividend/ Price Ratio
Year Ended December 31:							
2007	182,902	2.36	0.5600	24%	27.72	11.7	2.0%
2008	183,807	1.59	0.6000	38%	27.08	17.0	2.2%
2009	185,175	(0.67)	0.6225	N/A	19.26	N/A	3.2%
2010	188,137	1.27	0.6350	50%	20.31	16.0	3.1%
2011	188,763	1.12	0.6550	58%	21.41	19.1	3.1%
Twelve Months:							
January 2011	188,189	1.28	0.6350	50%	20.12	15.7	3.2%
February	188,251	1.29	0.6350	49%	20.16	15.6	3.2%
March	188,311	1.28	0.6400	50%	20.21	15.8	3.2%
April	188,366	1.25	0.6400	51%	20.31	16.2	3.2%
May	188,422	1.24	0.6400	52%	20.63	16.6	3.1%
June	188,477	1.26	0.6450	51%	20.98	16.6	3.1%
July	188,532	1.24	0.6450	52%	21.24	17.1	3.0%
August	188,584	1.20	0.6450	54%	21.32	17.8	3.0%
September	188,634	1.27	0.6500	51%	21.36	16.8	3.0%
October	188,681	1.31	0.6500	50%	21.32	16.3	3.0%
November	188,724	1.22	0.6500	53%	21.34	17.5	3.0%
December	188,763	1.12	0.6550	58%	21.41	19.1	3.1%

1/ Earnings per share amounts reflect a $84.2 million after tax and $384.4 million after tax noncash write-down of natural gas and oil properties in 2008 and 2009, respectively.
2/ The average market price is based on monthly high and low for the year.

MONTANA-DAKOTA UTILITIES CO.
REACQUISITION OF BONDS OR PREFERRED STOCK
FOR THE FIVE-YEAR PERIOD ENDING DECEMBER 31, 2011

First Mortgage Bonds

Retired April 1, 2007
- $6,500,000, 8.25% Secured Medium-Term Note due April 1, 2007

Retired October 1, 2008
- $15,000,000, 5.83% Secured Medium-Term Note due October 1, 2008

Retired October 1, 2009
- $1,000,000, 6.71% Secured Medium-Term Note due October 1, 2009

Retired November 17, 2009
- $4,500,000, 8.6% Secured Medium-Term Note due April 1, 2012

Preferred Stock

	Principal Amount	Reacquisition Cost	Gain or (Loss)
5.1% Preferred Stock	$500,000	$500,000	$0

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

	Montana	Pro Forma Adjustments	Pro Forma
Production	$188,558	1,322	$189,880
Cost of Gas	52,735,031	(13,880,459)	38,854,572
Other Gas Supply	73,609	2,491	76,100
Distribution	4,322,878	149,824	4,472,702
Customer Accounts	1,948,083	33,060	1,981,143
Customer Service & Infor.	89,100	2,640	91,740
Sales	119,573	3,837	123,410
Administrative and General	4,127,510	54,593	4,182,103
Total Operation and Maintenance Expenses	$63,604,342	($13,632,692)	$49,971,650

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Account No.	Description	Per Books	Pro Forma Adjustments	Pro Forma
	Production			
754	Field Compressor Station	$188,558		
	Total Production Expenses	$188,558	$1,322	$189,880
	Other Gas Supply Expenses			
804	Natural Gas City Gate Purchases	$54,043,984		
805.1	Purchased Gas Cost Adjustments	52,394		
808.1	Gas Withdrawn from Storage	11,534,090		
808.2	Gas Delivered to Storage	(12,895,437)		
813	Other Gas Supply Expenses	73,609		
	Total Other Gas Supply Expenses	$52,808,640	($13,877,968)	$38,930,672
	Distribution Expenses			
	Operation			
870	Supervision and Engineering	$514,850		
871	Distribution Load Dispatching	74,482		
874	Mains and Services	1,138,366		
875	Measuring & Reg. Station Exp. - General	34,815		
876	Measuring & Reg. Station Exp. - Industrial	14,521		
878	Meters and House Regulators	267,551		
879	Customer Installations	538,992		
880	Other Expenses	832,223		
881	Rents	33,379		
	Total Operation Expenses	$3,449,179		
	Maintenance			
885	Supervision & Engineering	$130,671		
886	Structures & Improvements	1,179		
887	Mains	138,093		
889	Measuring & Reg. Station Exp. - General	28,158		
890	Measuring & Reg. Station Exp. - Industrial	15,721		
892	Services	155,111		
893	Meters and House Regulators	284,028		
894	Other Equipment	120,738		
	Total Maintenance Expenses	$873,699		
	Total Distribution Expenses	$4,322,878	$149,824	$4,472,702

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Account No.	Description	Per Books	Pro Forma Adjustments	Pro Forma
	Customer Accounts Expenses			
	Operation			
901	Supervision	$96,853		
902	Meter Reading Expenses	230,640		
903	Customer Records and Collection Exp.	1,376,127		
904	Uncollectible Accounts	173,361		
905	Misc. Customer Accounts Expenses	71,102		
	Total Customer Accounts Expenses	$1,948,083	$33,060	$1,981,143
	Customer Service & Information Expenses			
	Operation			
907	Supervision	$28,529		
908	Customer Assistance Expenses	11,125		
909	Informational and Instructional Expenses	29,421		
910	Misc. Customer Service & Info. Exp.	20,025		
	Total Customer Service & Info. Exp.	$89,100	$2,640	$91,740
	Sales Expenses			
	Operation			
911	Supervision	$22,826		
912	Demonstrating and Selling Expenses	72,731		
913	Advertising Expenses	12,258		
916	Misc. Sales Expenses	11,758		
	Total Sales Expenses	$119,573	$3,837	$123,410
	Administrative & General Expenses			
	Operation			
920	Administrative and General Salaries	$956,138		
921	Office Supplies and Expenses	548,659		
923	Outside Services Employed	123,948		
924	Property Insurance	80,637		
925	Injuries and Damages	263,669		
926	Employee Pensions and Benefits	1,837,398		
928	Regulatory Commission Expenses	1,742		
930	Miscellaneous General Expenses	97,390		
931	Rents	115,735		
	Total Operation Expenses	$4,025,316		
	Maintenance			
935	Maintenance of General Plant	$102,194		
	Total Maintenance Expenses	102,194		
	Total Administrative & General Expenses	$4,127,510	$54,593	$4,182,103
	Total Operation & Maintenance Expenses	$63,604,342	($13,632,692)	$49,971,650

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA

Function	Total	Cost of Gas	Labor	Benefits	Vehicles & Work Equipment	Company Consumption	Uncollectible Accounts	Advertising
Cost of Gas	$38,854,572	$38,854,572						
Other Gas Supply	76,100		$55,136		$275			
Production	189,880		29,483		928			
Distribution	4,472,702		3,551,214		404,255	$32,509	$634	
Customer Accounting	1,981,143		1,105,295		50,267	9,145	158,458	
Customer Service & Information	91,740		58,456		369			
Sales	123,410		90,832		2,043	1,618		
Administrative and General	4,182,103		1,069,653	$1,690,918	11,942	24,157		$28,527
Total Other O&M	11,117,078	0	5,960,069	1,690,918	470,079	67,429	159,092	28,527
Total O&M	$49,971,650	$38,854,572	$5,960,069	$1,690,918	$470,079	$67,429	$159,092	$28,527
Adjustment No.		5	6	7	8	9	10	11
Page No.		3	4	5	6	7	8	9

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA

Function	Insurance	Industry Dues	Regulatory Commission Expense	All Other O&M
Cost of Gas				
Other Gas Supply				$20,689
Production				159,469
Distribution				484,090
Customer Accounting				657,978
Customer Service & Information				32,915
Sales				28,917
Administrative and General	$271,973	$38,032	$110,042	936,859
Total Other O&M	271,973	38,032	110,042	2,320,917
Total O&M	$271,973	$38,032	$110,042	$2,320,917
Adjustment No.	12	13	14	
Page No.	10	11	12	

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS
GAS UTILITY - MONTANA
ADJUSTMENT NO. 5

	Pro Forma Dk Sales 1/	Dk Adjusted for Distribution Losses 2/	Commodity Charge 3/	Pro Forma Cost of Gas
Residential	6,097,461	6,141,681	$3.829	$23,516,497
Firm General Service	3,813,826	3,841,485	3.829	14,709,046
Small Interruptible	218,586	220,171	2.857	629,029
Large Interruptible	0	0	2.857	0
Total	10,129,873	10,203,337		$38,854,572
Per Books Cost of Gas				52,735,031
Pro Forma Adjustment				($13,880,459)

1/ Rule 38.5.164, Statement H, page 2.
2/ Distribution loss factor of .72%.
3/ August 2012 PGA adjusted to reflect annual commodity costs.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 6

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Other Gas Supply	$183,219	$52,641	$55,136	$2,495
Production	97,971	28,149	29,483	1,334
Distribution	12,308,950	3,390,504	3,551,214	160,710
Customer Accounting	3,355,405	1,055,275	1,105,295	50,020
Customer Service	279,619	55,811	58,456	2,645
Sales	297,894	86,721	90,832	4,111
A&G	3,528,635	1,021,246	1,069,653	48,407
Total	$20,051,693	$5,690,347	$5,960,069	$269,722

1/ Reflects a 4.74% increase made up of a 2.5% increase for non-union employees and 3.0% increase for union employees. Also includes the three-year amortization of severance pay recorded in 2009.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 7

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Medical/Dental	$2,117,808	$623,431	$628,980	$5,549
Pension expense	514,314	155,387	(64,455)	(219,842)
Post-retirement	453,151	152,499	384,206	231,707
401-K	2,145,671	605,091	689,804	84,713
Workers compensation	114,735	50,015	52,383	2,368
Supplemental Insurance	617,368	179,996	0	(179,996)
Total	$5,963,047	$1,766,419	$1,690,918	($75,501)

1/ Reflects an increase of 0.89% to medical and dental, a decrease of 141.48% to Pension expense an increase of 151.94% to Post-retirement expense, an increase of 14% to 401-K expense. Workers Compensation expense is based on the ratio of worker's compensation to pro forma labor expense and Supplemental Insurance was eliminated from benefits expense.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
VEHICLES AND WORK EQUIPMENT
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 8

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Other Gas Supply	$970	$279	$275	($4)
Production	$3,271	940	928	(12)
Distribution	1,379,130	410,016	404,255	(5,761)
Customer Accounting	137,048	50,998	50,267	(731)
Customer Service	7,549	374	369	(5)
Sales	9,728	2,073	2,043	(30)
A&G	44,626	12,115	11,942	(173)
Total	$1,582,322	$476,795	$470,079	($6,716)

1/ Based on pro forma plant and proposed depreciation rates.

MONTANA-DAKOTA UTILITIES CO.
COMPANY CONSUMPTION
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 9

	Per Books - Total			Pro Forma
	Total Utility	Montana	Pro Forma	Adjustment
Distribution	$210,890	$37,574	$32,509	($5,065)
Customer Accounting	59,780	10,471	9,145	(1,326)
Sales	13,488	1,862	1,618	(244)
A&G	87,948	25,642	24,157	(1,485)
Total	$372,106	$75,549	$67,429	($8,120)

	Per Books - Electric			Pro Forma
	Electric Utility	Montana	Pro Forma	Adjustment
Distribution	$72,800	$13,591	$13,591	$0
Customer Accounting	27,758	4,193	4,193	0
Sales	6,025	705	705	0
A&G	63,836	18,612	18,612	0
Total Electric	$170,419	$37,101	$37,101	$0

	Per Books - Gas			Pro Forma
	Gas Utility	Montana	Pro Forma 2/	Adjustment
Distribution	$138,090	$23,983	$18,918	($5,065)
Customer Accounting	32,022	6,278	4,952	(1,326)
Sales	7,463	1,157	913	(244)
A&G	24,112	7,030	5,545	(1,485)
Total Gas	$201,687	$38,448	$30,328	($8,120)

2/ Reflects a 21.12% decrease to reflect annualized firm sales revenue at current rates.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
UNCOLLECTIBLE ACCOUNTS
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 10

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Distribution	$580	$694	$634	($60)
Customer Accounting	591,673	173,361	158,458	(14,903)
Total	$592,253	$174,055	$159,092	($14,963)

1/ Based on 5 year average of write-offs to revenues applied to pro forma revenues.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 11

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Informational	$105,127	$29,421	$28,527	($894)
Promotional	59,631	12,258	0	(12,258)
Institutional	92,168	18,504	0	(18,504)
Total	$256,926	$60,183	$28,527	($31,656)

1/ Eliminates promotional and institutional advertising expenses and informational expenses not applicable to Montana gas operations.

MONTANA-DAKOTA UTILITIES CO.
INSURANCE EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 12

A&G Expense for Insurance	Total Company Per Books	Montana Per Books	Montana Pro Forma 1/	Pro Forma Adjustment
Director's & Officer's Liability Insurance	$71,660	$18,256	$16,710	($1,546)
Excess Liability				
Fiduciary & Employee Benefits Liability	27,454	6,994	6,826	(168)
Public Liab. & Property Ins. Damage of Others	597,609	152,247	139,860	(12,387)
All Risk	313,900	79,969	107,764	27,795
Blanket Crime	2,620	668	705	37
Special Contingency			108	108
	$1,013,243	$258,134	$271,973	$13,839

1/ Adjusted to reflect insurance expense at current levels.

MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 13

	Per Books Montana	Pro Forma		Pro Forma Adjustment
American Gas Association 1/	$20,413	$18,860	2/	($1,553)
Chamber of Commerce-Baker 3/	50	30		(20)
Chamber of Commerce-Billings 3/	2,274	1,500	2/	(774)
Chamber of Commerce-Glasgow 3/	145	87	2/	(58)
Chamber of Commerce-Glendive 3/	134	80		(54)
Chamber of Commerce-Hardin 3/	227	150	2/	(77)
Chamber of Commerce-Laurel 2/	464	306	2/	(158)
Chamber of Commerce-Malta 3/	200	204	2/	4
Chamber of Commerce-Prairie County 3/	21	13		(8)
Chamber of Commerce-Sidney 3/	242	145		(97)
Chamber of Commerce-Wibaux 3/	20	12		(8)
Chamber of Commerce-Wolf Point 3/	460	276	2/	(184)
Chamber of Commerce-Miles City 3/	302	181		(121)
Home Builders Association of Billings	346	228	2/	(118)
Montana Economic Developers Association	25	25		0
Richland Economic Development	950	950		0
Dawson County Economic Development	760	760		0
Big Sky Economic Development	0	2,500	2/	2,500
Bureau of Business and Economic Development	2,280	2,280		0
Metrapark Foundation	910	910		0
Miles City Area Economic Development Council	161	161		0
Midwest Region Gas Task Force	255	255		0
Midwest Energy Association	7,846	7,626	2/	(220)
Montana Water Resources Association	135	135		0
United Telecom Council	334	334		0
Custer County Art Center	24	24		0
Other	6,192	0		(6,192)
Total Industry Dues	$45,170	$38,032		($7,138)

1/ Lobbying portion excluded from amounts recorded.
2/ Pro Forma reflects actual 2012 amount.
3/ Pro Forma reflects the elimination of lobbying expenses as a percentage of annual dues.

MONTANA-DAKOTA UTILITIES CO.
REGULATORY COMMISSION EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 14

	Montana		Pro Forma
	Per Books	ProForma 1/	Adjustment
A & G	$1,742	$110,042	$108,300

1/ Reflects 3 year amortization of rate case expense.

MONTANA-DAKOTA UTILITIES CO.
OTHER O&M
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Per Books Other O & M	Items Adjusted Individually	Other O & M
Other Gas Supply	$73,609	$52,920	$20,689
Production	188,558	29,089	159,469
Distribution	4,322,878	3,838,788	484,090
Customer Accounting	1,948,083	1,290,105	657,978
Customer Service & Information	89,100	56,185	32,915
Sales	119,573	90,656	28,917
Administrative and General	4,127,510	3,190,651	936,859
Total Other O&M	$10,869,311	$8,548,394	$2,320,917

MONTANA-DAKOTA UTILITIES CO.
ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Per Books	Cost of Gas	Labor	Benefits	Vehicles & Work Equipment	Company Consumption	Uncollectible Accounts	Advertising
Cost of Gas	$52,735,031	$52,735,031						
Other Gas Supply	73,609		$52,641		$279			
Production	188,558		28,149		940			
Distribution	4,322,878		3,390,504		410,016	$37,574	$694	
Customer Accounting	1,948,083		1,055,275		50,998	10,471	173,361	
Customer Service & Information	89,100		55,811		374			
Sales	119,573		86,721		2,073	1,862		
Administrative and General	4,127,510		1,021,246	$1,766,419	12,115	25,642		$60,183
Total Other O&M	10,869,311	0	5,690,347	1,766,419	476,795	75,549	174,055	60,183
Total O&M	$63,604,342	$52,735,031	$5,690,347	$1,766,419	$476,795	$75,549	$174,055	$60,183

MONTANA-DAKOTA UTILITIES CO.
ITEMS ADJUSTED INDIVIDUALLY
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Insurance	Industry Dues	Regulatory Commission Expense	Total items adjusted individually	All Other O&M
Cost of Gas				$52,735,031	
Other Gas Supply				52,920	$20,689
Production				29,089	159,469
Distribution				3,838,788	484,090
Customer Accounting				1,290,105	657,978
Customer Service & Information				56,185	32,915
Sales				90,656	28,917
Administrative and General	$258,134	$45,170	$1,742	3,190,651	936,859
Total Other O&M	258,134	45,170	1,742	8,548,394	2,320,917
Total O&M	$258,134	$45,170	$1,742	$61,283,425	$2,320,917

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS – GAS UTILITY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

The cost of gas for the twelve months ending December 31, 2011 is on Rule 38.8.156, Statement G, page 1. The adjusted cost of gas is on Rule 38.5.157, Statement G, page 3.

MONTANA-DAKOTA UTILITIES CO.
ADMINISTRATIVE AND GENERAL
OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Administrative and general operation and maintenance expenses by account are shown on Rule 38.5.156, Statement G, page 3. See Rule 38.5.159, Statement G, page 2 for advertising expense detail. See Rule 38.5.160 for details on intercompany transactions.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Gas Utility	Montana
Informational - Acct. 909		
5711 Radio	$14,796	$2,675
5712 Newspaper	0	0
5713 Television	15,410	2,100
5715 Other	74,921	24,646
Total	105,127	29,421
Promotional - Acct. 913		
5711 Radio	$9,441	$0
5712 Newspaper	2,406	0
5713 Television	0	0
5715 Other	47,784	12,258
Total	59,631	12,258
Institutional - Acct. 930.1		
5711 Radio	$12,468	$44
5712 Newspaper	4,888	750
5713 Television	311	14
5715 Other	74,501	17,696
Total	92,168	18,504
Total Advertising	$256,926	$60,183
Summary		
Radio	36,705	2,719
Newspaper	7,294	750
Television	15,721	2,114
Other	197,206	54,600
Total	$256,926	$60,183

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Materials		$2,743		$2,039
3		Office Expense		2,524		643
4		Travel		168		
5						
6		Capital	Actual Costs Incurred			
7		Contract Services		2,638		2,638
8		Materials		10,592		9,718
9						
10		Other				
11		Balance Sheet Accts	Actual Costs Incurred	335,556		
12		MDU Resources Cost Centers		8,031		
13		Non Utility		856		
14						
15		Total Knife River Corporation Operating Revenues for the Year 2011			$1,510,010,000	
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$363,108	0.0240%	$15,038

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Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$54,426,155		$16,901,243
3						
4		Expense	Actual Costs Incurred			
5		Contract Services		20,955		12,070
6		Materials		10,580		6,951
7		Miscellaneous		8,631		2,178
8						
9		Capital	Actual Costs Incurred			
10		Contract Services		201,337		54,606
11		Materials		38,504		6,303
12						
13						
14		Other	Actual Costs Incurred			
15		Auto Clearing		14,731		
16		Balance sheet accounts		1,028,253		
17		Non Utility		11,014		
18		MDU Resources Cost Centers		12,474		
19						
20		Total WBI Holdings, Inc. Operating Revenues for the Year 2011			$731,929,000	
21		Excludes Intersegment Eliminations				
22						
23						
24	**TOTAL**	**Grand Total Affiliate Transactions**		$55,772,634	7.6200%	$16,983,351

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU CONSTRUCTION**	Expense	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Contract Services		$4,482		$4,126
3						
4		Capital				
5		Contract Services	Actual Costs Incurred	147,095		147,095
6		Materials		269		88
7						
8		Other	Actual Costs Incurred			
9		MDU Resources Cost Centers		11,601		
10		Auto Clearing		88		
11		Non Utility		1,980		
12						
13						
14						
15		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2011			$854,389,000	
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$165,515	0.0194%	$151,309

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Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	* Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$84,989		$21,652
3		Corporate Aircraft	Actual Costs Incurred	25,886		4,978
4		Office Expense		170,410		43,413
5		Rent		110,535		28,160
6		Other		21		
7						
8		Capital	Actual Costs Incurred			
9		Corporate Aircraft		543		158
10		Materials		4,195		1,112
11		Other		1,115		330
12						
13		Other	Actual Costs Incurred			
14		MDU Resources Cost Centers		348,255		
15		Balance Sheet Accts		2,100,089		
16		Clearing Accounts		515,238		
17		Non Utility		3,179		
18						
19		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2011			$11,446,000	
20		Excludes Intersegment Eliminations				
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$3,364,455	29.3942%	$99,803

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Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU ENERGY CAPITAL**	Expense	Actual Costs Incurred			
2		Contract Services		$40,624		$11,773
3		Cost of Service		14,681		3,740
4		Materials		3,463		882
5		Office Expenses		55,543		16,842
6		Other		3,440		982
7		Travel				
8						
9						
10		Capital	Actual Costs Incurred			
11		Contract Services		18,427		4,764
12		Materials		17,881		4,772
13		Other		339		84
14						
15						
16						
17		Other Transactions/Reimbursements	Actual Costs Incurred			
18		MDU Resources Cost Centers		2,529		
19		Auto Clearing		3,248		
20		Customer Advances		8,300		
21		Subsidiary Receivables		1,897		
22		Miscellaneous		1,160		
23		Non Utility		49,416		
24						
25		Total MDU Energy Capital Operating Revenues for the Year 2011			$614,601,000	
26		Grand Total Affiliate Transactions				
27						
28	**TOTAL**	**Grand Total Affiliate Transactions**		$220,948	0.0359%	$43,839

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**KNIFE RIVER**	MDU RESOURCES GROUP, INC.				
2	**CORPORATION**	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$44,907		
4		Advertising	Costs Incurred	98,387		
5		Air Service		25,601		
6		Automobile		5,049		
7		Bank Services		91,555		
8		Corporate Aircraft		29,113		
9		Consultant Fees		153,734		
10		Contract Services		893,038		
11		Computer Rental		1,395		
12		Directors Expenses		503,601		
13		Employee Benefits		43,758		
14		Employee Meeting		35,099		
15		Employee Reimbursable Expense		49,429		
16		Express Mail		3		
17		Insurance		303,887		
18		Legal Retainers & Fees		285,037		
19		Moving Allowance		1,310		
20		Meal Allowance		620		
21		Cash Donations		19,242		
22		Meals & Entertainment		29,833		
23		Industry Dues & Licenses		39,030		
24		Office Expenses		26,346		
25		Supplemental Insurance		723,477		
26		Permits & Filing Fees		7,565		
27		Postage		5,196		
28		Payroll		5,337,349		
29		Reimbursements		13,760		
30		Reference Materials		46,856		
31		Rental		524		
32		Seminars & Meeting Registrations		22,603		
33		Software Maintenance		207,342		
34		Telephone/Cell Expenses		113,555		
35		Training		16,250		
36		**Total MDU Resources Group, Inc.**		$9,174,451	0.6289%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**KNIFE RIVER**	MONTANA-DAKOTA UTILITIES CO.				
2	**CORPORATION**	Office Services	* General Office Complex and Office			
3		Office Expenses	Supplies Cost of Service Allocation	$4		
4			Factors			
5						
6		Other Direct Charges	Actual Costs Incurred			
7		Vehicle Maintenance		4,314		
8		Communications		20,393		
9		Employee Discounts		40,446		
10		Dues, Permits, and Filing Fees		355		
11		Electric Consumption		57,782		
12		Gas Consumption		51,213		$28,200
13		Bank Fees		28,589		
14		Computer/Software Support		1,365,606		
15		Office Expense		2,219		
16		Cost of Service		334,608		79,753
17		Audit Costs		688,312		
18		Auto		8,435		
19		Travel		35,278		
20		Employee Benefits		(5,372)		
21		Contract Services		62,360		
22						
23		**Total Montana-Dakota Utilities Co.**		$2,694,542	0.1847%	$107,953
24						
25		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
26		Federal & State Tax Liability Payments		$22,645,083		
27		Miscellaneous Reimbursements		(216,273)		
28						
29		**Total Other Transactions/Reimbursements**		$22,428,810	1.5374%	
30						
31		**Grand Total Affiliate Transactions**		$34,297,803	2.3509%	$107,953
32						
33		**Total Knife River Corporation Operating Expenses for 2011-Excludes Intersegment Eliminations**			$1,458,918,000	
34						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

KNIFE RIVER CORPORATION

* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**WBI HOLDINGS, INC.**	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$59,099		
4		Advertising	Studies and/or Actual Costs	131,894		
5		Air Service	Incurred	23,905		
6		Automobile		11,187		
7		Bank Services		119,991		
8		Corporate Aircraft		36,567		
9		Consultant Fees		201,340		
10		Contract Services		374,599		
11		Computer Rental		1,810		
12		Directors Expenses		659,398		
13		Employee Benefits		58,151		
14		Employee Meeting		44,698		
15		Employee Reimbursable Expense		52,518		
16		Express Mail		4		
17		Insurance		429,420		
18		Legal Retainers & Fees		371,917		
19		Meal Allowance		814		
20		Cash Donations		24,561		
21		Meals & Entertainment		39,542		
22		Moving Expense		1,660		
23		Industry Dues & Licenses		50,099		
24		Office Expenses		22,185		
25		Supplemental Insurance		973,081		
26		Permits & Filing Fees		9,573		
27		Postage		6,844		
28		Payroll		6,062,394		
29		Reimbursements		(1,026)		
30		Reference Materials		61,961		
31		Rental		2,064		
32		Seminars & Meeting Registrations		28,147		
33		Software Maintenance		157,640		
34		Telephone/Cell Expenses		67,497		
35		Training Material		15,207		
36		**Total MDU Resources Group, Inc.**		$10,098,741	1.8269%	

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**WBI HOLDINGS, INC.**	MONTANA-DAKOTA UTILITIES CO.				
2		Other Departments	* Various Corporate Overhead			
3		Expense	Allocation Factors, Cost of			
4		Payroll	Service Factors, Time	$6,132		
5		Automobile	Studies and /or Actual Costs	2,044		
6		Materials		2,004		
7		Office Expenses		5		
8		Miscellaneous		1,542		
9						
10		Transportation Department	* Various Corporate Overhead			
11		Clearing Accounts	Allocation Factors, Time Studies			
12		Office Expenses	and/or Actual Costs Incurred	136		
13						
14		Other Direct Charges	Actual Costs Incurred			
15		Utility/Merchandise Discounts		35,791		
16		Audit Costs		391,697		
17		Contract Services		484,906		
18		Auto		3,598		
19		Vehicle Maintenance		10,730		
20		Dues, Permits, and Filing Fees		4,078		
21		Misc Employee Benefits		51,397		
22		Computer/Software Support		373,935		
23		Electric Consumption		1,714,371		$1,385,181
24		Gas Consumption		45,342		31,063
25		Cost of Service		225,943		53,853
26		Region Billings		17,272		
27		Legal Fees		7,135		
28		Travel		10,334		
29		Communication Services		11,112		
30		Office Expense		14,158		
31		Bank Fees		13,951		
32		Training Registration		14,046		
33						
34		**Total Montana-Dakota Utilities Co.**		$3,441,659	0.6226%	$1,470,097
35						

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price		(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**WBI HOLDINGS, INC.**					
2						
3						
4						
5		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
6		Federal & State Tax Liability Payments		($6,379,517)		
7		Miscellaneous Reimbursements		(88,077)		
8		**Total Other Transactions/Reimbursements**		($6,467,594)	-1.1700%	
9						
10		**Grand Total Affiliate Transactions**		$7,072,806	1.2795%	$1,470,097
11						
12						
13						
14		**Total WBI Holdings Operating Expenses for 2011 - Excludes Intersegment Eliminations**			$552,774,000	
15						

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU CONSTRUCTION**	MDU RESOURCES GROUP, INC.				
2	**SERVICES GROUP INC**	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$9,892		
4		Advertising	Studies and/or Actual Costs	9,944		
5		Air Service	Incurred	8,400		
6		Automobile		955		
7		Bank Services		20,141		
8		Corporate Aircraft		6,175		
9		Consultant Fees		33,811		
10		Contract Services		53,606		
11		Computer Rental		306		
12		Directors Expenses		110,749		
13		Employee Benefits		9,555		
14		Employee Meeting		7,648		
15		Employee Reimbursable Expense		10,860		
16		Express Mail		1		
17		Insurance		73,538		
18		Legal Retainers & Fees		62,611		
19		Moving Allowance		285		
20		Meal Allowance		136		
21		Cash Donations		4,196		
22		Meals & Entertainment		7,051		
23		Industry Dues & Licenses		8,383		
24		Office Expenses		3,348		
25		Supplemental Insurance		158,990		
26		Permits & Filing Fees		1,654		
27		Postage		1,145		
28		Payroll		1,335,348		
29		Reimbursements		(614)		
30		Reference Materials		10,384		
31		Rent		114		
32		Seminars & Meeting Registrations		4,825		
33		Software Maintenance		22,675		
34		Telephone/Cell Expenses		5,990		
35		Training Material		2,298		
36		**Total MDU Resources Group, Inc.**		$1,984,400	0.2434%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU CONSTRUCTION**	MONTANA-DAKOTA UTILITIES CO.				
2	**SERVICES GROUP INC**	Intercompany Settlements	Actual Costs Incurred			
3		Legal Fees		$132,420		
4		Audit		404,844		
5		Computer/Software Support		99,951		
6		Travel		5,687		
7		Cost of Service		98,843		$23,559
8		Employee Benefits		169,680		
9		Bank Fees		64,022		
10		Dues, Permits, and Filing Fees		15,884		
11		Payroll		2,050,399		
12		Office Expense		1,633		
13		Contract Services		106,259		
14						
15		**Total Montana-Dakota Utilities Co.**		$3,149,622	0.3863%	$23,559
16						
17		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
18		Federal & State Tax Liability Payments		$12,673,832		
19		Miscellaneous Reimbursements		(161,197)		
20						
21		**Total Other Transactions/Reimbursements**		$12,512,635	1.5348%	
22						
23		**Grand Total Affiliate Transactions**		$17,646,657	2.1646%	$23,559
24						
25		**Total MDU Construction Services Group, Inc. Operating Expenses for 2011**				
26		**Excludes Intersegment Eliminations**			$815,245,000	
27						

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**CENTENNIAL ENERGY**	MONTANA-DAKOTA UTIILITIES CO.				
2	**RESOURCES**	Other Direct Charges	Actual costs incurred			
3		Audit Costs		$10,836		
4		Dues, Permits, and Filing Fees		375		
5		Bank Fees		2,296		
6						
7		Intercompany Settlements	Actual costs incurred			
8		Filing Fees		875		
9		Office Expense		243		
10						
11		**Total Montana-Dakota Utilities Co.**		$14,625	3.5934%	
12						
13		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
14		Federal & State Tax Liability Payments		($479,318)		
15		Miscellaneous Reimbursements		(4)		
16						
17		**Total Other Transactions/Reimbursements**		($479,322)	-117.7695%	
18						
19		**Grand Total Affiliate Transactions**		($464,697)	-114.1762%	
20						
21		**Total Centennial Energy Resources Operating Expenses for 2011**			$407,000	
22		**Excludes Intersegment Eliminations**				
23						

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Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**CENTENNIAL HOLDINGS**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL CORP. AND**	Direct and Intercompany Charges	Actual costs incurred			
3	**FUTURESOURCE**	Dues, Permits, and Filing Fees		$532		
4		Computer/Software Support		17,256		
5		Bank Fees		2,258		
6		Materials		163		
7		Office Expense		3,912		
8		Electric Consumption		156,212		
9		Gas Consumption		13,309		
10		Payroll		374,526		
11		Miscellaneous		86		
12						
13		**Total Montana-Dakota Utilities Co.**		$568,254	9.4473%	
14						
15		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
16		Insurance		$119		
17		Miscellaneous Reimbursements		(6,225)		
18		Federal & State Tax Liability Payments		(1,724,608)		
19						
20		**Total Other Transactions/Reimbursements**		($1,730,714)	-28.7733%	
21						
22		**Grand Total Affiliate Transactions**		($1,162,460)	-19.3260%	
23						
24		**Total CHCC Operating Expenses for 2011**			$6,015,000	
25		**Excludes Intersegment Eliminations**				
26						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MDU RESOURCES GROUP, INC.				
2	**CAPITAL** **	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$33,969		
4		Advertising	Studies and/or Actual Costs	75,711		
5		Air Service	Incurred	15,460		
6		Automobile		3,041		
7		Bank Services		69,054		
8		Corporate Aircraft		21,100		
9		Consultant Fees		115,893		
10		Contract Services		255,792		
11		Computer Rental		1,045		
12		Directors Expenses		379,581		
13		Employee Benefits		33,407		
14		Employee Meeting		25,945		
15		Employee Reimbursable Expense		28,849		
16		Express Mail		2		
17		Insurance		243,400		
18		Legal Retainers & Fees		214,315		
19		Meal Allowance		468		
20		Cash Donations		14,246		
21		Meals & Entertainment		20,766		
22		Moving Allowance		965		
23		Industry Dues & Licenses		28,872		
24		Office Expenses		13,512		
25		Supplemental Insurance		550,937		
26		Permits & Filing Fees		5,565		
27		Postage		3,931		
28		Payroll		3,809,842		
29		Reimbursements		(3,890)		
30		Reference Materials		35,612		
31		Rental		386		
32		Seminars & Meeting Registrations		16,168		
33		Software Maintenance		93,427		
34		Telephone		26,598		
35		Training Material		9,234		
36		**Total MDU Resources Group, Inc.**		$6,143,203	1.1163%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL **	Customer Service/Credit & Collections	* Various Corporate Overhead			
3		Automobile	Allocation Factors, Cost of	$573		
4		Contract Services	Service Factors, Time Studies	4,452		
5		Employee Benefits	and/or Actual Costs Incurred	171		
6		Miscellaneous		2,088		
7		Office Expense		13,667		
8		Payroll		497,035		
9		Travel		1,284		
10						
11		Executive Departments	* Various Corporate Overhead			
12		Automobile	Allocation Factors, Cost of	22		
13		Contract Services	Service Factors, Time Studies	4,000		
14		Employee Benefits	and/or Actual Costs Incurred	14,704		
15		Miscellaneous		462		
16		Office Expense		2,012		
17		Payroll		709,719		
18		Travel		42,812		
19						
20		General & Administrative	* Various Corporate Overhead			
21		Office Expense	Allocation Factors, Cost of	2		
22		Payroll	Service Factors, Time Studies	8,565		
23		Travel	and/or Actual Costs Incurred	1,037		
24						
25		Information Systems	* Various Corporate Overhead			
26		Material	Allocation Factors, Cost of	956		
27		Miscellaneous	Service Factors, Time Studies	4,531		
28		Office Expense	and/or Actual Costs Incurred	5,037		
29		Payroll		350,389		
30		Travel		5,467		
31						
32		Other Miscellaneous Departments	* Various Corporate Overhead			
33		Payroll	Allocation Factors, Cost of Service	16,641		
34		Travel	Factors, Time Studies and/or	2,878		
35			Actual Costs Incurred			

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL** **	Payroll & HR	* Various Corporate Overhead			
3		Employee Benefits	Allocation Factors, Cost of Service	6,477		
4		Payroll	Factors, Time Studies and/or	7,727		
5						
6		Other Direct Charges	Actual costs incurred			
7		Audit		108,273		
8		Bank Fees		3,254		
9		Communications		52,422		
10		Computer Equipment/Software		125,181		
11		Contract Services		92,047		
12		Employee Benefits		(14,114)		
13		Filing Fees		1,774		
14		Industry Dues		212,771		
15		Material		8,569		
16		Miscellaneous		96		
17		Travel		19,236		
18		Vehicle Maintenance		7,166		
19						
20		Intercompany Settlements				
21		O&M	Actual costs incurred			
22		Advertising		5,122		
23		Auto		247		
24		Contract Services		433,166		
25		Cost of Service		1,515,157		$361,136
26		Employee Benefits		43,592		
27		Material		32,348		
28		Miscellaneous		54,767		
29		Office Expense		211,478		
30		Payroll		8,684,075		
31		Supplemental Insurance		166,304		
32		Software Maintenance		420,773		
33		Travel		233,677		
34						
35						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**MDU ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL ****	Intercompany Settlements				
3		Other	Actual costs incurred			
4		Audit		269,000		
5		Auto O&M		35,118		
6		LTIP		5,596		
7		MII		270,554		
8		Misc		34,366		
9		Payflex		(71,604)		
10						
11		Capital	Actual costs incurred			
12		Auto		184		
13		Contract Services		100,255		
14		Materials		114,461		
15		Office Expense		7,508		
16		Payroll		154,086		
17		Software Licenses		13,775		
18		Travel		45,556		
19		Utility Group Project Allocaion		5,450,985		
20						
21		**Total Montana-Dakota Utiilities Co.**		$20,549,929	3.7341%	$361,136
22						
23		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
24		Federal & State Tax Liability Payments		($3,669,865)		
25		Miscellaneous Reimbursements		(108,096)		
26						
27		**Total Other Transactions/Reimbursements**		($3,777,961)	-0.6865%	
28						
29		**Grand Total Affiliate Transactions**		$22,915,171	4.1638%	$361,136
30						
31		**Total MDU Energy Capital Operating Expenses for 2011**			$550,337,000	
32		**Excludes Intersegment Eliminations**				
33						
34						

Docket No. ____
Rule 38.5.160
Statement G

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

MDU ENERGY CAPITAL

* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

** MDU Energy Capital is the parent company for Cascade Natural Gas Company and Intermountain Gas Company.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	**CENTENNIAL ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**HOLDING INC**					
3		Other Direct Charges	Actual costs incurred			
4		Audit Costs		$124,450		
5		Dues, Permits, and Filing Fees		125		
6		Contract Services		64,520		
7		Bank Fees		2,338		
8		Miscellaneous		55		
9						
10		**Total Montana-Dakota Utilities Co.**		$191,488		
11						
12		**Grand Total Affiliate Transactions**		$191,488		
13						
14						
15						
16						

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Per Books	Pro Forma Adjustments	Pro Forma
Sales			
Residential	$45,522,909	($9,792,993)	$35,729,916
Firm General	26,717,947	(5,461,164)	21,256,783
Small Interruptible	1,382,090	(577,308)	804,782
Large Interruptible	107,192	(107,192)	0
Unbilled Revenue	(1,240,879)	1,240,879	0
Total Sales	$72,489,259	($14,697,778)	$57,791,481
Transportation			
Small Interruptible	$619,197	($36,468)	$582,729
Large Interruptible	647,477	(98,673)	548,804
Unbilled Revenue	(13,785)	13,785	0
Total Transportation	$1,252,889	($121,356)	$1,131,533
Total Sales and Transportation	$73,742,148	($14,819,134)	$58,923,014
Other Revenue			
Misc. Service Revenue	$45,335	$0	$45,335
Rent from Property	244,709	0	244,709
Other Revenue	78,782	47,286	126,068
Total Other Revenue	$368,826	$47,286	$416,112
Total Operating Revenue	$74,110,974	($14,771,848)	$59,339,126

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Per Books		Per Books @ Current Rates		Normalized @ Current Rates		Annualized @ Current Rates	
	Dk	Revenue	Dk	Revenue	Dk	Revenue	DK	Revenue
Sales								
Residential	6,268,127	$45,522,909	6,268,127	$36,569,220	6,082,510	$35,644,290	6,097,461	$35,729,916
Firm General Service	3,814,964	26,717,947	3,814,964	21,257,139	3,781,959	21,085,183	3,813,826	21,256,783
Small Interruptible	278,445	1,382,090	278,445	1,021,471	218,586	804,782	218,586	804,782
Large Interruptible	23,609	107,192	23,609	80,712	0	0	0	0
Unbilled Revenue	0	(1,240,879)	0	0	0	0	0	0
Total Sales	10,385,145	$72,489,259	10,385,145	$58,928,542	10,083,055	$57,534,255	10,129,873	$57,791,481
Transportation								
Small Interruptible	728,209	619,197	728,209	613,831	686,293	582,729	686,293	582,729
Large Interruptible	4,614,240	647,477	4,614,240	590,446	4,197,933	548,804	4,197,933	548,804
Unbilled Revenue	0	(13,785)	0	0	0	0	0	0
Total Transportation	5,342,449	1,252,889	5,342,449	1,204,277	4,884,226	1,131,533	4,884,226	1,131,533
Total	15,727,594	$73,742,148	15,727,594	$60,132,819	14,967,281	$58,665,788	15,014,099	$58,923,014

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 1

	Per Books		Per Books @ Current Rates		
	Dk	Revenue	Dk	Revenue 1/	Adjustment
Sales					
Residential	6,268,127	$45,522,909	6,268,127	$36,569,220	($8,953,689)
Firm General Service	3,814,964	26,717,947	3,814,964	21,257,139	(5,460,808)
Small Interruptible	278,445	1,382,090	278,445	1,021,471	(360,619)
Large Interruptible	23,609	107,192	23,609	80,712	(26,480)
Unbilled Revenue	0	(1,240,879)	0	0	1,240,879
Total Sales	10,385,145	$72,489,259	10,385,145	$58,928,542	(13,560,717)
Transportation					
Small Interruptible	728,209	619,197	728,209	613,831	(5,366)
Large Interruptible	4,614,240	647,477	4,614,240	590,446	(57,031)
Unbilled Revenue	0	(13,785)	0	0	13,785
Total Transportation	5,342,449	1,252,889	5,342,449	1,204,277	(48,612)
Total	15,727,594	$73,742,148	15,727,594	$60,132,819	($13,609,329)

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 2

	Per Books @ Current Rates		Normalized Dk @ Current Rates		
	Dk	Revenue	Dk	Revenue 1/	Adjustment
Sales					
Residential	6,268,127	$36,569,220	6,082,510	$35,644,290	($924,930)
Firm General Service	3,814,964	21,257,139	3,781,959	21,085,183	(171,956)
Small Interruptible	278,445	1,021,471	218,586	804,782	(216,689)
Large Interruptible	23,609	80,712	0	0	(80,712)
Unbilled Revenue	0	0	0	0	0
Total Sales	10,385,145	$58,928,542	10,083,055	$57,534,255	(1,394,287)
Transportation					
Small Interruptible	728,209	613,831	686,293	582,729	(31,102)
Large Interruptible	4,614,240	590,446	4,197,933	548,804	(41,642)
Unbilled Revenue	0	0	0	0	0
Total Transportation	5,342,449	1,204,277	4,884,226	1,131,533	(72,744)
Total	15,727,594	$60,132,819	14,967,281	$58,665,788	($1,467,031)

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 3

	Normalized Dk @ Current Rates		Annualized Dk @ Current Rates		
	Dk	Revenue	DK	Revenue 1/	Adjustment
Sales					
Residential	6,082,510	$35,644,290	6,097,461	$35,729,916	$85,626
Firm General Service	3,781,959	21,085,183	3,813,826	21,256,783	171,600
Small Interruptible	218,586	804,782	218,586	804,782	0
Large Interruptible	0	0	0	0	0
Unbilled Revenue	0	0	0	0	0
Total Sales	10,083,055	$57,534,255	10,129,873	$57,791,481	257,226
Transportation					
Small Interruptible	686,293	582,729	686,293	582,729	0
Large Interruptible	4,197,933	548,804	4,197,933	548,804	0
Unbilled Revenue	0	0	0	0	0
Total Transportation	4,884,226	1,131,533	4,884,226	1,131,533	0
Total	14,967,281	$58,665,788	15,014,099	$58,923,014	$257,226

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
OTHER OPERATING REVENUES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 4

	Per Books	Pro Forma Adjustments	Pro Forma
Misc. Service Revenue			
Seasonal Reconnect Fee	$1,480	$0	$1,480
NSF Check Fees	28,025	0	28,025
Work for Construction of Others	10,236	0	10,236
Other Misc. Service Revenue	5,594	0	5,594
Total Misc. Service Revenue	$45,335	$0	$45,335
Rent from Property	244,709	0	244,709
Other Revenue			
Sale of Sundry Junk Material	$878	$0	$878
Sale of Operating Construct. Mat.	475	0	475
Patronage Dividends	1,912	0	1,912
Miscellaneous	39,440	0	39,440
Late Payments Revenue		45,851	45,851
Gain/(Loss) on Disposal of Property		17,770 1/	17,770
Penalty Revenue	36,077	(16,335) 2/	19,742
Total Other Revenue	$78,782	$47,286	$126,068
Total Other Operating Revenue	$368,826	$47,286	$416,112

1/ Amortization of gain/(loss) on sale of plant over five year period.
2/ Restates penalty revenue to a three year average.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - MONTANA
Pro Forma 2012

Customer Class/Rate	Pro Forma Customers 1/	Pro Forma Dk 1/	Pro Forma Revenue 1/	Total Proposed Revenue 2/	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	70,161	6,097,461	$35,729,916	$38,566,241	$2,836,325	7.9%
Firm General Service - Rates 70 & 72	8,700	3,813,826	21,256,783	21,851,209	594,426	2.8%
Small Interruptible						
Sales - Rate 71	9	218,586	804,782			
Transport - Rates 81	35	686,293	582,729			
Total Small Interruptible	44	904,879	1,387,511	1,406,672	19,161	1.4%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	5	4,197,933	548,804			
Total Large Interruptible	5	4,197,933	548,804	556,304	7,500	1.4%
Total Montana	78,910	15,014,099	$58,923,014	$62,380,426	$3,457,412	5.9%

1/ Rule 38.5.164, Statement H, Page 3.
2/ Rule 38.5.177, Statement M, Page 2.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	2011 Per Books	Pro Forma Adjustment	Pro Forma Expense 1/
Production	$101,594	$1,943	$103,537
Distribution	2,367,765	1,082,553	3,450,318
General	115,122	(4,128)	110,994
Common	315,830	804	316,634
Common - Intangible	110,987	331,132	442,119
CWIP in Service			2/
Total	$3,011,298	$1,412,304	$4,423,602

1/ See page 2.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 15

Function	2011 Per Books	Pro Forma Expense 1/	Pro Forma Adjustment
Production	$101,594	$103,537	$1,943
Distribution	2,367,765	3,450,318	1,082,553
General	115,122	110,994	(4,128)
Common	315,830	316,634	804
Common - Intangible	110,987	442,119	331,132
CWIP in Service		2/	2/
Total	$3,011,298	$4,423,602	$1,412,304
Pro Forma Adjustment to Accumulated Reserve			$4,480,069

1/ Average annual depreciation expense on pro forma plant in service, see Rule 38.5.165, Statement I, pages 3-4.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 15

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Production Plant				
333	Field Compressor Station Equip.	$3,109,209	3.33%	$103,537	$103,537
	Distribution Plant				
374.1	Land	$15,962			
374.2	Rights of Way	22,846	1.39%	$318	$318
375	Structures & Improvements	195,164	2.77%	5,406	5,406
376	Mains	29,580,663	2.97%	878,546	878,546
378	Meas. & Reg. Equip.-General	590,345	3.14%	18,537	18,537
379	Meas. & Reg. Equip.-City Gate	128,222	3.75%	4,808	4,808
380	Services	21,783,372	8.18%	1,781,880	1,781,880
381	Positive Meters	18,691,448	3.53%	659,808	659,808
383	Service Regulators	2,151,173	1.77%	38,076	38,076
385	Ind. Meas. & Reg. Station Eqpt.	187,825	3.31%	6,217	6,217
386.2	Other Property on Cust. Premise	148,673	0.27%	401	401
387.1	Cathodic Protection Equip.	1,175,058	3.21%	37,719	37,719
387.2	Other Distribution Equip.	117,422	0.99%	1,162	1,162
	Total Distribution Plant	$74,788,173		$3,432,878	$3,432,878
	General Plant				
389	Land	$7,131			
390	Structures and Improvements	449,416	3.46%	$15,550	$15,550
391.1	Furniture and Fixtures	48,359	8.33%	4,028	4,028
391.3	Computer Equip. - PC	51,081	20.00%	10,216	10,216
391.5	Computer Equip. - Other	14,561	20.00%	2,912	2,912
392.1	Trans. Equip., Non-Unitized	117,486	9.67% 2/		11,361
392.2	Trans. Equip., Unitized	2,325,417	0.26% 2/		6,046
393	Stores Equipment	14,254	2.86%	408	408
394.1	Tools,Shop&Gar. Eq.-Non-Un.	695,436	6.36%	44,230	44,230
394.3	Vehicle Maintenance Equip.	22,859	5.00%	1,143	1,143
395	Laboratory Equipment	32,303	7.11%	2,297	2,297
396.1	Power Operated Equip.	151,847	6.02% 2/		9,141
396.2	Work Equipment Trailers	1,963,501	0.23% 2/		4,516
397.1	Radio Comm. Equip.-Fixed	242,997	7.42%	18,030	18,030
397.2	Radio Comm. Equip.-Mobile	140,365	7.13%	10,008	10,008
398	Miscellaneous Equipment	15,109	7.87%	1,189	1,189
	Total General Plant	$6,292,122		$110,011	$141,075
303	Intangible Plant - General	$55,404	0.00% 3/	$0	$0

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 15

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Common Plant				
389	Land	$988,648			
390	Structures and Improvements	7,005,825	2.25%	$157,631	$157,631
391.1	Furniture and Fixtures	539,419	7.61%	41,050	41,050
391.3	Computer Equip. - PC	420,753	9.76%	41,065	41,065
391.5	Computer Equip. - Other	11,912	20.00%	2,382	2,382
392.1	Trans. Equip., Non-Unitized	6,203	0.00% 3/		0
392.2	Trans. Equip., Unitized	618,075	4.11% 2/		25,403
392.3	Aircraft	483,574	3.77%	18,231	18,231
393	Stores Equipment	10,773	3.57%	385	385
394.1	Tools, Shop & Gar. Equip.	60,254	5.79%	3,489	3,489
394.3	Vehicle Maint. Equip.	44,545	5.59%	2,490	2,490
394.4	Vehicle Refueling Equip.	28,124	5.48%	1,541	1,541
397.1	Radio Comm. Equip.-Fixed	181,709	6.69%	12,156	12,156
397.2	Radio Comm. Equip.-Mobile	77,331	6.67%	5,158	5,158
397.3	General Tele. Comm. Equip.	105,405	10.00%	10,541	10,541
397.5	Supervisory & Tele. Equip.	223	6.69%	15	15
397.8	Network Equipment	60,492	20.00%	12,098	12,098
398	Miscellaneous Equipment	119,104	5.40%	6,432	6,432
	Total Common Plant	$10,762,369		$314,664	$340,067
303	Intangible Plant - Common	$5,456,184	4/	$442,126	$442,126
	CWIP in Service 5/				
	Distribution	$382,467	4.56%	$17,440	$17,440
	General	51,213	1.92%	983	983
	Common	67,043	2.94%	1,970	1,970
	Intangible - Common	(249)	2.95%	(7)	(7)
	Total CWIP	$500,474		$20,386	$20,386
	Total Gas Plant in Service	$100,963,935		$4,423,602	$4,480,069

1/ See Rule 38.5.123, Statement C, pages 3 - 5.
2/ Charged to a clearing account.
3/ Fully amortized/depreciated.
4/ Amortization based on the life of each item.
5/ Composite rates by function.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION EXPENSE ON PLANT ADDITIONS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Acct. No.	Account	Amount	Annual Depreciation Rate	Annual Depreciation Amount
	Production			
333	Field Compressor Station Equip.	$24,906	3.33%	$829
	Total Production	$24,906		$829
	Distribution			
376	Mains	1,354,848	2.97%	40,239
378	Meas. & Reg. Equip.-General	26,647	3.14%	837
380	Services	1,149,831	8.18%	94,056
381	Positive Meters	395,073	3.53%	13,946
383	Regulators	42,090	1.77%	745
387.1	Cathodic Protection Equip.	107,305	3.21%	3,444
	Total Distribution	$3,075,794		$153,267
	General			
392.2	Trans. Equip., Unitized	139,603	0.26%	363
394.1	Tools,Shop&Gar. Eq.-Non-Un.	64,203	6.36%	4,083
396.2	Work Equipment Trailers	347,473	0.23%	799
397.1	Radio Comm. Equip.-Fixed	11,546	7.42%	857
	Total General	$562,825		$6,102
	Common			
390	Structures and Improvements	$53,796	2.25%	$1,210
391.1	Furniture and Fixtures	83,974	7.61%	6,390
391.3	Computer Equip. - PC	57,512	9.76%	5,613
392.2	Trans. Equip., Unitized	66,479	4.11%	2,732
394.1	Tools,Shop&Gar. Eq.-Non-Un.	14,211	5.79%	823
397.1	Radio Comm. Equip.-Fixed	63,425	6.69%	4,243
397.3	General Tele. Comm. Equip.	58,374	10.00%	5,837
397.8	Network Equipment	8,479	20.00%	1,696
398	Miscellaneous Equipment	13,128	5.40%	709
	Total Common	$419,378		$29,253
303	Intangible Plant - Common	$5,269,371	1/	$360,844
	Total	$9,352,274		$550,295

1/ Amortization based on the life of each item.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION AND AMORTIZATION EXPENSES

See Pages 8 through 12 for Montana-Dakota's depreciation rates as set forth in a study performed by AUS Consultants as of December 31, 2008 for gas and common plant.

Table 1

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008 and Related Annual Depreciation Expense Under Present and Proposed Rates

			Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Rates: Proposed Gross Salv Rates		Proposed Rates: Proposed COR Rates		Proposed Rates: Total Proposed Rates		
Account No.	Description	Original Cost 12/31/08	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Net Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	DEPRECIABLE PLANT												
	Distribution Plant												
374.20	Rights of Way	322,677.60	0.75%	2,420.08	1.39%	4,485.22	0.00%	0.00	0.00%	0.00	1.39%	4,485.22	2,065.14
375.00	Distr. Meas & Reg Station Structures	609,311.11	2.57%	15,659.30	1.52%	9,261.53	0.18%	1,096.76	1.07%	6,519.63	2.77%	16,877.92	1,218.62
	Mains												
376.10	Mains-Steel	41,975,049.45	1.92%	805,920.95	1.77%	742,958.38	0.00%	0.00	1.07%	449,133.03	2.84%	1,192,091.40	386,170.45
376.20	Mains-Plastic	63,935,958.79	1.92%	1,227,570.41	1.99%	1,272,325.58	0.00%	0.00	1.06%	677,721.16	3.05%	1,950,046.74	722,476.33
376.30	Mains-Valves	447,328.09	1.92%	8,588.70	2.29%	10,243.81	0.00%	0.00	1.25%	5,591.60	3.54%	15,835.41	7,246.71
376.40	Mains-Manholes	69,919.29	1.92%	1,342.45	1.83%	1,279.52	0.00%	0.00	1.06%	741.14	2.89%	2,020.67	678.22
376.50	Mains-Bridge & River Crossings	19,818.03	1.92%	380.51	2.06%	408.25	0.00%	0.00	1.07%	212.05	3.13%	620.30	239.79
	Total Mains	106,448,073.65	1.92%	2,043,803.02	1.90%	2,027,215.54	0.00%	0.00	1.06%	1,133,398.98	2.97%	3,160,614.52	1,116,811.50
378.00	Meas & Reg Station Equip-General	2,140,308.63	2.96%	63,353.14	2.22%	47,514.85	0.00%	0.00	0.92%	19,690.84	3.14%	67,205.69	3,852.55
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	3.54%	36,420.29	2.81%	28,909.90	0.00%	0.00	0.94%	9,670.93	3.75%	38,580.82	2,160.53
	Services												
380.10	Services-Steel	7,285,187.87	5.66%	412,341.63	2.48%	180,672.66	0.00%	0.00	7.17%	522,347.97	9.65%	703,020.63	290,679.00
380.20	Services-Plastic	42,690,273.23	5.66%	2,416,269.46	2.50%	1,067,256.83	0.00%	0.00	5.41%	2,309,543.78	7.91%	3,376,800.61	960,531.15
380.30	Farm & Fuel Lines	248,640.18	5.66%	14,073.03	3.34%	8,304.58	0.00%	0.00	7.67%	19,070.70	11.01%	27,375.28	13,302.25
	Total Services	50,224,101.28	5.66%	2,842,684.12	2.50%	1,256,234.07	0.00%	0.00	5.68%	2,850,962.45	8.18%	4,107,196.52	1,264,512.40
381.00	Meters	55,172,050.24	3.19%	1,759,988.40	2.91%	1,605,506.66	0.00%	0.00	0.62%	342,066.71	3.53%	1,947,573.37	187,584.97
383.00	Service Regulators	5,555,207.98	2.59%	143,879.89	2.16%	119,992.49	-0.39%	(21,665.31)	0.00%	0.00	1.77%	98,327.18	(45,552.71)
385.00	Industrial Meas. & Reg. Station Equip	875,376.89	3.04%	26,611.46	2.43%	21,271.66	0.35%	3,063.82	0.53%	4,639.50	3.31%	28,974.98	2,363.52
	MISCELLANEOUS EQUIPMENT												
386.10	Misc Property on Customers Premise	1,679.84	5.19%	87.18	2.39%	40.15	0.00%	0.00	0.00%	0.00	2.39%	40.15	(47.03)
386.20	CNG Refueling station	261,880.34	3.70%	9,689.57	0.27%	707.08	0.00%	0.00	0.00%	0.00	0.27%	707.08	(8,982.49)
386.30	CNG Lease/Demo	0.00											
	TOTAL Account 386	263,560.18	3.71%	9,776.75	0.28%	747.23	0.00%	0.00	0.00%	0.00	0.28%	747.23	(9,029.52)

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No.	Description	Original Cost 12/31/08	Present Rates Rate %	Present Rates Annual Accrual	Proposed Plant Only Rates Rate %	Proposed Plant Only Rates Annual Accrual	Proposed Gross Salv Rates Rate %	Proposed Gross Salv Rates Annual Accrual	Proposed COR Rates Rate %	Proposed COR Rates Annual Accrual	Total Proposed Rates Rate %	Total Proposed Rates Annual Accrual	Net Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	OTHER EQUIPMENT												
387.10	Cathodic Protection Equipment	1,737,817.71	5.75%	99,924.52	3.21%	55,783.95	0.00%	0.00	0.00%	0.00	3.21%	55,783.95	(44,140.57)
387.20	Other Distribution Equipment	588,025.51	1.42%	8,349.96	0.99%	5,821.45	0.00%	0.00	0.00%	0.00	0.99%	5,821.45	(2,528.51)
	TOTAL Account 387	2,325,843.22	4.66%	108,274.48	2.65%	61,605.40	0.00%	0.00	0.00%	0.00	2.65%	61,605.40	(46,669.08)
	TOTAL Distribution Plant	224,965,332.67	3.14%	7,052,870.93	2.30%	5,182,744.55	-0.01%	(17,504.73)	1.94%	4,366,949.04	4.24%	9,532,188.85	2,479,317.92
	General Plant												
390.00	General Structures	5,835,295.28	3.73%	217,656.51	3.09%	180,310.62	-0.04%	(2,334.12)	0.41%	23,924.71	3.46%	201,901.22	(15,755.29)
	OFFICE FURNITURE & EQUIPMENT												
391.10	Office Furniture & Equipment	415,861.93	4.97%	20,668.34	6.59%	27,412.62	0.00%	0.00	0.00%	0.00	6.59%	27,412.62	6,744.28
391.30	Computer Equipment - PC	828,118.21	26.02%	215,476.36	11.28%	93,383.50	0.00%	0.00	0.00%	0.00	11.28%	93,383.50	(122,092.86)
391.50	Other Computer Equipment	53,696.84	0.00%	0.00	4.97%	2,667.08	0.00%	0.00	0.00%	0.00	4.97%	2,667.08	2,667.08
	TOTAL Account 391	1,297,676.98	18.20%	236,144.70	9.51%	123,463.20	0.00%	0.00	0.00%	0.00	9.51%	123,463.20	(112,681.50)
	TRANSPORTATION EQUIPMENT												
392.10	Transportation Equipment (Trailers)	397,059.69	4.36%	17,311.80	12.35%	49,036.87	-2.68%	(10,641.20)	0.00%	0.00	9.67%	38,395.67	21,083.87
392.20	Trans Equipment (Cars & Trucks)	8,775,094.21	21.13%	1,854,177.41	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	(1,854,177.41)
	TOTAL Account 392	9,172,153.90	20.40%	1,871,489.21	0.53%	49,036.87	-0.12%	(10,641.20)	0.00%	0.00	0.42%	38,395.67	(1,833,093.54)
393.00	Stores Equipment	148,282.28	2.49%	3,692.23	2.44%	3,613.53	0.00%	0.00	0.00%	0.00	2.44%	3,613.53	(78.70)
	TOOLS, SHOP & GARAGE EQ.												
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89	6.62%	166,535.29	5.65%	142,108.78	0.00%	0.00	0.00%	0.00	5.65%	142,108.78	(24,426.51)
394.30	Vehicle Maintenance Equipment	37,100.02	5.78%	2,144.38	7.12%	2,640.27	0.00%	0.00	0.00%	0.00	7.12%	2,640.27	495.89
394.40	Vehicle Refueling Equipment	26,852.90	4.72%	1,267.46	10.32%	2,772.05	0.00%	0.00	0.00%	0.00	10.32%	2,772.05	1,504.59
	TOTAL Account 394	2,579,591.81	6.59%	169,947.13	5.72%	147,521.10	0.00%	0.00	0.00%	0.00	5.72%	147,521.10	(22,426.03)
395.00	Laboratory Equipment	172,283.97	7.67%	13,214.18	6.95%	11,980.02	0.00%	0.00	0.00%	0.00	6.95%	11,980.02	(1,234.16)

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

			Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Gross Salv Rates		Proposed COR Rates		Total Proposed Rates		
Account No.	Description	Original Cost 12/31/08	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Net Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	POWER OPERATED EQUIPMENT												
396.10	Work Equipment (Trailers)	530,575.86	5.76%	30,561.17	10.19%	54,065.68	-4.17%	(22,125.01)	0.00%	0.00	6.02%	31,940.67	1,379.50
396.20	Power Operated Equipment	6,142,234.08	0.00%	0.00	31.72%	1,948,316.65	-30.77%	(1,889,965.43)	0.00%	0.00	0.95%	58,351.22	58,351.22
	TOTAL Account 396	6,672,809.94	0.46%	30,561.17	30.01%	2,002,382.33	-28.65%	(1,912,090.44)	0.00%	0.00	1.35%	90,291.89	59,730.72
	COMMUNICATION EQUIPMENT												
397.10	Radio Communication Equip. (Fixed)	226,847.00	7.37%	16,718.62	6.07%	13,763.90	0.00%	0.00	0.00%	0.00	6.07%	13,763.90	(2,954.72)
397.20	Radio Communication Equip. (Mobile)	468,875.34	7.34%	34,415.45	4.06%	19,052.43	0.00%	0.00	0.00%	0.00	4.06%	19,052.43	(15,363.02)
397.30	General Telephone Communication Equip.	56,947.69	9.88%	5,626.43	10.69%	6,089.15	0.00%	0.00	0.00%	0.00	10.69%	6,089.15	462.72
397.80	Network Equipment	172,146.81	26.26%	45,205.75	17.68%	30,435.15	0.00%	0.00	0.00%	0.00	17.68%	30,435.15	(14,770.60)
	TOTAL Account 397	924,816.84	11.03%	101,966.25	7.50%	69,340.63	0.00%	0.00	0.00%	0.00	7.50%	69,340.63	(32,625.62)
398.00	Miscellaneous Equipment	56,850.20	1.27%	722.00	9.43%	5,361.40	0.00%	0.00	0.00%	0.00	9.43%	5,361.40	4,639.40
	Sub-Total (General Plant) Amortization	**5,179,502.08**		**525,686.49**	**6.98%**	**361,279.88**	**0.00%**	**0.00**	**0.00%**	**0.00**	**6.98%**	**361,279.88**	**(164,406.61)**
	TOTAL General Plant	26,859,761.20	9.85%	2,645,393.38	9.65%	2,593,009.70	-7.17%	(1,925,065.76)	0.09%	23,924.71	2.58%	691,868.66	(1,953,524.72)
	TOTAL Depreciable Plant	251,825,093.87	3.85%	9,698,264.31	3.09%	7,775,754.25	-0.77%	(1,942,570.49)	1.74%	4,390,873.75	4.06%	10,224,057.51	525,793.20
	NON-DEPRECIABLE PLANT												
374.1	Land (Distribution)	138,261.79											
389	Land & Land Rights (General)	1,328,891.91											
	Total Land	1,467,153.70											
	INTANGIBLE PLANT												
303	Miscellaneous Intangible Plant	3,949,065.10											
	Total Intangible Plant	3,949,065.10											
	TOTAL Non-Depreciable Plant	5,416,218.80											
	TOTAL Plant in Service	257,241,312.67											

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account		Original	Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Gross Salv Rates		Proposed COR Rates		Total Proposed Rates		Net
Account No.	Description	Cost 12/31/08	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	DEPRECIABLE PLANT												
	General Plant												
390.0	General Structures	26,865,571.47	2.93%	787,161.24	2.51%	674,325.84	0.07%	18,805.90	-0.33%	(88,656.39)	2.25%	604,475.36	(182,685.88)
	OFFICE FURNITURE & EQUIPMENT												
391.1	Office Furniture & Equipment	3,072,248.50	4.95%	152,076.30	6.75%	207,227.63	0.00%	0.00	0.00%	0.00	6.75%	207,227.63	55,151.33
391.2	Computer Equipment - Honeywell	0.00	1.52%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00
391.3	Computer Equipment - PC	2,168,689.65	23.29%	505,087.82	7.28%	157,939.09	0.00%	0.00	0.00%	0.00	7.28%	157,939.09	(347,148.73)
391.4	Computer Equipment - Prime/Sun	7,552.14	26.51%	2,002.07	0.68%	51.47	0.00%	0.00	0.00%	0.00	0.68%	51.47	(1,950.60)
391.5	Computer Equipment - Other	1,049,321.00	0.46%	4,826.88	18.40%	193,100.24	0.00%	0.00	0.00%	0.00	18.40%	193,100.24	188,273.36
	TOTAL Account 391	6,297,811.29	10.54%	663,993.07	8.87%	558,318.43	0.00%	0.00	0.00%	0.00	8.87%	558,318.43	(105,674.64)
	TRANSPORTATION EQUIPMENT												
392.1	Transportation Equipment (Trailers)	113,614.30	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00 (1)	0.00%	0.00	0.00
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	13.33%	710,040.10	9.14%	486,854.20	-4.44%	(236,502.48)	0.00%	0.00	4.70%	250,351.72	(459,688.38)
	TOTAL Account 392	5,440,246.73	13.05%	710,040.10	8.95%	486,854.20	-4.35%	(236,502.48)	0.00%	0.00	4.60%	250,351.72	(459,688.38)
393.0	Stores Equipment	45,012.16	2.80%	1,260.34	3.32%	1,494.05	0.00%	0.00	0.00%	0.00	3.32%	1,494.05	233.71
	TOOLS, SHOP & GARAGE EQ.												
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	6.11%	25,223.33	6.71%	27,719.23	0.00%	0.00	0.00%	0.00	6.71%	27,719.23	2,495.90
394.3	Vehicle Maintenance Equipment	179,785.84	4.75%	8,539.83	5.33%	9,591.43	0.00%	0.00	0.00%	0.00	5.33%	9,591.43	1,051.60
394.4	Vehicle Refueling Equipment	612,112.44	4.38%	26,810.52	3.28%	20,101.35	0.00%	0.00	0.00%	0.00	3.28%	20,101.35	(6,709.17)
	TOTAL Account 394	1,204,718.75	5.03%	60,573.68	4.77%	57,412.01	0.00%	0.00	0.00%	0.00	4.77%	57,412.01	(3,161.67)
396.2	Power Operated Equipment	53,432.48	2.69%	1,437.33	18.22%	9,735.40	-10.64%	(5,685.22)	0.00%	0.00	7.58%	4,050.18	2,612.85
	COMMUNICATION EQUIPMENT												
397.1	Radio Communication Equip. (Fixed)	379,772.93	4.99%	18,950.67	4.70%	17,844.86	0.00%	0.00	0.00%	0.00	4.70%	17,844.86	(1,105.81)
397.2	Radio Communication Equip. (Mobile)	612,124.91	4.08%	24,974.70	4.13%	25,251.65	0.00%	0.00	0.00%	0.00	4.13%	25,251.65	276.95
397.3	General Telephone Communication Equip.	496,688.56	8.72%	43,311.24	7.78%	38,662.59	0.00%	0.00	0.00%	0.00	7.78%	38,662.59	(4,648.65)
397.5	Supervisory & Telemetering Equip.	41,918.98	0.35%	146.72	4.24%	1,777.12	0.00%	0.00	0.00%	0.00	4.24%	1,777.12	1,630.40
397.8	Network Equipment	424,430.36	17.95%	76,185.25	18.95%	80,428.99	0.00%	0.00	0.00%	0.00	18.95%	80,428.99	4,243.74
	TOTAL Account 397	1,954,935.74	8.37%	163,568.58	8.39%	163,965.21	0.00%	0.00	0.00%	0.00	8.39%	163,965.21	396.63

Table 1

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Rates: Proposed Plant Only Rates Rate % (f)	Proposed Plant Only Rates Annual Accrual (g)	Proposed Gross Salv Rates Rate % (f)	Proposed Gross Salv Rates Annual Accrual (g)	Proposed COR Rates Rate % (h)	Proposed COR Rates Annual Accrual (i)	Total Proposed Rates Rate % (j)	Total Proposed Rates Annual Accrual (k)	Net Change Depr.. Exp. (l)
398.0	Miscellaneous Equipment	932,731.72	2.41%	22,478.83	4.01%	37,429.17	0.00%	0.00	0.00%	0.00	4.01%	37,429.17	14,950.34
	Sub-Total (General Plant) Amortization	**10,435,209.66**	**8.74%**	**911,874.50**	**7.84%**	**818,618.87**	**0.00%**	**0.00**	**0.00%**	**0.00**	**7.84%**	**818,618.87**	**(93,255.63)**
	TOTAL General Plant	42,794,460.34	5.63%	2,410,513.17	4.65%	1,989,534.31	-0.52%	(223,381.80)	-0.21%	(88,656.39)	3.92%	1,677,496.13	(733,017.04)
	TOTAL Depreciable Plant	42,794,460.34	5.63%	2,410,513.17	4.65%	1,989,534.31	-0.52%	(223,381.80)	-0.21%	(88,656.39)	3.92%	1,677,496.13	(733,017.04)
	Amortizable Plant												
392.3	Aircraft Equipment	2,937,920.42											
	TOTAL Amortizable Plant	2,937,920.42											
	NON-DEPRECIABLE PLANT												
389.0	Land & Land Rights (General)	2,778,248.40											
	Total Land	2,778,248.40											
	INTANGIBLE PLANT												
303.0	Miscellaneous Intangible Plant	22,784,037.44											
	Total Intangible Plant	22,784,037.44											
	TOTAL Non-Depreciable Plant	25,562,285.84											
	TOTAL Plant in Service	71,294,666.60											

(1) Account Fully Depreciated. No further current depreciation accrual.

MONTANA-DAKOTA UTILITIES CO.
RECONCILIATION OF DEPRECIABLE GAS PLANT
GAS UTILITY - MONTANA
DECEMBER 31, 2010 AND DECEMBER 31, 2011

	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance
Depreciable Plant			
Production	$2,972,781	$3,096,756	$3,034,769
Distribution	70,089,153	73,234,314	71,661,733
General	1,929,551	1,688,865	1,809,209
General - Amortized	56,115	55,404	55,759
	$75,047,600	$78,075,339	$76,561,470
Depreciable Plant Charged to a Clearing Account			
Transportation Equipment	$2,297,976	$2,373,101	$2,335,538
Power Operated Equipment	138,401	151,847	145,124
Work Equipment	1,580,659	1,789,764	1,685,211
	$4,017,036	$4,314,712	$4,165,873
Non-Depreciable Plant			
Distribution	$15,962	$15,962	15,962
General	7,131	7,131	7,131
	$23,093	$23,093	$23,093
Common Plant in Service - Gas			
Depreciable	$9,130,272	$8,972,993	$9,051,632
Charged to Clearing Account	556,020	591,038	573,529
Depreciable - Amortized	2,697,442	2,821,499	2,759,471
Non-Depreciable	952,893	988,648	970,771
	$13,336,627	$13,374,178	$13,355,403
Total Gas Plant in Service	$92,424,356	$95,787,322	$94,105,839

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION EXPENSE CHARGED TO OTHER THAN PRESCRIBED DEPRECIATION AND AMORTIZATION EXPENSE

The Company charges all depreciation and amortization expense to prescribed accounts, with the exception of the following:

1. Depreciation of transportation and work equipment in FERC plant accounts 392 and 396 is charged to FERC clearing account 184.00.
2. Depreciation of aircraft in FERC plant account 392 is charged to FERC clearing account 184.01.
3. Depreciation of a portion of general plant structures in FERC account 390 is charged to FERC account 416 for non-utility operations.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO PER BOOKS TAXABLE INCOME
ELECTRIC UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Operating Income	Adjustment No.	Pro Forma Adjustment	Reference
Current Income Taxes			
Interest Expense Annualization 1/	19	($51,878)	Statement J, Page 8
Tax Depreciation on Plant Additions 1/	20	2,817,177	Statement J, Page 9
Other Tax Deductions	21	(400,022)	Statement J, Page 10
Total Adjustment to Taxable Income		$2,365,277	
Income Taxes on Pro Forma Adjustments	22	(1,923,771)	Statement J, Page 11
Elimination of Closing/Filing and prior-period	23	1,560,882	Statement J, Page 12
Total Adjustment to Current Income Taxes		($362,889)	
Deferred Income Taxes			
Elimination of Closing/Filing and prior-period	23	(1,302,970)	Statement J, Page 12
Deferred Income Taxes on Plant Additions	20	1,109,616	Statement J, Page 9
Other Tax Deductions	21	38,579	Statement J, Page 10
Total Adjustment to Deferred Income Taxes		($154,775)	
Rate Base			
Accumulated Deferred Income Taxes -			
Plant Additions and Normalization	K & L	1,862,288	Statement J, Page 17
Pensions and Benefits	H	846,179	Statement E, Page 6
Injuries and Damages	I	(41,583)	Statement E, Page 7
Deferred FAS 106 costs	J	105,855	Statement E, Page 8
Unamortized Loss on debt	G	(31,526)	Statement E, Page 5
Total Adjustment to Current Income Taxes		$2,741,213	
Accumulated Investment Tax Credits	M	(3,488)	Statement J, Page 19

1/ Amount is shown before income tax effect.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Utility				Total
	Gas	Electric	Total	Non-Utility	Company
1900 Account M-1's					
Pension Expense	$9,465,440	$7,744,450	$17,209,890		$17,209,890
Accrued Vacation	31,009	25,360	56,369		56,369
Property Insurance Adjustment	(143,936)	(213,458)	(357,394)		(357,394)
Bad Debt Expense	(1,393)	12,874	11,481	(5,658)	5,823
Management Incentive Compensation	(45,007)	(116,191)	(161,198)		(161,198)
Sundry Reserves	(13,254)	(36,331)	(49,585)		(49,585)
Customer Advances	605,145	702,140	1,307,285		1,307,285
Restricted Stock Bonus Plan	(231,830)	(344,179)	(576,009)		(576,009)
Capitalized Overheads	64,557		64,557		64,557
Supplemental Income Security Plan	324,503	481,763	806,266		806,266
Contributions In Aid of Construction				(72,730)	(72,730)
FAS 106 - OPRB	4,789,447	5,810,547	10,599,994	1,071,901	11,671,895
Prepaid Demand Charges	(136,885)		(136,885)		(136,885)
Deferred Compensation - Directors	(75,593)	(112,228)	(187,821)		(187,821)
Board of Directors - Retirement Benefits	(29,093)	(43,192)	(72,285)		(72,285)
PCB Related Income	(12,991)		(12,991)		(12,991)
Reserved Revenues		640,000	640,000		640,000
Contingency Reserve	(5,246,199)		(5,246,199)	362,946	(4,883,253)
FAS 158 Post Retirement	(4,593,957)	(5,573,379)	(10,167,336)	(1,028,149)	(11,195,485)
WAPA Fiber Demand Revenue		(61,644)	(61,644)		(61,644)
2820 Account M-1's					
Liberalized Depreciation and Other Property Timing Differences	(12,903,330)	(38,959,011)	(51,862,341)	(258,972)	(52,121,313)
Contributions In Aid of Construction	(163,488)	(601,937)	(765,425)		(765,425)
Acquisition Adjustments	2,819		2,819		2,819
Montana Net Negative Salvage		346,195	346,195		346,195

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Utility				Total
	Gas	Electric	Total	Non-Utility	Company
2830 Account M-1's					
Unrecovered Purchased Gas Cost	(498,582)		(498,582)		(498,582)
Rate Case Expense	20,282	85,449	105,731		105,731
Amort of Loss on Bond Retirements	149,376	559,144	708,520		708,520
FAS 106 - Deferred Expense	54,531		54,531		54,531
Margin Sharing Adjustment (MSA)		1,724,798	1,724,798		1,724,798
F&PP Deferral		(935,387)	(935,387)		(935,387)
FAS 158 Pension	(16,616,628)	(13,595,423)	(30,212,051)		(30,212,051)
Regulatory Assets Awaiting Recovery	363,120	5,349,402	5,712,522		5,712,522
Big Stone II Cost Recovery		(1,389,057)	(1,389,057)		(1,389,057)
Permanent M-1's					
Preferred Stock Expense Amortization	6,685	18,323	25,008		25,008
Disallowed Meals and Entertainment	51,746	76,822	128,568	6,522	135,090
Lobbying Expense				41,079	41,079
Federal Nonhwy Use Tax Credit	9,629	14,295	23,924		24,689
SISP	(350,787)	(520,783)	(871,570)		(899,453)
SISP - Unrealized Gain/Loss	462,617	686,808	1,149,425		1,186,197
Medicare Part D Subsidiary	(275,763)	(225,529)	(501,292)		(501,292)
401(k) Dividend Deduction	(1,830,585)	(1,497,119)	(3,327,704)		(3,327,704)
Dividend Received Deduction	(8,823)	(13,099)	(21,922)		(21,922)
Total M-1 Deductions	($26,777,218)	($39,959,577)	($66,736,795)	$116,939	($66,610,202)

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
TAX DEDUCTIONS
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Utility				Total
	Gas	Electric	Total	Non-Utility	Company
Operating Revenue	$247,677,369	$224,393,171	$472,070,540		$472,070,540
Non-Utility Income (before income taxes)				$9,448,816	9,448,816
Total Revenue	$247,677,369	$224,393,171	$472,070,540	$9,448,816	$481,519,356
Operating Expense:					
O&M Expense	217,685,550	$133,582,157	351,267,707	6,731,141	357,998,848
Depreciation Expense	9,814,146	32,005,151	41,819,297		41,819,297
Taxes Other than Income	6,138,074	9,434,923	15,572,997		15,572,997
Total Operating Expense	233,637,770	175,022,231	408,660,001	6,731,141	415,391,142
Operating Income	14,039,599	49,370,940	63,410,539	2,717,675	66,128,214
Interest Expense/Other Inc. & Deduct.	4,431,782	13,745,266	18,177,048	(599,116)	17,577,932
Book Taxable Income before Adjustments	9,607,817	35,625,674	45,233,491	3,316,791	48,550,282
Deductions and Adjustments to Book Income:					
Tax Deductions 1/	(26,777,218)	(39,959,577)	(66,736,795)	116,939	(66,619,856)
Preferred Dividend Paid Deduction	(47,187)	(129,344)	(176,531)		(176,531)
Total Deductions and Adjustments	(26,824,405)	(40,088,921)	(66,913,326)	116,939	(66,796,387)
Taxable Income - Before State Income Tax	(17,216,588)	(4,463,247)	(21,679,835)	3,220,699	(18,459,136)
Less: Deductible State Income Taxes	(829,462)	(214,026)	(1,043,488)	155,000	(888,488)
Federal Taxable Income	(16,387,126)	(4,249,221)	(20,636,347)	3,065,699	(17,570,648)
Federal Income Taxes @ 35%	(5,735,494)	(1,487,228)	(7,222,721)	1,072,995	(6,149,726)
Credits and Adjustments	(22,576)	(3,460,509)	(3,483,085)		(3,483,085)
State Income Taxes	(829,462)	(214,026)	(1,043,488)	155,000	(888,488)
Federal and State Income Taxes	(6,587,532)	(5,161,763)	(11,749,294)	1,227,995	(10,521,299)
Closing and Prior Year's Adjustment	(5,169,025)	(8,690,074)	(13,859,099)	(130,377)	(13,989,476)
Total Federal and State Income Taxes	($11,756,557)	($13,851,837)	($25,608,393)	$1,097,618	($24,510,775)

1/ See pages 2 - 3.

MONTANA DAKOTA UTILITIES CO.
COMPUTATION OF INCOME TAX LIABILITY AND TAX SAVINGS
BASED ON MDU RESOURCES GROUP, INC. 2010
CONSOLIDATED FEDERAL INCOME TAX RETURN

	Montana-Dakota Utilities Co.	MDU Resources Group, Inc. 1/
Net Taxable Income (Loss)	($73,367,704)	$129,115,277
Federal Income Tax:		
Statutory Taxes @ 35%	$0	$45,190,347
Less Credits:		
Foreign Tax Credit		9,741,577
General Business Credit	0	2,164,515
Total Tax	$0	$33,284,255
Tax Savings Arising From Consolidation	$0	

Montana Dakota Utilities Co. is a member of a group that files a consolidated Federal Income Tax Return. There are no tax savings available to Montana-Dakota Utilities Co. as a result of being included in a consolidated tax return during the test period.

1/ Reflects MDU Resources Group, Inc. and includible subsidiaries.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

	Montana
Operating Revenue	$74,110,974
Operating Expense:	
O&M Expense	63,604,342
Depreciation Expense	3,011,298
Taxes Other than Income	3,308,019
Total Operating Expense	69,923,659
Operating Income	4,187,315
Interest Expense	1,269,714
Book Taxable Income before Adjustments	2,917,601
Deductions and Adjustments to Book Income:	
Tax Deductions 1/	6,181,302
Preferred Dividend Paid Deduction	13,836
Total Deductions and Adjustments	6,195,138
Taxable Income - Before State Income Tax	(3,277,537)
Less: State Income Taxes	(386,615)
Federal Taxable Income	(2,890,922)
Federal Income Taxes @ 35%	(1,011,823)
Credits and Adjustments	29,134
State Income Taxes	(386,615)
Federal and State Income Taxes	(1,369,304)
Closing/Filing and Prior Period Adjustment	(1,560,882)
Total Federal and State Income Taxes	($2,930,186)

1/ See page 7.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

	Montana
1900 Account M-1's	
Pension Expense	($2,727,760)
Accrued Vacation	(8,936)
Property Insurance Adjustment	42,267
Bad Debt Expense	3,633
Management Incentive Compensation	12,970
Sundry Reserves	3,886
Customer Advances	86,962
Restricted Stock Bonus Plan	66,809
Capitalized Overheads	(18,606)
Supplemental Income Security Plan	(95,291)
FAS 106 - OPRB	(1,380,228)
Demand Charges	29,632
Deferred Compensation-Directors	21,784
Board of Director - Retirement Benefits	8,384
PCB Related Income	4,010
FAS 158 Post Retirement	1,323,891
2820 Account M-1's	
Liberalized Depreciation and Other Property Timing Differences	3,575,173
Property Timing Differences - Common	21,308
2830 Account M-1's	
Unrecovered Purchased Gas Cost Adjustment	(52,394)
Amortization of Loss on Bond Retirements	(43,800)
FAS 106 - Deferred Expense	(38,668)
FAS 158 Pension	4,788,597
Permanent M-1's	
Preferred Stock Expense Amortization	(1,960)
Meals & Entertainment	(14,912)
Federal Nonhwy Use Tax Credit	(2,775)
Supplemental Income Security Plan	101,090
Supplemental Income Security Plan - Unrealized Gain/Loss	(133,317)
Medicare Part D Subsidiary	79,470
401(K) Dividend Deduction	527,540
Dividend Received Deduction	2,543
Total M-1 Deductions	$6,181,302

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ADJUSTMENT FOR INTEREST EXPENSE ANNUALIZATION
ADJUSTMENT NO. 19

	Per Books	Pro Forma Adjustment	Pro Forma
Rate Base 1/	$43,247,498	$512,333	$43,759,831
Weighted Cost of Debt 2/			2.783%
Interest Expense - Pro Forma			$1,217,836
Interest Charges as Recorded 3/			1,269,714
Interest Expense Annualization Adjustment			($51,878)

1/ Rule 38.5.175, Overall Cost of Service, page 7.
2/ Rule 38.5.146, Statement F, page 1, Long and Short Term Debt.
3/ Reflects long and short term interest and amortization of loss on debt.

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAX ON PLANT ADDITIONS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 20

Tax Depreciation Deduction	
Tax Depreciation 1/	$3,092,325
Book Depreciation 2/	275,148
Net Tax Depreciation on Plant Additions	$2,817,177
Deferred Income Taxes on Plant Additions	
- Current	$1,109,616

1/ See Rule 38.5.169, Statement J, page 18.
2/ Includes depreciation on accounts charged to clearing accounts.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
OTHER TAX DEDUCTIONS
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 21

	Pro Forma Adjustment
1900 Account Other Tax Deductions	
Supplemental Income Security Plan	$95,291
Permanent Deduction	
Supplemental Income Security Plan	(101,090)
Unamortized Gain on SISP	133,317
Adjustment to eliminate 401(k) Dividend Deduction	(527,540)
Total tax deductions	($400,022)
Deferred Income Taxes	
Supplemental Income Security Plan	$38,579

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
CALCULATION OF ADJUSTMENT TO
CURRENT INCOME TAXES
ADJUSTMENT NO. 22

	Pro Forma Adjustments
Operating Revenues	
Sales Revenues	($14,697,778)
Transportation Revenues	($121,356)
Other Revenues	47,286
Total Operating Revenues	(14,771,848)
Operating Expenses	
Operation and Maintenance	
Cost of Gas	(13,880,459)
Other O&M	247,767
Total O&M	(13,632,692)
Depreciation Expense	1,412,304
Taxes other Than Income	(32,520)
Total Operating Expenses	(12,252,908)
Gross Adjustments to Operating Income	(2,518,940)
Deductions and Adjustments to Book Income:	
Interest Annualization 1/	(51,878)
Tax Depreciation on Plant Additions 2/	2,817,177
Other Tax Deductions 3/	(400,022)
Total Adjustments to Taxable Income	2,365,277
Taxable Income	(4,884,217)
Federal & State Income Taxes @ 39.3875%	($1,923,771)
Elimination of Federal & State Prior Period Adj.	1,560,882
Total Adjustment to Current Income Taxes	($362,889)

1/ Rule 38.5.169, Statement J, page 8.
2/ Rule 38.5.169, Statement J, page 9.
3/ Rule 38.5.169, Statement J, page 10.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ADJUSTMENT TO CURRENT AND DEFERRED INCOME TAXES
FOR ROUNDING AND PRIOR YEAR'S AND CLOSING/FILING
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 23

Adjustment to Current Federal Income Taxes to Eliminate Closing/Filing and Prior Period Adjustments	$1,560,882
Adjustment to Deferred Income Taxes to Eliminate Closing/Filing and Prior Period Adjustments	($1,302,970)

MONTANA-DAKOTA UTILITIES CO./GREAT PLAINS NATURAL GAS CO.
ACCUMULATED DEFERRED INCOME TAXES
FOR THE YEAR ENDED DECEMBER 31, 2011

	Total Company	Electric	Gas	Other	Non-Utility
Account 190:					
January 2011	(60,196,099)	(14,485,344)	(18,859,606)	(26,203,018)	(648,131)
February	(61,099,875)	(14,513,633)	(19,722,063)	(26,216,048)	(648,131)
March	(58,277,730)	(13,055,656)	(18,340,285)	(26,233,658)	(648,131)
April	(57,895,237)	(12,906,650)	(18,082,615)	(26,257,841)	(648,131)
May	(57,429,854)	(12,948,686)	(17,545,517)	(26,287,520)	(648,131)
June	(57,414,356)	(12,924,410)	(16,673,024)	(27,178,817)	(638,105)
July	(56,341,727)	(12,906,408)	(15,611,151)	(27,186,063)	(638,105)
August	(55,020,795)	(12,691,345)	(14,496,868)	(27,194,477)	(638,105)
September	(54,447,225)	(12,806,208)	(13,799,732)	(27,203,180)	(638,105)
October	(53,948,746)	(12,699,303)	(13,405,206)	(27,206,132)	(638,105)
November	(54,343,179)	(12,657,272)	(13,913,944)	(27,261,348)	(510,615)
December	(65,712,445)	(17,889,799)	(19,460,096)	(27,720,226)	(642,324)
Account 282: (Other Property)					
January 2011	126,284,891	99,416,768	17,990,699	7,942,576	934,848
February	129,556,085	101,760,408	18,735,269	8,125,560	934,848
March	134,882,049	104,763,812	20,895,862	8,287,527	934,848
April	138,142,962	107,109,110	21,653,723	8,445,281	934,848
May	141,406,914	109,454,469	22,418,551	8,599,046	934,848
June	141,656,207	111,078,534	22,543,060	7,086,891	947,722
July	144,883,149	113,384,710	23,300,594	7,250,123	947,722
August	148,114,575	115,691,608	24,057,999	7,417,246	947,722
September	151,362,747	117,999,630	24,812,523	7,602,872	947,722
October	154,583,436	120,308,492	25,559,664	7,767,558	947,722
November	170,303,854	129,652,454	29,871,238	9,794,944	985,218
December	156,332,240	119,284,785	27,087,213	8,889,730	1,070,512
Account 283: (Other)					
January 2011	40,151,006	7,362,674	1,395,994	31,397,085	(4,747)
February	40,282,407	7,306,759	1,172,451	31,807,944	(4,747)
March	40,024,168	7,094,266	576,380	32,358,269	(4,747)
April	40,133,591	6,908,429	669,157	32,560,752	(4,747)
May	39,792,368	6,801,049	665,180	32,330,886	(4,747)
June	36,401,637	6,404,337	842,899	29,159,074	(4,673)
July	36,511,595	6,369,161	978,437	29,168,670	(4,673)
August	36,897,217	6,436,479	1,284,373	29,181,038	(4,673)
September	36,786,702	6,375,095	1,212,523	29,203,757	(4,673)
October	36,562,507	6,008,303	1,349,389	29,209,488	(4,673)
November	35,620,525	5,149,103	1,232,718	29,218,268	20,436
December	47,129,487	5,038,799	1,297,786	40,772,466	20,436
Total Company					
January 2011	106,239,798	92,294,098	527,087	13,136,643	281,970
February	108,738,617	94,553,534	185,657	13,717,456	281,970
March	116,628,487	98,802,422	3,131,957	14,412,138	281,970
April	120,381,316	101,110,889	4,240,265	14,748,192	281,970
May	123,769,428	103,306,832	5,538,214	14,642,412	281,970
June	120,643,488	104,558,461	6,712,935	9,067,148	304,944
July	125,053,017	106,847,463	8,667,880	9,232,730	304,944
August	129,990,997	109,436,742	10,845,504	9,403,807	304,944
September	133,702,224	111,568,517	12,225,314	9,603,449	304,944
October	137,197,197	113,617,492	13,503,847	9,770,914	304,944
November	151,581,200	122,144,285	17,190,012	11,751,864	495,039
December	137,749,282	106,433,785	8,924,903	21,941,970	448,624

MONTANA-DAKOTA UTILITIES CO.
DEFERRED INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
GAS UTILITY - MONTANA

	Montana
Gas Utility - Rate Base Deductions:	
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$1,385,866
Customer Advances	34,263
Demand Charges	11,675
Amortization of Loss on Bond Retirements	(17,596)
FAS 106 - Deferred Expense	(15,235)
Total Rate Base Deductions	1,398,973
Gas Utility - Timing Differences:	
Pension Expense	(1,078,377)
Accrued Vacation	(3,533)
Property Insurance Adjustment	16,868
Bad Debt Expense	1,432
Management Incentive Compensation	5,127
Sundry Reserves	1,561
Restricted Stock Bonus Plan	26,412
Capitalized Overheads	(7,355)
Supplemental Income Security Plan	(38,579)
FAS 106 - OPRB	(545,651)
Deferred Compensation-Directors	8,613
Board of Director - Retirement Benefits	3,315
PCB Related Income	1,591
FAS 158 Post Retirement	523,380
Unrecovered Purchased Gas Cost Adjustment	(20,643)
FAS 158 Pension	1,893,097
Closing/Filing and Out of Period	1,302,970
Total Timing Differences	2,090,228
Total Gas Utility	$3,489,201

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - MONTANA
DECEMBER 31, 2010 AND DECEMBER 31, 2011

	Total Company		Montana		
	Balance 12/31/10	Balance 12/31/11	Balance 12/31/10	Balance 12/31/11	Average Balance
Gas Utility - Rate Base Deductions:					
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$19,087,059	$28,288,114	$6,335,307	$8,956,878	$7,646,093
Net Negative Salvage	372,066	370,213	372,066	370,213	371,139
Contributions In Aid of Construction	(1,058,056)	(564,375)			
Customer Advances	(1,681,428)	(1,889,116)	(303,671)	(269,408)	(286,540)
Unamortized Loss on Debt	805,710	701,553	260,329	216,338	238,334
Deferred FAS 106	69,510	48,723	58,405	43,170	50,788
Prepaid Demand Charges	325,048	336,723	325,048	336,723	330,885
Full Normalization	2,366,654	2,317,991	574,000	576,594	575,297
Total Rate Base Deductions	$20,286,563	$29,609,826	$7,621,484	$10,230,508	$8,925,996

MONTANA-DAKOTA UTILITIES CO.
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
GAS UTILITY - MONTANA
DECEMBER 31, 2010 AND DECEMBER 31, 2011

	Total Company	
	Balance 12/31/10	Balance 12/31/11
Gas Utility - Current Timing Differences:		
Pension Expense	($12,745,563)	($16,134,645)
Management Incentive Compensation	(565,972)	(539,410)
Restricted Stock Bonus Plan	(758,398)	(883,688)
Uncollectable Accounts	(43,597)	(42,472)
Contingency Reserve	(1,990,931)	(154,761)
BOD Retirement	(250,391)	(234,787)
PCB Related Income	90,467	95,249
Capitalized Overheads	(518,736)	(535,344)
Prepaid Demand Charges (excluding MT)	692,650	722,602
Vacation Pay	(1,290,442)	(1,409,550)
Property Insurance	(148,389)	(84,970)
Sundry Reserves	(26,390)	(22,080)
SISP (incl. SISP OCI)	(6,523,952)	(7,235,938)
FAS 106	(674,654)	(2,327,306)
Deferred Compensation - Directors	(415,237)	(402,058)
FAS 106 Post Retirement	372,538	1,961,975
Purchased Gas Adjustment	239,293	417,662
Rate Case Expense	19,641	12,542
FAS 106 Deferred Costs (MT and SD)	69,510	48,723
FAS 106 Pension	12,913,192	19,433,435
Reg. Assets Awaiting Recovery (MGP sites)	356,119	208,873
Bond Costs	931,317	701,553
Unrealized Gain/Loss on SISP Investments	646,730	0
	($9,621,195)	($6,404,395)
Total Gas Utility	$10,665,368	$23,205,431

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Adjustments		Pro Forma Balance @ 12/31/12	Average Balance 12/31/12	Pro Forma Adjustment	Adjustment
Liberalized Depreciation	$6,707,373	$9,327,091	$8,017,232	$1,109,616	1/	$10,436,707	$9,881,899	$1,864,667	K
Full Normalization	574,000	576,594	575,297	(53,293)	2/	523,301	549,948	(25,349)	L
Prepaid Demand Charges	325,048	336,723	330,885			336,723	336,723	5,838	K
Customer Advances	(303,671)	(269,408)	(286,540)			(269,408)	(269,408)	17,132	K
Deferred FAS 106	58,405	43,170	50,788	156,643	3/		156,643	105,855	J
Unamortized Loss on Debt	260,329	216,338	238,334	(19,061)	4/	197,277	206,808	(31,526)	G
Provision for Pensions & Benefits				846,179	5/		846,179	846,179	H
Provision for Injuries & Damages				(41,583)	6/		(41,583)	(41,583)	I
Balance	$7,621,484	$10,230,508	$8,925,996	$1,998,501		$11,224,600	$11,667,209	$2,741,213	
Accumulated Investment Tax Credits									
Balance	$6,977	$1,191	$4,084	($1,191)	7/	$0	$596	($3,488)	M

1/ Deferred taxes on plant additions. See page 18.
2/ See page 20.
3/ See Rule 38.5.143, Statement E, page 8.
4/ See Rule 38.5.143, Statement E, page 5.
5/ See Rule 38.5.143, Statement E, page 6.
6/ See Rule 38.5.143, Statement E, page 7.
7/ See page 19.

MONTANA-DAKOTA UTILITIES CO.
TAX DEPRECIATION ON PLANT ADDITIONS
GAS UTILITY - MONTANA
PRO FORMA

2012 Plant Additions	Plant Additions	Annual Depreciation	Book Depr. 1/ for Taxes	Bonus Tax 2/ Depreciation	Tax 2/ Depreciation	Total Tax Depreciation	Book/Tax Difference	Deferred Income Taxes
Production	$24,906	$829	$414	$12,453	$1,779	$14,232	$13,818	$5,443
Distribution	3,075,794	153,267	76,634	1,537,897	76,895	1,614,792	1,538,158	605,842
General								
Other	423,222	5,739	2,869	211,611	30,231	241,842	238,973	94,125
Transportation	139,603	363	182	69,801	13,960	83,761	83,579	32,920
Total General	$562,825	6,102	3,051	281,412	44,191	325,603	322,552	127,045
Common								
Other	241,591	19,698	9,849	120,795	17,257	138,052	128,203	50,496
Structures & Improvement	53,796	1,210	605	0	1,708	1,708	1,103	434
Computer Equip.	57,512	5,613	2,807	28,756	5,751	34,507	31,700	12,486
Transportation	66,479	2,732	1,366	33,240	6,648	39,888	38,522	15,173
Intangible	331,768	31,670	15,835	165,884	55,289	221,173	205,338	80,878
Intangible - CC&B 3/	1,053,582	329,174	164,587	526,791	175,579	702,370	537,783	211,819
Total Common	$1,804,728	390,097	195,049	875,466	262,232	1,137,698	942,649	371,286
Total Additions	$5,468,253	$550,295	$275,148	$2,707,228	$385,097	$3,092,325	$2,817,177	$1,109,616

1/ Annual depreciation divided by 2 to reflect half year convention.
2/ Tax depreciation rates are:

Production	14.286%
Distribution	5.000%
General & Common	14.286%
Structures & Improvements	3.175%
Transportation & Computer	20.000%
Intangible	33.330%
Bonus Depreciation	50.000%

3/ Tax depreciation has been taken as cost occured to the CC&B system. Tax depreciation is only calculated on the 2012 Pro Forma amount of $1,053,582.

MONTANA-DAKOTA UTILITIES CO.
INVESTMENT TAX CREDITS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT M

	Montana
Balance at December 31, 2010	$6,977
Balance at December 31, 2011	1,191
Average Balance	$4,084
2012 Adjustment	(1,191)
Balance at December 31, 2012	$0
Average Balance at December 31, 2012	$596
Pro Forma Adjustment	($3,488)

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES
TO REFLECT FULL NORMALIZATION
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT L

Amortization of deferred taxes to reflect full normalization	($53,293)

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR THE 2010 TAX YEAR

M-1 Line No.			
1	Net Income per Books		$240,659,282
2	Federal Income Tax		13,607,662
3	Excess of Capital Losses Over Capital Gains		0
4	Income Subject to Tax not Recorded on Books This Year:		
	Other		
	Dividends Received from Subsidiary Companies	$104,141,000	
	G/L on Intercompany Trans. Under Reg Sec 1.1502-13	360,116	
	Jt Venture & Partnership Ordinary Income	(6,571)	
	Contributions in Aid of Construction	1,418,339	
	Book Gain(Loss) on Disposition of Property	72,018	
	Ordinary Gain(Loss) on Retirement of Assets - Tax	(129,958)	
	Capital Gain(Loss) on Retirement of Assets - Tax	(45,638)	
	Federal Non-highway Use Tax Credit	20,133	
	Total		$105,829,439
5	Expenses Recorded on Books This Year not Deducted on This Return:		
	Depreciation		$34,196,531
	Meals & Entertainment		124,689
	Other		
	Capitalized Overheads	65,915	
	Bad Debt Expense per Books	891,220	
	Capitalized Property Taxes	2,216,430	
	State Income Tax Accrual per Books	640,845	
	Amortization per Books	3,594,953	
	Amortization of Loss on Bond Retirements	719,511	
	Book Depreciation Charged to Expense	864,911	
	Capitalized Tax Depreciation	1,630,750	
	Lobbying Expense	71,255	
	Penalties	151	
	Deferred Compensation - Net Deferral	387,699	
	Customer Advances	1,208,659	
	Management Incentive Compensation	137,651	
	Preferred Stock Expense - Amortization	30,600	
	Prepaid Demand Charges	87,409	
	Sundry Reserves	949	
	Contingency Reserve	250,000	
	Big Stone II - Assets Awaiting Recovery & Amortization	1,722,488	
	Reusable Property to Expense	133	
	Restricted Stock Bonus Plan	2,938,259	
	Total Other		$17,459,788
6	Total of Lines 1 Through 5		$411,877,391

MDU RESOURCES GROUP, INC.
RECONCILIATION OF NET INCOME PER BOOKS WITH TAXABLE INCOME PER FEDERAL INCOME TAX RETURN
FOR THE 2010 TAX YEAR

M-1 Line No.			
7	Income Recorded on Books This Year not Included on This Return:		
	Other		
	Equity in Earnings of Subsidiary Companies	$203,307,628	
	Supplemental Income Security Plan-Cash Value Increase	1,416,159	
	Unrealized Gains/Losses on SISP	5,361,081	
	Allowance for Funds Used During Construction	4,268,299	
			$214,353,167
8	Deductions on This Return not Charged Against Book Income This Year:		
	Depreciation		$150,654,300
	Other		
	Bad Debt Expense per Return	893,996	
	Amortization per Return	3,126	
	Fuel & Purchased Power Deferral	1,009,699	
	Unrecovered Purchased Gas Cost	1,360,092	
	KESOP Incentive Compensation	721,133	
	State Income Tax Accrual per Return	(4,246,472)	
	Pension Expense per Return	3,128,268	
	Deferred Compensation for Directors	620,014	
	401(k) Dividend Deduction	3,515,904	
	Accrued Vacation Pay	38,669	
	Capitalized Interest Expense - Net	971,808	
	Medicare Part D Subsidy	277,709	
	Margin Sharing Adjustment	51,567	
	Rate Case Expense	246,549	
	Research and Development - CC&B	2,908,436	
	Casualty Losses-Storm Damages	1,138,111	
	Expenses for the Retirement of Assets	236,782	
	Property Insurance Adjustment	550,116	
	Restricted Stock Bonus Plan - Dividends	2,468,496	
			$15,894,003
9	Add Lines 7 and 8		380,901,470
10	Income (Form 1120, Page 1, Line 28) - Line 6 less Line 9		$30,975,921
	Less: Special Deductions		104,343,625
	Taxable Income (Form 1120, Page 1, Line 30)		($73,367,704)

MONTANA-DAKOTA UTILITIES CO.
DIFFERENCE IN BOOK AND TAX DEPRECIATION - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010

Tax Depreciation	
CIAC's - MACRS	($186,957)
Depreciation	28,679,769
Capitalized Interest Expense	(185,966)
Capitalized Tax Depreciation	(848,614)
Capitalized Inventory on Stores Inventory	(13,054)
Capitalized Property Taxes	(175,021)
Expenses for the Retirement of Assets	324,920
Reversal of Intercompany Gain-Airplanes	(157,524)
Gain on Disposition of Property	(1,574)
Retirement of Assets	(309,536)
Allowance For Funds Used During Construction-Not Yet in Service	168,474
Total Gas	$27,294,917
Book Depreciation	
Depreciation Expense	$8,693,793
Amortization Expense	498,206
Allowance For Funds Used During Construction	(218,137)
Total Book Depreciation	$8,973,862
Book over Tax Depreciation	($18,321,055)

MONTANA DAKOTA UTILITIES, CO.
CLAIMED ALLOWANCES FOR STATE INCOME TAXES
ACCRUAL AND PAYMENT RECORD
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010

	Reserve for State Inc. Tax Beg. Balance	(Payments)/ Refunds	Provisions		Reserve for State Inc. Tax End. Balance
January	$754,105	$432,266	$461,146		$1,647,517
February	1,647,517	(43)	494,030		2,141,504
March	2,141,504	(1,283,257)	224,888		1,083,135
April	1,083,135	7,943	74,553		1,165,631
May	1,165,631	(41)	61,479		1,227,069
June	1,227,069	(718,338)	(14,247)		494,484
July	494,484	6,287	28,293		529,064
August	529,064	3,258	(257,359)		274,963
September	274,963	352,956	(1,793,981)		(1,166,062)
October	(1,166,062)	(50,882)	(331,923)		(1,548,867)
November	(1,548,867)	552,518	64,813	1/	(931,536)
December	(931,536)	869,866	(1,959,720)		(2,021,390)
		$172,533	($2,948,028)		

1/ Provision for:

November Provision	$526,461
2009 Closing/Filing Adj.	(461,648)
	$64,813

MONTANA DAKOTA UTILITIES CO.
CLAIMED ALLOWANCES FOR STATE INCOME TAXES
ACCRUAL OF STATE INCOME TAXES - GAS UTILITY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010

	Minnesota	Montana	North Dakota	Total Gas
Federal Taxable Income	$518,063			($113,115)
Minnesota Adjustments				
Bonus Depreciation	2,992,010			50,875,000
Dividend Deduction	1,458			21,285
Preferred Stock Dividend	4,690			50,068
State Income Taxes	350,193			310,903
	3,866,414			51,144,141
Apportionment Factor	100.00%			5.8811%
Minnesota Taxable Income	$3,866,414			$3,007,838
Federal Taxable Income		($1,596,268)		(113,115)
Montana Adjustments				
Dividend Deduction		(18,931)		(72,001)
Preferred Stock Dividend		13,490		50,068
Fuel Tax Credit		(2,117)		(8,053)
State Income Taxes		(98,578)		310,903
		(1,702,404)		167,802
Apportionment Factor		100.00%		20.7781%
Montana Taxable Income		($1,702,404)		$34,866
Federal Taxable Income			$607,410	(113,115)
North Dakota Adjustments				
Dividend Deduction			8,377	21,285
Preferred Stock Dividend			14,868	50,068
State Income Taxes			59,290	310,903
Depreciation			(9,455)	(27,003)
			680,490	242,138
Apportionment Factor			100.00%	57.0113%
North Dakota Taxable Income			$ 680,490	$ 138,046
State Income Taxes				
Minnesota	$383,909	$0	$0	$299,770
Montana		(114,862)		2,353
North Dakota			43,551	8,782
Add: Allocated Adjustment	(33,716)	16,284	15,739	0
Total State Income Taxes	$350,193	($98,578)	$59,290	$310,905

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

Type of Tax	Total Company	Montana	Pro Forma Adjustments	Pro Forma	Adjustment No.
Ad Valorem					
Production	$224,065	$64,378	$1,578	$65,956	
Distribution	3,158,386	2,086,403	101,664	2,188,067	
General	217,734	87,648	5,288	92,936	
Common	366,005	265,647	5,857	271,504	
Intangible	16,559	0	0	0	
Total Ad Valorem Taxes	$3,982,749	$2,504,076	$114,387	$2,618,463	16
O&M Related Taxes - Other					
Payroll Taxes	$1,492,977	$428,471	$20,322	$448,793	17
Franchise	112,752				
Delaware Franchise	66,160	19,066		19,066	
Total O&M Related Taxes	$1,671,889	$447,537	$20,322	$467,859	
Revenue Taxes					
Montana PSC	$272,846	272,846	(154,920)	117,926	18
Montana Consumer Counsel	83,064	83,064	(12,309)	70,755	18
South Dakota	78,816				
Wyoming	46,999				
	$481,725	$355,910	($167,229)	$188,681	
Other					
Highway Use Tax	$719	$210		$210	
Secretary of State	992	286		286	
Total Other	$1,711	$496	$0	$496	
Total Taxes Other Than Income	$6,138,074	$3,308,019	($32,520)	$3,275,499	

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - MONTANA
ADJUSTMENT NO. 16

Function	Effective Tax Rate	Pro Forma Plant Balance 2/	Pro Forma Ad Valorem Tax	Per Books Ad Valorem Tax	Pro Forma Adjustment
Production	2.1213%	$3,109,209	$65,956	$64,378	$1,578
Distribution	2.9108%	75,170,640	2,188,067	2,086,403	101,664
General	1.4651%	6,343,335	92,936	87,648	5,288
Common	2.5071%	10,829,412	271,504	265,647	5,857
Intangible 1/	0.0000%	5,511,339	0	0	0
Total Ad Valorem Taxes		$100,963,935	$2,618,463	$2,504,076	$114,387

1/ General and Common intangible.
2/ Includes CWIP in service.

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Average Plant Balance @ 12/31/11	Ad Valorem Tax @ 12/31/11	Effective Tax Rate
Production	$3,034,769	$64,378	2.1213%
Distribution	71,677,695	2,086,403	2.9108%
General	5,982,213	87,648	1.4651%
Common	10,595,932	265,647	2.5071%
Intangible 1/	2,815,230	0	0.0000%
Total	$94,105,839	$2,504,076	

1/ General and common intangible.

MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 17

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Payroll Taxes	$1,492,978	$428,471	$448,793	$20,322

1/ Pro Forma labor expense multiplied by ratio of payroll taxes to 2011 labor expense.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO CONSUMER COUNSEL TAX
AND PSC TAX
GAS UTILITY - MONTANA
ADJUSTMENT NO. 18

Pro Forma Revenue 1/	$58,923,014
Miscellaneous Revenue 2/	39,741
Taxable Revenue	58,962,755
Consumer Counsel Tax @ 0.12% 2/	70,755
Per Books Consumer Counsel Tax	83,064
Pro Forma Adjustment	(12,309)
PSC Tax @ 0.2% 2/	117,926
Per Books PSC Tax	272,846
Pro Forma Adjustment	(154,920)
Pro Forma Adjustment	($167,229)

1/ Rule 38.5.164, Statement H, page 5.
2/ Includes revenues for seasonal reconnect fees, NSF check fees, and work for construction of others.
3/ Tax rate effective October 1, 2011.

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	43,247,501	8,562,896	4,871,709	14,395,676	27,830,281
Adjustments to Rate Base	512,333	(497,497)	(644,345)	2,132,722	990,880
Pro Forma Rate Base	43,759,834	8,065,399	4,227,364	16,528,398	28,821,161
Operating Income for Proposed Return	3,714,772	684,672	358,861	1,403,095	2,446,628
Current Operating Income	3,628,300	(1,247,118)	4,202,218	(1,501,802)	1,453,298
Adjustment to Operating Income	(2,001,276)	(174,984)	(544,588)	(653,490)	(1,373,062)
Required Increase in Operating Income	2,087,748	2,106,774	(3,298,769)	3,558,387	2,366,392
Related Taxes for Increase					
Federal Income	1,356,673	1,369,036	(2,143,625)	2,312,333	1,537,744
Revenue Tax	11,057	11,158	(17,472)	18,847	12,533
Total Increase in Revenue	3,455,478	3,486,968	(5,459,866)	5,889,567	3,916,669
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	62,378,492	10,972,868	17,437,882	11,235,835	39,646,585
Less Cost of Gas	38,854,572	7,482,150	16,034,347	0	23,516,497
Net Distribution Cost of Service	23,523,920	3,490,718	1,403,535	11,235,835	16,130,088
Pro Forma Rate of Return	3.720%	-17.632%	86.523%	-13.040%	0.278%
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		$0.572			
Customer Cost Per Month				$13.350	

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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 Demand	Small Firm General Energy	Small Firm General Customer	Total Small Firm General	Large Firm General Demand	Large Firm General Energy	Large Firm General Customer	Total Large Firm General
Rate Base	43,247,501	1,785,799	856,463	1,533,212	4,175,474	3,600,482	2,188,974	3,948,874	9,738,330
Adjustments to Rate Base	512,333	(103,608)	(111,443)	199,056	(15,995)	(208,910)	(291,271)	96,576	(403,605)
Pro Forma Rate Base	43,759,834	1,682,191	745,020	1,732,268	4,159,479	3,391,572	1,897,703	4,045,450	9,334,725
Operating Income for Proposed Return	3,714,772	142,801	63,245	147,052	353,098	287,911	161,096	343,418	792,425
Current Operating Income	3,628,300	(260,331)	816,861	10,073	566,603	(524,561)	2,144,245	(531,394)	1,088,290
Adjustment to Operating Income	(2,001,276)	(36,746)	5,483	(62,642)	(93,905)	(73,776)	(174,789)	(144,835)	(393,400)
Required Increase in Operating Income	2,087,748	439,878	(759,099)	199,621	(119,600)	886,248	(1,808,360)	1,019,647	97,535
Related Taxes for Increase									
Federal Income	1,356,673	285,844	(493,283)	129,719	(77,720)	575,907	(1,175,119)	662,593	63,381
Revenue Tax	11,057	2,330	(4,020)	1,057	(633)	4,694	(9,578)	5,400	516
Total Increase in Revenue	3,455,478	728,052	(1,256,402)	330,397	(197,953)	1,466,849	(2,993,057)	1,687,640	161,432
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	62,378,492	2,279,243	3,023,455	1,147,463	6,450,161	4,605,944	7,906,833	2,257,324	14,770,101
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	23,523,920	728,829	257,361	1,147,463	2,133,653	1,468,422	651,817	2,257,324	4,377,563
Pro Forma Rate of Return	3.720%	-17.660%	110.379%	-3.035%	11.364%	-17.642%	103.781%	-16.716%	7.444%
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		$0.651				$0.545			
Customer Cost Per Month				$14.610				$87.370	

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

	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Rate Base	43,247,501	333,422	166,595	209,788	709,805	736,060	0	57,551	793,611
Adjustments to Rate Base	512,333	(17,349)	(21,646)	3,652	(35,343)	(24,201)	0	597	(23,604)
Pro Forma Rate Base	43,759,834	316,073	144,949	213,440	674,462	711,859	0	58,148	770,007
Operating Income for Proposed Return	3,714,772	26,831	12,305	18,119	57,255	60,430	0	4,936	65,366
Current Operating Income	3,628,300	(57,913)	395,071	(18,609)	318,549	(125,270)	313,691	13,139	201,560
Adjustment to Operating Income	(2,001,276)	(12,044)	(23,107)	(11,491)	(46,642)	(30,087)	(55,548)	(8,632)	(94,267)
Required Increase in Operating Income	2,087,748	96,788	(359,659)	48,219	(214,652)	215,787	(258,143)	429	(41,927)
Related Taxes for Increase									
Federal Income	1,356,673	62,895	(233,716)	31,334	(139,487)	140,224	(167,748)	279	(27,245)
Revenue Tax	11,057	513	(1,905)	255	(1,137)	1,143	(1,367)	2	(222)
Total Increase in Revenue	3,455,478	160,196	(595,280)	79,808	(355,276)	357,154	(427,258)	710	(69,394)
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	62,378,492	246,066	619,361	166,808	1,032,235	357,154	89,746	32,510	479,410
Less Cost of Gas	38,854,572	91,968	537,061	0	629,029	0	0	0	0
Net Distribution Cost of Service	23,523,920	154,098	82,300	166,808	403,206	357,154	89,746	32,510	479,410
Pro Forma Rate of Return	3.720%	-22.133%	256.617%	-14.102%	40.315%	-21.824%	0.000%	7.751%	13.934%
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		$0.170				$0.085			
Customer Cost Per Month				$315.920				$541.830	

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Report
Twelve Months Ended December 31, 2011
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Operating Income and Rate of Return	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Sales Revenues	73,742,148	44,762,102	8,329,512	17,935,809	1,971,742	742,983
Adjustments to Sales Revenues	(14,819,134)	(9,032,186)	(1,681,398)	(3,327,140)	(584,231)	(194,179)
Total Sales Revenues	58,923,014	35,729,916	6,648,114	14,608,669	1,387,511	548,804
Other Revenues	368,826	249,962	33,222	71,684	6,557	7,401
Adjustments to Other Revenues	47,286	30,520	4,363	10,136	996	1,271
Total Other Revenues	416,112	280,482	37,585	81,820	7,553	8,672
Total Operating Revenues	59,339,126	36,010,398	6,685,699	14,690,489	1,395,064	557,476
Operating Expense						
Cost of Gas	52,735,031	31,910,290	6,052,454	13,503,155	1,177,123	92,009
Adj. to Cost of Gas	(13,880,459)	(8,393,793)	(1,735,946)	(3,110,617)	(548,094)	(92,009)
Total Cost of Gas	38,854,572	23,516,497	4,316,508	10,392,538	629,029	0
Other O&M Expense	10,869,310	7,814,348	943,899	1,735,185	160,012	215,866
Adjustments to Other O&M	247,767	168,722	21,675	46,461	4,457	6,452
Total Other O&M Expense	11,117,077	7,983,070	965,574	1,781,646	164,469	222,318
Total Operation & Maintenance Expense	49,971,649	31,499,567	5,282,082	12,174,184	793,498	222,318
Depreciation Expense	3,011,298	1,992,602	263,267	637,084	60,078	58,267
Adjustment to Depreciation Expense	1,412,304	992,324	127,257	240,768	22,940	29,015
Total Depreciation Expense	4,423,602	2,984,926	390,524	877,852	83,018	87,282
Taxes Other Than Income Taxes	3,308,019	2,149,862	311,685	700,157	67,983	78,332
Adjustment to Taxes Other Than Income	(32,520)	(12,984)	(6,517)	(13,648)	(1,235)	1,864
Total Taxes Other Than Income	3,275,499	2,136,878	305,168	686,509	66,748	80,196
Current Income Taxes - Fed. & State	(2,930,185)	(2,579,718)	(93,115)	(408,902)	124,736	26,814
Adjustment to Current Income Taxes	(362,889)	(281,316)	22,973	(48,055)	(12,238)	(44,253)
Total Current Income Taxes	(3,293,074)	(2,861,034)	(70,142)	(456,957)	112,498	(17,439)

MONTANA-DAKOTA UTILITIES CO.
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Summary Report
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Operating Income and Rate of Return	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Deferred Income Taxes	3,489,201	2,271,382	317,941	752,524	69,818	77,536
Adjustment to Deferred Income Tax	(154,775)	(101,556)	(12,572)	(38,513)	(2,423)	289
Total Deferred Income Taxes	3,334,426	2,169,826	305,369	714,011	67,395	77,825
Total Operating Expenses	57,712,102	35,930,163	6,213,001	13,995,599	1,123,157	450,182
Pro Forma Operating Income	1,627,024	80,235	472,698	694,890	271,907	107,294
Rate Base	43,247,501	27,830,281	4,175,474	9,738,330	709,805	793,611
Adjustment to Rate Base	512,333	990,880	(15,995)	(403,605)	(35,343)	(23,604)
Total Pro Forma Rate Base	43,759,834	28,821,161	4,159,479	9,334,725	674,462	770,007
Pro Forma Rate of Return	3.718%	0.278%	11.364%	7.444%	40.315%	13.934%

MONTANA-DAKOTA UTILITIES CO.
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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Rate Base						
Gas Plant in Service						
Production Plant	3	3,034,769	0	1,826,714	0	1,826,714
Distribution Plant						
Land	13	15,962	9,002	0	0	9,002
Rights of Way	13	22,846	12,886	0	0	12,886
Structures & Improvements	13	168,491	95,030	0	0	95,030
Direct to Small IT	Direct	24,611	0	0	0	0
Direct to Large IT	Direct	2,062	0	0	0	0
Mains - $28,623,324						
Demand Related 100%	5	28,623,324	16,143,803	0	0	16,143,803
Meas. & Reg. Equip. - General	13	576,181	324,971	0	0	324,971
Meas. & Reg. Equip. - City Gate	13	22,301	12,578	0	0	12,578
Direct to Firm General	Direct	3,913	0	0	0	0
Direct to Small IT	Direct	83,476	0	0	0	0
Direct to Large IT	Direct	18,532	0	0	0	0
Services	10	20,458,685	0	0	14,522,038	14,522,038
Meters	10	18,117,820	0	0	12,860,438	12,860,438
Service Regulators	10	1,979,814	0	0	1,405,317	1,405,317
Direct to Firm General	Direct	27,085	0	0	0	0
Direct to Small IT	Direct	12,521	0	0	0	0
Ind. Meas. & Reg. Station Equipment	13	146,005	82,348	0	0	82,348
Direct to Small IT	Direct	8,161	0	0	0	0
Direct to Large IT	Direct	33,659	0	0	0	0
Property on Customer Premise	13	148,674	83,854	0	0	83,854
Cathodic Protection & Other Equipment	13	1,183,575	667,546	0	0	667,546
Distribution Plant		71,677,698	17,432,018	0	28,787,793	46,219,811
General Plant	15	5,982,213	1,454,874	0	2,402,626	3,857,500
Intangible Plant - General	15	55,760	13,561	0	22,394	35,955
Common Plant	15	10,595,932	2,576,931	0	4,255,627	6,832,558
Intangible Plant - Common	15	2,759,471	671,103	0	1,108,284	1,779,387
Gas Plant Leased to Others	15	0	0	0	0	0
Total Gas Plant in Service		94,105,843	22,148,487	1,826,714	36,576,724	60,551,925

MONTANA-DAKOTA UTILITIES CO.
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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Less: Accumulated Depreciation						
Production Plant	3	50,797	0	30,577	0	30,577
Distribution Plant						
Rights of Way	13	14,219	8,020	0	0	8,020
Structures & Improvements	17	164,245	79,975	0	0	79,975
Mains	13	19,340,970	10,908,475	0	0	10,908,475
Meas. & Reg. Equip. - General	18	457,800	258,204	0	0	258,204
Meas. & Reg. Equip. - City Gate	19	126,357	12,395	0	0	12,395
Services	10	15,458,953	0	0	10,973,115	10,973,115
Meters	10	5,457,201	0	0	3,873,645	3,873,645
Service Regulators	20	887,096	0	0	617,331	617,331
Ind. Meas. & Reg. Station Equipment	21	67,888	29,764	0	0	29,764
Property on Customer Premise	13	143,163	80,746	0	0	80,746
Cathodic Protection & Other Equipment	13	775,459	437,366	0	0	437,366
Distribution Plant		42,893,351	11,814,945	0	15,464,091	27,279,036
General Plant	15	3,177,682	772,812	0	1,276,247	2,049,059
Intangible Plant - General	15	55,760	13,561	0	22,394	35,955
Common Plant	15	2,977,057	724,020	0	1,195,671	1,919,691
Intangible Plant - Common	15	2,104,538	511,824	0	845,242	1,357,066
Gas Plant Leased to Others	15	0	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		51,259,185	13,837,162	30,577	18,803,645	32,671,384
Net Gas Plant in Service		42,846,658	8,311,325	1,796,137	17,773,079	27,880,541
CWIP in Service	15	500,474	121,715	0	201,006	322,721
Total Gas Plant in Service		43,347,132	8,433,040	1,796,137	17,974,085	28,203,262
Additions						
Materials & Supplies	15	533,337	129,708	0	214,203	343,911
Prepaid Insurance	24	25,908	5,026	1,086	10,746	16,858
Gas in Underground Storage	33	7,134,766	1,373,928	2,944,346	0	4,318,274
Prepaid Demand/Commodity	33	1,149,982	221,450	474,571	0	696,021
Other	24	128,892	25,002	5,403	53,465	83,870
Unamortized Loss on Debt	24	584,820	113,442	24,516	242,588	380,546
Total Additions		9,557,705	1,868,556	3,449,922	521,002	5,839,480
Total Before Deductions		52,904,837	10,301,596	5,246,059	18,495,087	34,042,742

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Deductions						
Accumulated Deferred Income Tax	24	(8,925,996)	(1,731,450)	(374,179)	(3,702,562)	(5,808,191)
Accumulated Investment Tax Credit	24	(4,084)	(792)	(171)	(1,694)	(2,657)
Customer Advances For Construction	Direct	(727,256)	(6,458)		(395,155)	(401,613)
Total Deductions		(9,657,336)	(1,738,700)	(374,350)	(4,099,411)	(6,212,461)
Total Rate Base		43,247,501	8,562,896	4,871,709	14,395,676	27,830,281
Income Statement						
Gas Operating Revenues						
Retail Sales & Transportation						
Residential	Direct	45,522,909	7,485,900	32,701,866	5,335,143	45,522,909
Firm General	Direct	26,717,947	0	0	0	0
Small Interruptible	Direct	2,001,287	0	0	0	0
Large Interruptible	Direct	754,669	0	0	0	0
Total Sales & Transportation Revenues		74,996,812	7,485,900	32,701,866	5,335,143	45,522,909
Other Operating Revenue						
Miscellaneous						
Reconnect Fees	11	1,480	0	0	1,317	1,317
NSF Check Fees	11	28,024	0	0	24,932	24,932
Miscellaneous	24	15,830	3,071	664	6,566	10,301
Rent From Gas Property	24	244,710	47,468	10,258	101,508	159,234
Other Gas Revenues						
Miscellaneous	31	42,705	5,129	1,319	24,254	30,702
Transport and Penalty Revenue - Net	24	36,077	6,998	1,512	14,966	23,476
Total Other Operating Revenue		368,826	62,666	13,753	173,543	249,962
Unbilled Revenue	26	(1,254,664)	(159,399)	(487,568)	(113,840)	(760,807)
Total Operating Revenues		74,110,974	7,389,167	32,228,051	5,394,846	45,012,064
Operation & Maintenance Expenses						
Cost of Purchased Gas	Direct	52,735,031	7,482,150	24,428,140	0	31,910,290
Production Expense						
Production Expense	3	188,558	0	113,498	0	113,498
Other Gas Supply Expenses	3	73,609	0	44,307	0	44,307
Total Production Expense		262,167	0	157,805	0	157,805

MONTANA-DAKOTA UTILITIES CO.
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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Distribution Expenses						
Operation						
Load Dispatch	1	74,482	0	30,249	0	30,249
Mains and Services	22	1,138,365	374,425	0	336,811	711,236
Measuring Stations - General	18	34,815	19,636	0	0	19,636
Measuring Stations - Industrial	21	14,521	6,366	0	0	6,366
Measuring Stations - City Gate	19	0	0	0	0	0
Meters & House Regulators	16	267,551	0	0	189,539	189,539
Customer Installations	10	538,992	0	0	382,588	382,588
Other Gas Distribution	27	832,223	161,087	12,169	365,655	538,911
Rents	27	33,379	6,461	488	14,666	21,615
Supervision & Engineering	27	514,850	99,655	7,528	226,210	333,393
Total Operation Expense		3,449,178	667,630	50,434	1,515,469	2,233,533
Maintenance						
Structures & Improvements	17	1,179	573	0	0	573
Mains	13	138,093	77,887	0	0	77,887
Measuring Stations - General	18	28,158	15,881	0	0	15,881
Measuring Stations - Industrial	21	15,721	6,892	0	0	6,892
Measuring Stations - City Gate	19	0	0	0	0	0
Services	10	155,111	0	0	110,101	110,101
Meters & House Regulators	16	284,028	0	0	201,214	201,214
Other Equipment	28	120,738	19,641	0	60,402	80,043
Supervision & Engineering	28	130,671	21,257	0	65,373	86,630
Total Maintenance Expense		873,699	142,131	0	437,090	579,221
Total Distribution Expenses		4,322,877	809,761	50,434	1,952,559	2,812,754
Customer Accounts	8	96,853	0	0	86,114	86,114
Meter Reading	10	230,640	0	0	163,714	163,714
Customer Records & Collection	8	1,376,127	0	0	1,223,552	1,223,552
Uncollectible Accounts	11	173,361	0	0	154,236	154,236
Miscellaneous Customer Accounts	8	71,102	0	0	63,218	63,218
Customer Service & Information	8	89,100	0	0	79,221	79,221
Sales Expenses	8	119,573	0	0	106,315	106,315
Administration & General Expenses	30	4,127,510	495,757	127,489	2,344,173	2,967,419
Total Gas O&M Expenses		63,604,341	8,787,668	24,763,868	6,173,102	39,724,638
O&M Excl. Cost of Gas and A&G		6,741,800	809,761	208,239	3,828,929	4,846,929

MONTANA-DAKOTA UTILITIES CO.
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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
O&M Excl. Cost of Gas		10,869,310	1,305,518	335,728	6,173,102	7,814,348
Depreciation Expense						
Production Plant	3	101,594	0	61,152	0	61,152
Distribution Plant						
Rights of Way	13	317	180	0	0	180
Structures & Improvements	17	3,533	1,720	0	0	1,720
Mains	13	590,840	333,238	0	0	333,238
Meas. & Reg. Equip. - General	18	18,947	10,686	0	0	10,686
Meas. & Reg. Equip. - City Gate	19	3,603	353	0	0	353
Services	10	1,160,453	0	0	823,716	823,716
Meters	10	519,807	0	0	368,970	368,970
Service Regulators	20	30,901	0	0	21,504	21,504
Ind. Meas. & Reg. Station Equipment	21	4,563	1,999	0	0	1,999
Property on Customer Premise	13	0	0	0	0	0
Cathodic Protection & Other Equipment	13	34,801	19,628	0	0	19,628
Total Distribution Plant		2,469,359	367,804	61,152	1,214,190	1,643,146
General Plant	15	115,122	27,998	0	46,235	74,233
Amort. of Intangible Plant - General	15	0	0	0	0	0
Common Plant	15	315,830	76,810	0	126,845	203,655
Amort. of Intangible Plant - Common	15	110,987	26,992	0	44,576	71,568
Gas Plant Leased to Others	15	0	0	0	0	0
Total Depreciation Expense		3,011,298	499,604	61,152	1,431,846	1,992,602
Taxes Other Than Income						
Ad Valorem Taxes-Production	3	64,378	0	38,751	0	38,751
Ad Valorem Taxes-Other	15	2,439,698	593,335	0	979,851	1,573,186
Other Taxes - Payroll, Franchise, Other	31	448,033	53,813	13,839	254,456	322,108
Other Taxes - Revenue	26	355,910	45,217	138,307	32,293	215,817
Total Taxes Other Than Income Taxes		3,308,019	692,365	190,897	1,266,600	2,149,862
Total Operating Expense		69,923,658	9,979,637	25,015,917	8,871,548	43,867,102
Interest Expense	24	1,269,714	246,297	53,227	526,687	826,211
Taxable Income Before Adjustments		2,917,602	(2,836,767)	7,158,907	(4,003,389)	318,751

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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Deductions						
Unrecovered Purchased Gas Cost	33	52,394	10,089	21,622	0	31,711
Other Income Tax Charges	24	6,128,908	1,188,876	256,925	2,542,313	3,988,114
Preferred Dividend Paid Deduction	24	13,836	2,684	580	5,740	9,004
Total Deductions		6,195,138	1,201,649	279,127	2,548,053	4,028,829
Taxable Income (Before State Income Tax)		(3,277,536)	(4,038,416)	6,879,780	(6,551,442)	(3,710,078)
Less: State Income Tax	35	(386,615)	(476,368)	811,533	(772,802)	(437,637)
Federal Taxable Income		(2,890,921)	(3,562,048)	6,068,247	(5,778,640)	(3,272,441)
Federal Income Tax						
@ Current Rate of 35%	35.00%	(1,011,822)	(1,246,717)	2,123,887	(2,022,524)	(1,145,354)
State Income Taxes	35	(386,615)	(476,368)	811,533	(772,802)	(437,637)
Credits and Adjustments	40	29,134	5,651	1,313	11,981	18,945
Rounding & Prior Year's Adjustments - Federal	24	(1,236,864)	(239,925)	(51,849)	(513,059)	(804,833)
Federal and State Income Taxes		(2,606,167)	(1,957,359)	2,884,884	(3,296,404)	(2,368,879)
Rounding & Prior Year's Adjustment - State	24	(324,018)	(62,852)	(13,583)	(134,404)	(210,839)
Federal & State Income Taxes		(2,930,185)	(2,020,211)	2,871,301	(3,430,808)	(2,579,718)
Deferred Income Taxes						
Unrecovered Purchased Gas Cost	33	(20,643)	(3,975)	(8,518)	0	(12,493)
Other Deferred Income Tax Chgs	24	2,206,874	428,086	92,512	915,427	1,436,025
Closing/Filing & Out of Period	24	1,302,970	252,748	54,621	540,481	847,850
Total Deferred Income Taxes		3,489,201	676,859	138,615	1,455,908	2,271,382
Total Operating Expenses		70,482,674	8,636,285	28,025,833	6,896,648	43,558,766
Total Operating Income		3,628,300	(1,247,118)	4,202,218	(1,501,802)	1,453,298

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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Summary of Pro Forma Rate Base Adjustments						
Plant						
Plant Additions - Adj. A						
Production	3	74,440	0	44,807	0	44,807
Distribution						
Mains-Demand Related	5	957,339	539,948	0	0	539,948
Meas. & Reg. Equip. General	13	14,164	7,989	0	0	7,989
Services	10	1,324,687	0	0	940,292	940,292
Positive Meters	10	573,629	0	0	407,175	407,175
Service Regulators	10	131,754	0	0	93,522	93,522
Cathodic Protection Equip	13	109,023	61,490	0	0	61,490
Other Distribution Equipment	13	(118)	(66)	0	0	(66)
Total Distribution Plant Additions		3,110,478	609,361	0	1,440,989	2,050,350
General	15	309,554	75,284	0	124,325	199,609
Common	15	394,348	95,905	0	158,382	254,287
Common Intangible	8	2,468,802	0	0	2,195,079	2,195,079
Total Plant Additions - Adj. A		6,357,622	780,550	44,807	3,918,775	4,744,132
Accumulated Reserve for Depreciation						
Plant Additions - Adj. B						
Production	3	102,565	0	61,737	0	61,737
Distribution	23	2,607,909	629,114	0	1,054,096	1,683,210
General	15	(33,342)	(8,109)	0	(13,390)	(21,499)
Common	15	360,927	87,777	0	144,960	232,737
Common Intangible	8	164,587	0	0	146,339	146,339
Total Accumulated Reserve - Adj. B		3,202,646	708,782	61,737	1,332,005	2,102,524
Net Adjustment to Plant		3,154,976	71,768	(16,930)	2,586,770	2,641,608
Additions						
Materials and Supplies - Adj. C	15	99,695	24,246	0	40,039	64,285
Gas in Underground Storage - Adj. D	33	(855,502)	(164,742)	(353,046)	0	(517,788)
Prepaid Insurance - Adj. E	24	93,808	18,197	3,934	38,910	61,041
Prepaid Demand and Commodity-Adj. F	33	(642,915)	(123,805)	(265,314)	0	(389,119)
Unamortized Loss on Debt - Adj. G	24	(53,806)	(10,437)	(2,256)	(22,318)	(35,011)
Provision for Pensions & Benefits - Adj. H	24	1,268,837	246,127	53,190	526,321	825,638

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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
Provision for Injuries & Damages - Adj. I	24	(109,736)	(21,286)	(4,600)	(45,520)	(71,406)
Deferred FAS 106 Costs - Adj. J	24	273,775	53,106	11,477	113,563	178,146
Total		74,156	21,406	(556,615)	650,995	115,786
Deductions						
Accumulated Def. Inc. Tax						
Plant Additions - Adj. K	41	1,887,637	430,820	35,165	760,880	1,226,865
Normalization - Adj L	24	(25,349)	(4,917)	(1,063)	(10,515)	(16,495)
Def. FAS 106 - Adj. J	24	105,855	20,534	4,437	43,910	68,881
Unamortized Loss on Debt - Adj. G	24	(31,526)	(6,115)	(1,322)	(13,077)	(20,514)
Pension - Adj. H	24	846,179	164,140	35,472	351,000	550,612
Injuries and Damages - Adj. I	24	(41,583)	(8,066)	(1,743)	(17,250)	(27,059)
Investment Tax Credits - Adj. M	24	(3,488)	(677)	(146)	(1,447)	(2,270)
Customer Advances for Construction - Adj. N	Direct	(20,926)	(5,048)		(8,458)	(13,506)
Total		2,716,799	590,671	70,800	1,105,043	1,766,514
Total Pro Forma Adjustments - Rate Base		512,333	(497,497)	(644,345)	2,132,722	990,880
Pro Forma Adjustments - Operating Income						
Pro Forma Revenue Adjustments						
Revenue Adjustments - Adj. No. 1-3 to Proforma						
Residential	Direct	(9,792,993)	0	(9,804,118)	11,125	(9,792,993)
Firm General	Direct	(5,461,164)				0
Small Interruptible	Direct	(613,776)				0
Large Interruptible	Direct	(205,865)				0
Total Retail Sales Adjustment		(16,073,798)	0	(9,804,118)	11,125	(9,792,993)
Unbilled Revenue	26	1,254,664	159,399	487,568	113,840	760,807
Total		(14,819,134)	159,399	(9,316,550)	124,965	(9,032,186)
Other Revenue - Adj. No. 4	23	47,286	11,407	0	19,113	30,520
Total Pro Forma Revenue Adjustments		(14,771,848)	170,806	(9,316,550)	144,078	(9,001,666)

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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
OPERATION & MAINTENANCE EXPENSES						
Cost of Gas - Adj. No. 5	Direct	(13,880,459)	0	(8,393,793)		(8,393,793)
Labor Expense - Adj. No. 6						
Other Gas Supply	30	2,495	299	77	1,417	1,793
Production	3	1,334	0	803	0	803
Distribution	29	160,710	30,104	1,875	72,590	104,569
Customer Accounting	8	50,020	0	0	44,474	44,474
Customer Service	8	2,645	0	0	2,353	2,353
Sales	8	4,111	0	0	3,656	3,656
A&G	30	48,407	5,814	1,495	27,494	34,803
Total -Labor Expense - Adj. No. 6		269,722	36,217	4,250	151,984	192,451
Benefits Expense - Adj. No. 7	30	(75,501)	(9,068)	(2,332)	(42,882)	(54,282)
Vehicles and Work Equip. - Adj. No. 8	30	(6,716)	(807)	(207)	(3,815)	(4,829)
Company Consumption - Adj. No. 9	30	(8,120)	(975)	(251)	(4,613)	(5,839)
Uncollectible Accounts - Adj. No. 10	11	(14,963)	0	0	(13,312)	(13,312)
Advertising - Adj. No. 11	8	(31,656)	0	0	(28,146)	(28,146)
Insurance Expense - Adj. No. 12	30	13,839	1,662	427	7,862	9,951
Industry Dues - Adj. No. 13	30	(7,138)	(857)	(220)	(4,056)	(5,133)
Regulatory Commission Expense - Adj. No. 14	30	108,300	13,008	3,345	61,508	77,861
Total		53,546	12,031	3,094	15,428	30,553
Total Adjustments to O&M		(13,632,692)	39,180	(8,388,781)	124,530	(8,225,071)
DEPRECIATION EXPENSE						
Average Annual Depreciation - Adj. No. 15						
Production Plant	3	1,943	0	1,169	0	1,169
Distribution Plant	23	1,082,553	261,148	0	437,558	698,706
General Plant	41	(4,128)	(942)	(77)	(1,665)	(2,684)
Common	8	331,936	0	0	295,133	295,133
Total Average Annual Depreciation Adj. 15		1,412,304	260,206	1,092	731,026	992,324

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	Allocation Factor	Total Montana	Residential Demand	Residential Energy	Residential Customer	Total Residential
TAXES OTHER THAN INCOME						
Ad Valorem Taxes - Adj. No. 16						
Production Plant	3	1,578	0	950	0	950
Distribution Plant	23	101,664	24,525	0	41,092	65,617
General Plant	41	5,288	1,207	99	2,129	3,435
Common Plant	41	5,857	1,337	109	2,363	3,809
Total Ad Valorem Taxes		114,387	27,069	1,158	45,584	73,811
Payroll Taxes - Adj. No. 17	31	20,322	2,441	628	11,541	14,610
Montana Consumer Counsel & PSC Tax - Adj. 18	26	(167,229)	(21,246)	(64,986)	(15,173)	(101,405)
Total Adjustments to Taxes Other than Income		(32,520)	8,264	(63,200)	41,952	(12,984)
CURRENT INCOME TAXES						
Interest Annualization - Adj. No. 19	24	(51,878)	(10,063)	(2,175)	(21,520)	(33,758)
Tax Depreciation on Plant Additions - Adj. No. 20	41	2,817,177	642,972	52,481	1,135,567	1,831,020
Other Tax Deductions - Adj. No. 21	24	(400,022)	(77,596)	(16,769)	(165,931)	(260,296)
		2,365,277	555,313	33,537	948,116	1,536,966
Net Adjustments to Operating Income		(4,884,217)	(692,157)	(899,198)	(1,701,546)	(3,292,901)
Income Taxes on Pro Forma Adj. - Adj. No. 22	(Calculated)	(1,923,771)	(272,623)	(354,172)	(670,196)	(1,296,991)
0.393875						
Elimination of Closing/Filing&Res. - Adj. No. 23	24	1,560,882	302,777	65,432	647,466	1,015,675
Total Adjustments to Current Income Taxes		(362,889)	30,154	(288,740)	(22,730)	(281,316)
DEFERRED INCOME TAXES						
Plant Additions - Adj. No. 20	41	1,109,616	253,251	20,671	447,269	721,191
Elimination of Closing/Filing - Adj. No. 23	24	(1,302,970)	(252,748)	(54,621)	(540,481)	(847,850)
Other Tax Deductions	24	38,579	7,483	1,617	16,003	25,103
Total Adjustments to Deferred Income Taxes		(154,775)	7,986	(32,333)	(77,209)	(101,556)
Total Adjustments:		(2,001,276)	(174,984)	(544,588)	(653,490)	(1,373,062)

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Rate Base										
Gas Plant in Service										
Production Plant	3	3,034,769	0	335,298	0	335,298	0	807,272	0	807,272
Distribution Plant										
Land	13	15,962	1,880	0	0	1,880	3,788	0	0	3,788
Rights of Way	13	22,846	2,690	0	0	2,690	5,421	0	0	5,421
Structures & Improvements	13	168,491	19,840	0	0	19,840	39,983	0	0	39,983
Direct to Small IT	Direct	24,611	0	0	0	0	0	0	0	0
Direct to Large IT	Direct	2,062	0	0	0	0	0	0	0	0
Mains - $28,623,324										
Demand Related 100%	5	28,623,324	3,370,364	0	0	3,370,364	6,792,282	0	0	6,792,282
Meas. & Reg. Equip. - General	13	576,181	67,845	0	0	67,845	136,727	0	0	136,727
Meas. & Reg. Equip. - City Gate	13	22,301	2,626	0	0	2,626	5,292	0	0	5,292
Direct to Firm General	Direct	3,913	3,913	0	0	3,913	0	0	0	0
Direct to Small IT	Direct	83,476	0	0	0	0	0	0	0	0
Direct to Large IT	Direct	18,532	0	0	0	0	0	0	0	0
Services	10	20,458,685	0	0	1,490,682	1,490,682	0	0	4,055,391	4,055,391
Meters	10	18,117,820	0	0	1,320,119	1,320,119	0	0	3,591,377	3,591,377
Service Regulators	10	1,979,814	0	0	144,255	144,255	0	0	392,446	392,446
Direct to Firm General	Direct	27,085		0	27,085	27,085	0	0	0	0
Direct to Small IT	Direct	12,521	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	13	146,005	17,192	0	0	17,192	34,647	0	0	34,647
Direct to Small IT	Direct	8,161	0	0	0	0	0	0	0	0
Direct to Large IT	Direct	33,659	0	0	0	0	0	0	0	0
Property on Customer Premise	13	148,674	17,506	0	0	17,506	35,280	0	0	35,280
Cathodic Protection & Other Equipment	13	1,183,575	139,365	0	0	139,365	280,861	0	0	280,861
Distribution Plant		71,677,698	3,643,221	0	2,982,141	6,625,362	7,334,281	0	8,039,214	15,373,495
General Plant	15	5,982,213	304,063	0	248,889	552,952	612,118	0	670,952	1,283,070
Intangible Plant - General	15	55,760	2,834	0	2,320	5,154	5,706	0	6,254	11,960
Common Plant	15	10,595,932	538,568	0	440,842	979,410	1,084,208	0	1,188,417	2,272,625
Intangible Plant - Common	15	2,759,471	140,258	0	114,807	255,065	282,357	0	309,496	591,853
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Total Gas Plant in Service		94,105,843	4,628,944	335,298	3,788,999	8,753,241	9,318,670	807,272	10,214,333	20,340,275

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			Firm General-Meter < 500 cubic feet				Firm General > 500 cubic feet			
	Allocation Factor	Total Montana	Demand	Energy	Customer	Total Small Firm General	Demand	Energy	Customer	Total Large Firm General
Less: Accumulated Depreciation										
Production Plant	3	50,797	0	5,612	0	5,612	0	13,512	0	13,512
Distribution Plant										
Rights of Way	13	14,219	1,674	0	0	1,674	3,374	0	0	3,374
Structures & Improvements	17	164,245	16,697	0	0	16,697	33,649	0	0	33,649
Mains	13	19,340,970	2,277,377	0	0	2,277,377	4,589,590	0	0	4,589,590
Meas. & Reg. Equip. - General	18	457,800	53,906	0	0	53,906	108,635	0	0	108,635
Meas. & Reg. Equip. - City Gate	19	126,357	6,444	0	0	6,444	5,215	0	0	5,215
Services	10	15,458,953	0	0	1,126,386	1,126,386	0	0	3,064,327	3,064,327
Meters	10	5,457,201	0	0	397,628	397,628	0	0	1,081,745	1,081,745
Service Regulators	20	887,096	0	0	75,267	75,267	0	0	172,395	172,395
Ind. Meas. & Reg. Station Equipment	21	67,888	6,214	0	0	6,214	12,523	0	0	12,523
Property on Customer Premise	13	143,163	16,857	0	0	16,857	33,972	0	0	33,972
Cathodic Protection & Other Equipment	13	775,459	91,309	0	0	91,309	184,016	0	0	184,016
Distribution Plant		42,893,351	2,470,478	0	1,599,281	4,069,759	4,970,974	0	4,318,467	9,289,441
General Plant	15	3,177,682	161,515	0	132,207	293,722	325,150	0	356,402	681,552
Intangible Plant - General	15	55,760	2,834	0	2,320	5,154	5,706	0	6,254	11,960
Common Plant	15	2,977,057	151,317	0	123,860	275,177	304,622	0	333,900	638,522
Intangible Plant - Common	15	2,104,538	106,969	0	87,559	194,528	215,343	0	236,040	451,383
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		51,259,185	2,893,113	5,612	1,945,227	4,843,952	5,821,795	13,512	5,251,063	11,086,370
Net Gas Plant in Service		42,846,658	1,735,831	329,686	1,843,772	3,909,289	3,496,875	793,760	4,963,270	9,253,905
CWIP in Service	15	500,474	25,438	0	20,822	46,260	51,210	0	56,132	107,342
Total Gas Plant in Service		43,347,132	1,761,269	329,686	1,864,594	3,955,549	3,548,085	793,760	5,019,402	9,361,247
Additions										
Materials & Supplies	15	533,337	27,108	0	22,189	49,297	54,573	0	59,818	114,391
Prepaid Insurance	24	25,908	1,050	199	1,115	2,364	2,114	480	3,001	5,595
Gas in Underground Storage	33	7,134,766	284,699	507,931	0	792,630	576,135	1,332,220	0	1,908,355
Prepaid Demand/Commodity	33	1,149,982	45,888	81,868	0	127,756	92,861	214,727	0	307,588
Other	24	128,892	5,222	992	5,546	11,760	10,519	2,388	14,931	27,838
Unamortized Loss on Debt	24	584,820	23,693	4,500	25,166	53,359	47,729	10,834	67,744	126,307
Total Additions		9,557,705	387,660	595,490	54,016	1,037,166	783,931	1,560,649	145,494	2,490,074
Total Before Deductions		52,904,837	2,148,929	925,176	1,918,610	4,992,715	4,332,016	2,354,409	5,164,896	11,851,321

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Deductions										
Accumulated Deferred Income Tax	24	(8,925,996)	(361,616)	(68,682)	(384,102)	(814,400)	(728,484)	(165,359)	(1,033,969)	(1,927,812)
Accumulated Investment Tax Credit	24	(4,084)	(165)	(31)	(176)	(372)	(333)	(76)	(473)	(882)
Customer Advances For Construction	Direct	(727,256)	(1,349)		(1,120)	(2,469)	(2,717)		(181,580)	(184,297)
Total Deductions		(9,657,336)	(363,130)	(68,713)	(385,398)	(817,241)	(731,534)	(165,435)	(1,216,022)	(2,112,991)
Total Rate Base		43,247,501	1,785,799	856,463	1,533,212	4,175,474	3,600,482	2,188,974	3,948,874	9,738,330
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	45,522,909	0	0	0	0	0	0	0	0
Firm General	Direct	26,717,947	1,551,191	6,102,566	817,315	8,471,072	3,139,095	14,543,917	563,863	18,246,875
Small Interruptible	Direct	2,001,287	0	0	0	0	0	0	0	0
Large Interruptible	Direct	754,669	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		74,996,812	1,551,191	6,102,566	817,315	8,471,072	3,139,095	14,543,917	563,863	18,246,875
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	11	1,480	0	0	123	123	0	0	40	40
NSF Check Fees	11	28,024	0	0	2,327	2,327	0	0	765	765
Miscellaneous	24	15,830	641	122	681	1,444	1,292	293	1,834	3,419
Rent From Gas Property	24	244,710	9,914	1,883	10,530	22,327	19,972	4,533	28,347	52,852
Other Gas Revenues										
Miscellaneous	31	42,705	1,071	242	2,396	3,709	2,158	583	4,076	6,817
Transport and Penalty Revenue - Net	24	36,077	1,462	278	1,552	3,292	2,944	668	4,179	7,791
Total Other Operating Revenue		368,826	13,088	2,525	17,609	33,222	26,366	6,077	39,241	71,684
Unbilled Revenue	26	(1,254,664)	(33,030)	(91,132)	(17,398)	(141,560)	(66,842)	(232,094)	(12,130)	(311,066)
Total Operating Revenues		74,110,974	1,531,249	6,013,959	817,526	8,362,734	3,098,619	14,317,900	590,974	18,007,493
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	52,735,031	1,550,414	4,502,040	0	6,052,454	3,137,522	10,365,633	0	13,503,155
Production Expense										
Production Expense	3	188,558	0	20,833	0	20,833	0	50,158	0	50,158
Other Gas Supply Expenses	3	73,609	0	8,133	0	8,133	0	19,581	0	19,581
Total Production Expense		262,167	0	28,966	0	28,966	0	69,739	0	69,739

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet			Total Small Firm General	Firm General > 500 cubic feet			Total Large Firm General
			Demand	Energy	Customer		Demand	Energy	Customer	
Operation										
Load Dispatch	1	74,482	0	5,552	0	5,552	0	13,367	0	13,367
Mains and Services	22	1,138,365	78,169	0	34,574	112,743	157,534	0	94,057	251,591
Measuring Stations - General	18	34,815	4,099	0	0	4,099	8,262	0	0	8,262
Measuring Stations - Industrial	21	14,521	1,329	0	0	1,329	2,679	0	0	2,679
Measuring Stations - City Gate	19	0	0	0	0	0	0	0	0	0
Meters & House Regulators	16	267,551	0	0	19,816	19,816	0	0	52,931	52,931
Customer Installations	10	538,992	0	0	39,273	39,273	0	0	106,841	106,841
Other Gas Distribution	27	832,223	33,630	2,234	37,679	73,543	67,775	5,377	102,112	175,264
Rents	27	33,379	1,349	90	1,511	2,950	2,718	216	4,096	7,030
Supervision & Engineering	27	514,850	20,805	1,382	23,310	45,497	41,929	3,327	63,171	108,427
Total Operation Expense		3,449,178	139,381	9,258	156,163	304,802	280,897	22,287	423,208	726,392
Maintenance										
Structures & Improvements	17	1,179	120	0	0	120	242	0	0	242
Mains	13	138,093	16,260	0	0	16,260	32,769	0	0	32,769
Measuring Stations - General	18	28,158	3,316	0	0	3,316	6,682	0	0	6,682
Measuring Stations - Industrial	21	15,721	1,439	0	0	1,439	2,900	0	0	2,900
Measuring Stations - City Gate	19	0	0	0	0	0	0	0	0	0
Services	10	155,111	0	0	11,302	11,302	0	0	30,747	30,747
Meters & House Regulators	16	284,028	0	0	21,036	21,036	0	0	56,190	56,190
Other Equipment	28	120,738	4,101	0	6,274	10,375	8,264	0	16,868	25,132
Supervision & Engineering	28	130,671	4,438	0	6,790	11,228	8,944	0	18,255	27,199
Total Maintenance Expense		873,699	29,674	0	45,402	75,076	59,801	0	122,060	181,861
Total Distribution Expenses		4,322,877	169,055	9,258	201,565	379,878	340,698	22,287	545,268	908,253
Customer Accounts	8	96,853	0	0	8,036	8,036	0	0	2,643	2,643
Meter Reading	10	230,640	0	0	16,805	16,805	0	0	45,718	45,718
Customer Records & Collection	8	1,376,127	0	0	114,174	114,174	0	0	37,547	37,547
Uncollectible Accounts	11	173,361	0	0	14,392	14,392	0	0	4,733	4,733
Miscellaneous Customer Accounts	8	71,102	0	0	5,899	5,899	0	0	1,940	1,940
Customer Service & Information	8	89,100	0	0	7,392	7,392	0	0	2,431	2,431
Sales Expenses	8	119,573	0	0	9,921	9,921	0	0	3,262	3,262
Administration & General Expenses	30	4,127,510	103,500	23,402	231,534	358,436	208,584	56,341	393,994	658,919
Total Gas O&M Expenses		63,604,341	1,822,969	4,563,666	609,718	6,996,353	3,686,804	10,514,000	1,037,536	15,238,340
O&M Excl. Cost of Gas and A&G		6,741,800	169,055	38,224	378,184	585,463	340,698	92,026	643,542	1,076,266

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
O&M Excl. Cost of Gas		10,869,310	272,555	61,626	609,718	943,899	549,282	148,367	1,037,536	1,735,185
Depreciation Expense										
Production Plant	3	101,594	0	11,225	0	11,225	0	27,025	0	27,025
Distribution Plant										
Rights of Way	13	317	37	0	0	37	75	0	0	75
Structures & Improvements	17	3,533	359	0	0	359	724	0	0	724
Mains	13	590,840	69,571	0	0	69,571	140,206	0	0	140,206
Meas. & Reg. Equip. - General	18	18,947	2,231	0	0	2,231	4,496	0	0	4,496
Meas. & Reg. Equip. - City Gate	19	3,603	184	0	0	184	149	0	0	149
Services	10	1,160,453	0	0	84,554	84,554	0	0	230,029	230,029
Meters	10	519,807	0	0	37,875	37,875	0	0	103,038	103,038
Service Regulators	20	30,901	0	0	2,622	2,622	0	0	6,005	6,005
Ind. Meas. & Reg. Station Equipment	21	4,563	418	0	0	418	842	0	0	842
Property on Customer Premise	13	0	0	0	0	0	0	0	0	0
Cathodic Protection & Other Equipment	13	34,801	4,098	0	0	4,098	8,258	0	0	8,258
Total Distribution Plant		2,469,359	76,898	11,225	125,051	213,174	154,750	27,025	339,072	520,847
General Plant	15	115,122	5,851	0	4,790	10,641	11,780	0	12,912	24,692
Amort. of Intangible Plant - General	15	0	0	0	0	0	0	0	0	0
Common Plant	15	315,830	16,053	0	13,140	29,193	32,317	0	35,423	67,740
Amort. of Intangible Plant - Common	15	110,987	5,641	0	4,618	10,259	11,357	0	12,448	23,805
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Total Depreciation Expense		3,011,298	104,443	11,225	147,599	263,267	210,204	27,025	399,855	637,084
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	64,378	0	7,113	0	7,113	0	17,125	0	17,125
Ad Valorem Taxes-Other	15	2,439,698	124,005	0	101,503	225,508	249,637	0	273,631	523,268
Other Taxes - Payroll, Franchise, Other	31	448,033	11,235	2,540	25,133	38,908	22,641	6,116	42,767	71,524
Other Taxes - Revenue	26	355,910	9,370	25,851	4,935	40,156	18,961	65,838	3,441	88,240
Total Taxes Other Than Income Taxes		3,308,019	144,610	35,504	131,571	311,685	291,239	89,079	319,839	700,157
Total Operating Expense		69,923,658	2,072,022	4,610,395	888,888	7,571,305	4,188,247	10,630,104	1,757,230	16,575,581
Interest Expense	24	1,269,714	51,439	9,770	54,638	115,847	103,626	23,522	147,081	274,229
Taxable Income Before Adjustments		2,917,602	(592,212)	1,393,794	(126,000)	675,582	(1,193,254)	3,664,274	(1,313,337)	1,157,683

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Firm General > 500 cubic feet Energy	Firm General > 500 cubic feet Customer	Total Large Firm General
Deductions										
Unrecovered Purchased Gas Cost	33	52,394	2,091	3,730	0	5,821	4,231	9,783	0	14,014
Other Income Tax Charges	24	6,128,908	248,298	47,159	263,738	559,195	500,203	113,542	709,960	1,323,705
Preferred Dividend Paid Deduction	24	13,836	561	106	595	1,262	1,129	256	1,603	2,988
Total Deductions		6,195,138	250,950	50,995	264,333	566,278	505,563	123,581	711,563	1,340,707
Taxable Income (Before State Income Tax)		(3,277,536)	(843,162)	1,342,799	(390,333)	109,304	(1,698,817)	3,540,693	(2,024,900)	(183,024)
Less: State Income Tax	35	(386,615)	(99,459)	158,395	(46,043)	12,893	(200,391)	417,657	(238,855)	(21,589)
Federal Taxable Income		(2,890,921)	(743,703)	1,184,404	(344,290)	96,411	(1,498,426)	3,123,036	(1,786,045)	(161,435)
Federal Income Tax										
@ Current Rate of 35%	35.00%	(1,011,822)	(260,296)	414,541	(120,502)	33,743	(524,449)	1,093,063	(625,116)	(56,502)
State Income Taxes	35	(386,615)	(99,459)	158,395	(46,043)	12,893	(200,391)	417,657	(238,855)	(21,589)
Credits and Adjustments	40	29,134	1,180	240	1,243	2,663	2,378	581	3,346	6,305
Rounding & Prior Year's Adjustments - Federal	24	(1,236,864)	(50,109)	(9,517)	(53,225)	(112,851)	(100,945)	(22,914)	(143,276)	(267,135)
Federal and State Income Taxes		(2,606,167)	(408,684)	563,659	(218,527)	(63,552)	(823,407)	1,488,387	(1,003,901)	(338,921)
Rounding & Prior Year's Adjustment - State	24	(324,018)	(13,127)	(2,493)	(13,943)	(29,563)	(26,444)	(6,003)	(37,534)	(69,981)
Federal & State Income Taxes		(2,930,185)	(421,811)	561,166	(232,470)	(93,115)	(849,851)	1,482,384	(1,041,435)	(408,902)
Deferred Income Taxes										
Unrecovered Purchased Gas Cost	33	(20,643)	(824)	(1,470)	0	(2,294)	(1,667)	(3,855)	0	(5,522)
Other Deferred Income Tax Chgs	24	2,206,874	89,406	16,981	94,966	201,353	180,111	40,884	255,640	476,635
Closing/Filing & Out of Period	24	1,302,970	52,787	10,026	56,069	118,882	106,340	24,138	150,933	281,411
Total Deferred Income Taxes		3,489,201	141,369	25,537	151,035	317,941	284,784	61,167	406,573	752,524
Total Operating Expenses		70,482,674	1,791,580	5,197,098	807,453	7,796,131	3,623,180	12,173,655	1,122,368	16,919,203
Total Operating Income		3,628,300	(260,331)	816,861	10,073	566,603	(524,561)	2,144,245	(531,394)	1,088,290

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Summary of Pro Forma Rate Base Adjustments										
Plant										
Plant Additions - Adj. A										
Production	3	74,440	0	8,225	0	8,225	0	19,802	0	19,802
Distribution										
Mains-Demand Related	5	957,339	112,726	0	0	112,726	227,175	0	0	227,175
Meas. & Reg. Equip. General	13	14,164	1,668	0	0	1,668	3,361	0	0	3,361
Services	10	1,324,687	0	0	96,521	96,521	0	0	262,584	262,584
Positive Meters	10	573,629	0	0	41,796	41,796	0	0	113,707	113,707
Service Regulators	10	131,754	0	0	9,600	9,600	0	0	26,117	26,117
Cathodic Protection Equip	13	109,023	12,837	0	0	12,837	25,871	0	0	25,871
Other Distribution Equipment	13	(118)	(14)	0	0	(14)	(28)	0	0	(28)
Total Distribution Plant Additions		3,110,478	127,217	0	147,917	275,134	256,379	0	402,408	658,787
General	15	309,554	15,734	0	12,879	28,613	31,675	0	34,719	66,394
Common	15	394,348	20,044	0	16,407	36,451	40,351	0	44,229	84,580
Common Intangible	8	2,468,802	0	0	204,831	204,831	0	0	67,359	67,359
Total Plant Additions - Adj. A		6,357,622	162,995	8,225	382,034	553,254	328,405	19,802	548,715	896,922
Accumulated Reserve for Depreciation										
Plant Additions - Adj. B										
Production	3	102,565	0	11,332	0	11,332	0	27,283	0	27,283
Distribution	23	2,607,909	131,477	0	109,147	240,624	264,691	0	294,364	559,055
General	15	(33,342)	(1,695)	0	(1,387)	(3,082)	(3,412)	0	(3,740)	(7,152)
Common	15	360,927	18,345	0	15,016	33,361	36,931	0	40,481	77,412
Common Intangible	8	164,587	0	0	13,655	13,655	0	0	4,491	4,491
Total Accumulated Reserve - Adj. B		3,202,646	148,127	11,332	136,431	295,890	298,210	27,283	335,596	661,089
Net Adjustment to Plant		3,154,976	14,868	(3,107)	245,603	257,364	30,195	(7,481)	213,119	235,833
Additions										
Materials and Supplies - Adj. C	15	99,695	5,067	0	4,148	9,215	10,201	0	11,182	21,383
Gas in Underground Storage - Adj. D	33	(855,502)	(34,137)	(60,904)	0	(95,041)	(69,082)	(159,741)	0	(228,823)
Prepaid Insurance - Adj. E	24	93,808	3,800	722	4,037	8,559	7,656	1,738	10,867	20,261
Prepaid Demand and Commodity-Adj. F	33	(642,915)	(25,654)	(45,770)	0	(71,424)	(51,916)	(120,047)	0	(171,963)
Unamortized Loss on Debt - Adj. G	24	(53,806)	(2,180)	(414)	(2,315)	(4,909)	(4,391)	(997)	(6,233)	(11,621)
Provision for Pensions & Benefits - Adj. H	24	1,268,837	51,404	9,763	54,600	115,767	103,555	23,506	146,980	274,041

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Provision for Injuries & Damages - Adj. I	24	(109,736)	(4,446)	(844)	(4,722)	(10,012)	(8,956)	(2,033)	(12,712)	(23,701)
Deferred FAS 106 Costs - Adj. J	24	273,775	11,091	2,107	11,781	24,979	22,344	5,072	31,714	59,130
Total		74,156	4,945	(95,340)	67,529	(22,866)	9,411	(252,502)	181,798	(61,293)
Deductions										
Accumulated Def. Inc. Tax										
Plant Additions - Adj. K	41	1,887,637	90,037	6,455	78,371	174,863	181,262	15,540	202,230	399,032
Normalization - Adj L	24	(25,349)	(1,027)	(195)	(1,091)	(2,313)	(2,069)	(470)	(2,936)	(5,475)
Def. FAS 106 - Adj. J	24	105,855	4,288	815	4,555	9,658	8,639	1,961	12,262	22,862
Unamortized Loss on Debt - Adj. G	24	(31,526)	(1,277)	(243)	(1,357)	(2,877)	(2,573)	(584)	(3,652)	(6,809)
Pension - Adj. H	24	846,179	34,281	6,511	36,413	77,205	69,060	15,676	98,020	182,756
Injuries and Damages - Adj. I	24	(41,583)	(1,685)	(320)	(1,789)	(3,794)	(3,394)	(770)	(4,817)	(8,981)
Investment Tax Credits - Adj. M	24	(3,488)	(141)	(27)	(150)	(318)	(285)	(65)	(404)	(754)
Customer Advances for Construction - Adj. N	Direct	(20,926)	(1,055)		(876)	(1,931)	(2,124)		(2,362)	(4,486)
Total		2,716,799	123,421	12,996	114,076	250,493	248,516	31,288	298,341	578,145
Total Pro Forma Adjustments - Rate Base		512,333	(103,608)	(111,443)	199,056	(15,995)	(208,910)	(291,271)	96,576	(403,605)
Pro Forma Adjustments - Operating Income										
Pro Forma Revenue Adjustments										
Revenue Adjustments - Adj. No. 1-3 to Proforma										
Residential	Direct	(9,792,993)				0				0
Firm General	Direct	(5,461,164)	0	(1,822,709)	(249)	(1,822,958)	0	(3,644,027)	5,821	(3,638,206)
Small Interruptible	Direct	(613,776)				0				0
Large Interruptible	Direct	(205,865)				0				0
Total Retail Sales Adjustment		(16,073,798)	0	(1,822,709)	(249)	(1,822,958)	0	(3,644,027)	5,821	(3,638,206)
Unbilled Revenue	26	1,254,664	33,030	91,132	17,398	141,560	66,842	232,094	12,130	311,066
Total		(14,819,134)	33,030	(1,731,577)	17,149	(1,681,398)	66,842	(3,411,933)	17,951	(3,327,140)
Other Revenue - Adj. No. 4	23	47,286	2,384	0	1,979	4,363	4,799	0	5,337	10,136
Total Pro Forma Revenue Adjustments		(14,771,848)	35,414	(1,731,577)	19,128	(1,677,035)	71,641	(3,411,933)	23,288	(3,317,004)

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
OPERATION & MAINTENANCE EXPENSES										
Cost of Gas - Adj. No. 5	Direct	(13,880,459)	0	(1,735,946)		(1,735,946)	0	(3,110,617)		(3,110,617)
Labor Expense - Adj. No. 6										
Other Gas Supply	30	2,495	63	14	140	217	126	34	238	398
Production	3	1,334	0	147	0	147	0	355	0	355
Distribution	29	160,710	6,285	344	7,494	14,123	12,666	829	20,271	33,766
Customer Accounting	8	50,020	0	0	4,150	4,150	0	0	1,365	1,365
Customer Service	8	2,645	0	0	219	219	0	0	72	72
Sales	8	4,111	0	0	341	341	0	0	112	112
A&G	30	48,407	1,214	274	2,715	4,203	2,446	661	4,621	7,728
Total -Labor Expense - Adj. No. 6		269,722	7,562	779	15,059	23,400	15,238	1,879	26,679	43,796
Benefits Expense - Adj. No. 7	30	(75,501)	(1,893)	(428)	(4,235)	(6,556)	(3,815)	(1,031)	(7,207)	(12,053)
Vehicles and Work Equip. - Adj. No. 8	30	(6,716)	(168)	(38)	(377)	(583)	(339)	(92)	(641)	(1,072)
Company Consumption - Adj. No. 9	30	(8,120)	(204)	(46)	(455)	(705)	(410)	(111)	(775)	(1,296)
Uncollectible Accounts - Adj. No. 10	11	(14,963)	0	0	(1,242)	(1,242)	0	0	(409)	(409)
Advertising - Adj. No. 11	8	(31,656)	0	0	(2,626)	(2,626)	0	0	(864)	(864)
Insurance Expense - Adj. No. 12	30	13,839	347	78	776	1,201	699	189	1,321	2,209
Industry Dues - Adj. No. 13	30	(7,138)	(179)	(40)	(400)	(619)	(361)	(97)	(681)	(1,139)
Regulatory Commission Expense - Adj. No. 14	30	108,300	2,716	614	6,075	9,405	5,473	1,478	10,338	17,289
Total		53,546	2,512	568	1,751	4,831	5,062	1,367	8,289	14,718
Total Adjustments to O&M		(13,632,692)	8,181	(1,735,027)	12,575	(1,714,271)	16,485	(3,108,402)	27,761	(3,064,156)
DEPRECIATION EXPENSE										
Average Annual Depreciation - Adj. No. 15										
Production Plant	3	1,943	0	215	0	215	0	517	0	517
Distribution Plant	23	1,082,553	54,577	0	45,307	99,884	109,874	0	122,192	232,066
General Plant	41	(4,128)	(197)	(14)	(171)	(382)	(396)	(34)	(442)	(872)
Common	8	331,936	0	0	27,540	27,540	0	0	9,057	9,057
Total Average Annual Depreciation Adj. 15		1,412,304	54,380	201	72,676	127,257	109,478	483	130,807	240,768

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	Allocation Factor	Total Montana	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
TAXES OTHER THAN INCOME										
Ad Valorem Taxes - Adj. No. 16										
Production Plant	3	1,578	0	174	0	174	0	420	0	420
Distribution Plant	23	101,664	5,125	0	4,255	9,380	10,318	0	11,475	21,793
General Plant	41	5,288	252	18	220	490	508	44	567	1,119
Common Plant	41	5,857	279	20	243	542	562	48	627	1,237
Total Ad Valorem Taxes		114,387	5,656	212	4,718	10,586	11,388	512	12,669	24,569
Payroll Taxes - Adj. No. 17	31	20,322	510	115	1,140	1,765	1,027	277	1,940	3,244
Montana Consumer Counsel & PSC Tax - Adj. 18	26	(167,229)	(4,402)	(12,147)	(2,319)	(18,868)	(8,909)	(30,935)	(1,617)	(41,461)
Total Adjustments to Taxes Other than Income		(32,520)	1,764	(11,820)	3,539	(6,517)	3,506	(30,146)	12,992	(13,648)
CURRENT INCOME TAXES										
Interest Annualization - Adj. No. 19	24	(51,878)	(2,102)	(399)	(2,232)	(4,733)	(4,234)	(961)	(6,009)	(11,204)
Tax Depreciation on Plant Additions - Adj. No. 20	41	2,817,177	134,375	9,633	116,963	260,971	270,521	23,193	301,815	595,529
Other Tax Deductions - Adj. No. 21	24	(400,022)	(16,206)	(3,078)	(17,214)	(36,498)	(32,647)	(7,411)	(46,338)	(86,396)
		2,365,277	116,067	6,156	97,517	219,740	233,640	14,821	249,468	497,929
Net Adjustments to Operating Income		(4,884,217)	(144,978)	8,913	(167,179)	(303,244)	(291,468)	(288,689)	(397,740)	(977,897)
Income Taxes on Pro Forma Adj. - Adj. No. 22	(Calculated)	(1,923,771)	(57,103)	3,511	(65,848)	(119,440)	(114,802)	(113,707)	(156,660)	(385,169)
0.393875										
Elimination of Closing/Filing&Res. - Adj. No. 23	24	1,560,882	63,235	12,010	67,168	142,413	127,389	28,916	180,809	337,114
Total Adjustments to Current Income Taxes		(362,889)	6,132	15,521	1,320	22,973	12,587	(84,791)	24,149	(48,055)
DEFERRED INCOME TAXES										
Plant Additions - Adj. No. 20	41	1,109,616	52,927	3,794	46,069	102,790	106,552	9,135	118,878	234,565
Elimination of Closing/Filing - Adj. No. 23	24	(1,302,970)	(52,787)	(10,026)	(56,069)	(118,882)	(106,340)	(24,138)	(150,933)	(281,411)
Other Tax Deductions	24	38,579	1,563	297	1,660	3,520	3,149	715	4,469	8,333
Total Adjustments to Deferred Income Taxes		(154,775)	1,703	(5,935)	(8,340)	(12,572)	3,361	(14,288)	(27,586)	(38,513)
Total Adjustments:		(2,001,276)	(36,746)	5,483	(62,642)	(93,905)	(73,776)	(174,789)	(144,835)	(393,400)

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Rate Base										
Gas Plant in Service										
Production Plant	3	3,034,769	0	65,485	0	65,485	0	0	0	0
Distribution Plant										
Land	13	15,962	375	0	0	375	917	0	0	917
Rights of Way	13	22,846	536	0	0	536	1,313	0	0	1,313
Structures & Improvements	13	168,491	3,955	0	0	3,955	9,683	0	0	9,683
Direct to Small IT	Direct	24,611	24,611	0	0	24,611	0	0	0	0
Direct to Large IT	Direct	2,062	0	0	0	0	2,062	0	0	2,062
Mains - $28,623,324										
Demand Related 100%	5	28,623,324	671,864	0	0	671,864	1,645,011	0	0	1,645,011
Meas. & Reg. Equip. - General	13	576,181	13,524	0	0	13,524	33,114	0	0	33,114
Meas. & Reg. Equip. - City Gate	13	22,301	523	0	0	523	1,282	0	0	1,282
Direct to Firm General	Direct	3,913	0	0	0	0	0	0	0	0
Direct to Small IT	Direct	83,476	83,476	0	0	83,476	0	0	0	0
Direct to Large IT	Direct	18,532	0	0	0	0	18,532	0	0	18,532
Services	10	20,458,685	0	0	334,068	334,068	0	0	56,506	56,506
Meters	10	18,117,820	0	0	295,845	295,845	0	0	50,041	50,041
Service Regulators	10	1,979,814	0	0	32,328	32,328	0	0	5,468	5,468
Direct to Firm General	Direct	27,085	0	0	0	0	0	0	0	0
Direct to Small IT	Direct	12,521	0	0	12,521	12,521	0	0	0	0
Ind. Meas. & Reg. Station Equipment	13	146,005	3,427	0	0	3,427	8,391	0	0	8,391
Direct to Small IT	Direct	8,161	8,161	0	0	8,161	0	0	0	0
Direct to Large IT	Direct	33,659	0	0	0	0	33,659	0	0	33,659
Property on Customer Premise	13	148,674	3,490	0	0	3,490	8,544	0	0	8,544
Cathodic Protection & Other Equipment	13	1,183,575	27,782	0	0	27,782	68,021	0	0	68,021
Distribution Plant		71,677,698	841,724	0	674,762	1,516,486	1,830,529	0	112,015	1,942,544
General Plant	15	5,982,213	70,250	0	56,316	126,566	152,776	0	9,349	162,125
Intangible Plant - General	15	55,760	655	0	525	1,180	1,424	0	87	1,511
Common Plant	15	10,595,932	124,430	0	99,748	224,178	270,602	0	16,559	287,161
Intangible Plant - Common	15	2,759,471	32,405	0	25,977	58,382	70,472	0	4,312	74,784
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Total Gas Plant in Service		94,105,843	1,069,464	65,485	857,328	1,992,277	2,325,803	0	142,322	2,468,125

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Less: Accumulated Depreciation										
Production Plant	3	50,797	0	1,096	0	1,096	0	0	0	0
Distribution Plant										
Rights of Way	13	14,219	334	0	0	334	817	0	0	817
Structures & Improvements	17	164,245	24,040	0	0	24,040	9,884	0	0	9,884
Mains	13	19,340,970	453,983	0	0	453,983	1,111,545	0	0	1,111,545
Meas. & Reg. Equip. - General	18	457,800	10,745	0	0	10,745	26,310	0	0	26,310
Meas. & Reg. Equip. - City Gate	19	126,357	82,777	0	0	82,777	19,526	0	0	19,526
Services	10	15,458,953	0	0	252,428	252,428	0	0	42,697	42,697
Meters	10	5,457,201	0	0	89,110	89,110	0	0	15,073	15,073
Service Regulators	20	887,096	0	0	19,701	19,701	0	0	2,402	2,402
Ind. Meas. & Reg. Station Equipment	21	67,888	4,188	0	0	4,188	15,199	0	0	15,199
Property on Customer Premise	13	143,163	3,360	0	0	3,360	8,228	0	0	8,228
Cathodic Protection & Other Equipment	13	775,459	18,202	0	0	18,202	44,566	0	0	44,566
Distribution Plant		42,893,351	597,629	0	361,239	958,868	1,236,075	0	60,172	1,296,247
General Plant	15	3,177,682	37,316	0	29,914	67,230	81,153	0	4,966	86,119
Intangible Plant - General	15	55,760	655	0	525	1,180	1,424	0	87	1,511
Common Plant	15	2,977,057	34,960	0	28,026	62,986	76,029	0	4,652	80,681
Intangible Plant - Common	15	2,104,538	24,714	0	19,812	44,526	53,746	0	3,289	57,035
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		51,259,185	695,274	1,096	439,516	1,135,886	1,448,427	0	73,166	1,521,593
Net Gas Plant in Service		42,846,658	374,190	64,389	417,812	856,391	877,376	0	69,156	946,532
CWIP in Service	15	500,474	5,877	0	4,711	10,588	12,781	0	782	13,563
Total Gas Plant in Service		43,347,132	380,067	64,389	422,523	866,979	890,157	0	69,938	960,095
Additions										
Materials & Supplies	15	533,337	6,263	0	5,021	11,284	13,621	0	833	14,454
Prepaid Insurance	24	25,908	226	39	253	518	531	0	42	573
Gas in Underground Storage	33	7,134,766	16,888	98,619	0	115,507	0	0	0	0
Prepaid Demand/Commodity	33	1,149,982	2,722	15,895	0	18,617	0	0	0	0
Other	24	128,892	1,126	194	1,257	2,577	2,639	0	208	2,847
Unamortized Loss on Debt	24	584,820	5,107	879	5,703	11,689	11,975	0	944	12,919
Total Additions		9,557,705	32,332	115,626	12,234	160,192	28,766	0	2,027	30,793
Total Before Deductions		52,904,837	412,399	180,015	434,757	1,027,171	918,923	0	71,965	990,888

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Deductions										
Accumulated Deferred Income Tax	24	(8,925,996)	(77,953)	(13,414)	(87,040)	(178,407)	(182,779)	0	(14,407)	(197,186)
Accumulated Investment Tax Credit	24	(4,084)	(36)	(6)	(40)	(82)	(84)	0	(7)	(91)
Customer Advances For Construction	Direct	(727,256)	(988)		(137,889)	(138,877)				0
Total Deductions		(9,657,336)	(78,977)	(13,420)	(224,969)	(317,366)	(182,863)	0	(14,414)	(197,277)
Total Rate Base		43,247,501	333,422	166,595	209,788	709,805	736,060	0	57,551	793,611
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	45,522,909	0	0	0	0	0	0	0	0
Firm General	Direct	26,717,947	0	0	0	0	0	0	0	0
Small Interruptible	Direct	2,001,287	85,870	1,828,417	87,000	2,001,287	0	0	0	0
Large Interruptible	Direct	754,669	0	0	0	0	0	711,349	43,320	754,669
Total Sales & Transportation Revenues		74,996,812	85,870	1,828,417	87,000	2,001,287	0	711,349	43,320	754,669
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	11	1,480	0	0	0	0	0	0	0	0
NSF Check Fees	11	28,024	0	0	0	0	0	0	0	0
Miscellaneous	24	15,830	138	24	154	316	324	0	26	350
Rent From Gas Property	24	244,710	2,137	368	2,386	4,891	5,011	0	395	5,406
Other Gas Revenues										
Miscellaneous	31	42,705	228	83	318	629	575	220	53	848
Transport and Penalty Revenue - Net	24	36,077	315	54	352	721	739	0	58	797
Total Other Operating Revenue		368,826	2,818	529	3,210	6,557	6,649	220	532	7,401
Unbilled Revenue	26	(1,254,664)	(1,828)	(25,864)	(1,853)	(29,545)	0	(11,009)	(677)	(11,686)
Total Operating Revenues		74,110,974	86,860	1,803,082	88,357	1,978,299	6,649	700,560	43,175	750,384
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	52,735,031	91,968	1,085,155	0	1,177,123	0	92,009	0	92,009
Production Expense										
Production Expense	3	188,558	0	4,069	0	4,069	0	0	0	0
Other Gas Supply Expenses	3	73,609	0	1,588	0	1,588	0	0	0	0
Total Production Expense		262,167	0	5,657	0	5,657	0	0	0	0

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Distribution Expenses										
Operation										
Load Dispatch	1	74,482	0	4,489	0	4,489	0	20,825	0	20,825
Mains and Services	22	1,138,365	15,583	0	7,748	23,331	38,153	0	1,311	39,464
Measuring Stations - General	18	34,815	817	0	0	817	2,001	0	0	2,001
Measuring Stations - Industrial	21	14,521	896	0	0	896	3,251	0	0	3,251
Measuring Stations - City Gate	19	0	0	0	0	0	0	0	0	0
Meters & House Regulators	16	267,551	0	0	4,527	4,527	0	0	738	738
Customer Installations	10	538,992	0	0	8,801	8,801	0	0	1,489	1,489
Other Gas Distribution	27	832,223	6,958	1,806	8,479	17,243	17,461	8,378	1,423	27,262
Rents	27	33,379	279	72	340	691	700	336	57	1,093
Supervision & Engineering	27	514,850	4,305	1,117	5,245	10,667	10,802	5,183	881	16,866
Total Operation Expense		3,449,178	28,838	7,484	35,140	71,462	72,368	34,722	5,899	112,989
Maintenance										
Structures & Improvements	17	1,179	173	0	0	173	71	0	0	71
Mains	13	138,093	3,241	0	0	3,241	7,936	0	0	7,936
Measuring Stations - General	18	28,158	661	0	0	661	1,618	0	0	1,618
Measuring Stations - Industrial	21	15,721	970	0	0	970	3,520	0	0	3,520
Measuring Stations - City Gate	19	0	0	0	0	0	0	0	0	0
Services	10	155,111	0	0	2,533	2,533	0	0	428	428
Meters & House Regulators	16	284,028	0	0	4,805	4,805	0	0	783	783
Other Equipment	28	120,738	979	0	1,424	2,403	2,550	0	235	2,785
Supervision & Engineering	28	130,671	1,059	0	1,541	2,600	2,760	0	254	3,014
Total Maintenance Expense		873,699	7,083	0	10,303	17,386	18,455	0	1,700	20,155
Total Distribution Expenses		4,322,877	35,921	7,484	45,443	88,848	90,823	34,722	7,599	133,144
Customer Accounts	8	96,853	0	0	54	54	0	0	6	6
Meter Reading	10	230,640	0	0	3,766	3,766	0	0	637	637
Customer Records & Collection	8	1,376,127	0	0	767	767	0	0	87	87
Uncollectible Accounts	11	173,361	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	8	71,102	0	0	40	40	0	0	5	5
Customer Service & Information	8	89,100	0	0	50	50	0	0	6	6
Sales Expenses	8	119,573	0	0	67	67	0	0	8	8
Administration & General Expenses	30	4,127,510	21,992	8,045	30,726	60,763	55,604	21,258	5,111	81,973
Total Gas O&M Expenses		63,604,341	149,881	1,106,341	80,913	1,337,135	146,427	147,989	13,459	307,875
O&M Excl. Cost of Gas and A&G		6,741,800	35,921	13,141	50,187	99,249	90,823	34,722	8,348	133,893

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
O&M Excl. Cost of Gas		10,869,310	57,913	21,186	80,913	160,012	146,427	55,980	13,459	215,866
Depreciation Expense										
Production Plant	3	101,594	0	2,192	0	2,192	0	0	0	0
Distribution Plant										
Rights of Way	13	317	7	0	0	7	18	0	0	18
Structures & Improvements	17	3,533	517	0	0	517	213	0	0	213
Mains	13	590,840	13,869	0	0	13,869	33,956	0	0	33,956
Meas. & Reg. Equip. - General	18	18,947	445	0	0	445	1,089	0	0	1,089
Meas. & Reg. Equip. - City Gate	19	3,603	2,360	0	0	2,360	557	0	0	557
Services	10	1,160,453	0	0	18,949	18,949	0	0	3,205	3,205
Meters	10	519,807	0	0	8,488	8,488	0	0	1,436	1,436
Service Regulators	20	30,901	0	0	686	686	0	0	84	84
Ind. Meas. & Reg. Station Equipment	21	4,563	282	0	0	282	1,022	0	0	1,022
Property on Customer Premise	13	0	0	0	0	0	0	0	0	0
Cathodic Protection & Other Equipment	13	34,801	817	0	0	817	2,000	0	0	2,000
Total Distribution Plant		2,469,359	18,297	2,192	28,123	48,612	38,855	0	4,725	43,580
General Plant	15	115,122	1,352	0	1,084	2,436	2,940	0	180	3,120
Amort. of Intangible Plant - General	15	0	0	0	0	0	0	0	0	0
Common Plant	15	315,830	3,709	0	2,973	6,682	8,066	0	494	8,560
Amort. of Intangible Plant - Common	15	110,987	1,303	0	1,045	2,348	2,834	0	173	3,007
Gas Plant Leased to Others	15	0	0	0	0	0	0	0	0	0
Total Depreciation Expense		3,011,298	24,661	2,192	33,225	60,078	52,695	0	5,572	58,267
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	64,378	0	1,389	0	1,389	0	0	0	0
Ad Valorem Taxes-Other	15	2,439,698	28,650	0	22,967	51,617	62,306	0	3,813	66,119
Other Taxes - Payroll, Franchise, Other	31	448,033	2,387	873	3,335	6,595	6,036	2,307	555	8,898
Other Taxes - Revenue	26	355,910	519	7,337	526	8,382	0	3,123	192	3,315
Total Taxes Other Than Income Taxes		3,308,019	31,556	9,599	26,828	67,983	68,342	5,430	4,560	78,332
Total Operating Expense		69,923,658	206,098	1,118,132	140,966	1,465,196	267,464	153,419	23,591	444,474
Interest Expense	24	1,269,714	11,089	1,908	12,381	25,378	26,000	0	2,049	28,049
Taxable Income Before Adjustments		2,917,602	(130,327)	683,042	(64,990)	487,725	(286,815)	547,141	17,535	277,861

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Deductions										
Unrecovered Purchased Gas Cost	33	52,394	124	724	0	848	0	0	0	0
Other Income Tax Charges	24	6,128,908	53,525	9,210	59,765	122,500	125,502	0	9,892	135,394
Preferred Dividend Paid Deduction	24	13,836	121	21	135	277	283	0	22	305
Total Deductions		6,195,138	53,770	9,955	59,900	123,625	125,785	0	9,914	135,699
Taxable Income (Before State Income Tax)		(3,277,536)	(184,097)	673,087	(124,890)	364,100	(412,600)	547,141	7,621	142,162
Less: State Income Tax	35	(386,615)	(21,716)	79,397	(14,732)	42,949	(48,670)	64,540	899	16,769
Federal Taxable Income		(2,890,921)	(162,381)	593,690	(110,158)	321,151	(363,930)	482,601	6,722	125,393
Federal Income Tax										
@ Current Rate of 35%	35.00%	(1,011,822)	(56,833)	207,792	(38,555)	112,404	(127,376)	168,910	2,353	43,887
State Income Taxes	35	(386,615)	(21,716)	79,397	(14,732)	42,949	(48,670)	64,540	899	16,769
Credits and Adjustments	40	29,134	253	47	282	582	592	0	47	639
Rounding & Prior Year's Adjustments - Federal	24	(1,236,864)	(10,802)	(1,859)	(12,061)	(24,722)	(25,327)	0	(1,996)	(27,323)
Federal and State Income Taxes		(2,606,167)	(89,098)	285,377	(65,066)	131,213	(200,781)	233,450	1,303	33,972
Rounding & Prior Year's Adjustment - State	24	(324,018)	(2,830)	(487)	(3,160)	(6,477)	(6,635)	0	(523)	(7,158)
Federal & State Income Taxes		(2,930,185)	(91,928)	284,890	(68,226)	124,736	(207,416)	233,450	780	26,814
Deferred Income Taxes										
Unrecovered Purchased Gas Cost	33	(20,643)	(49)	(285)	0	(334)	0	0	0	0
Other Deferred Income Tax Chgs	24	2,206,874	19,273	3,316	21,520	44,109	45,190	0	3,562	48,752
Closing/Filing & Out of Period	24	1,302,970	11,379	1,958	12,706	26,043	26,681	0	2,103	28,784
Total Deferred Income Taxes		3,489,201	30,603	4,989	34,226	69,818	71,871	0	5,665	77,536
Total Operating Expenses		70,482,674	144,773	1,408,011	106,966	1,659,750	131,919	386,869	30,036	548,824
Total Operating Income		3,628,300	(57,913)	395,071	(18,609)	318,549	(125,270)	313,691	13,139	201,560

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Summary of Pro Forma Rate Base Adjustments										
Plant										
Plant Additions - Adj. A										
Production	3	74,440	0	1,606	0	1,606	0	0	0	0
Distribution										
Mains-Demand Related	5	957,339	22,471	0	0	22,471	55,019	0	0	55,019
Meas. & Reg. Equip. General	13	14,164	332	0	0	332	814	0	0	814
Services	10	1,324,687	0	0	21,631	21,631	0	0	3,659	3,659
Positive Meters	10	573,629	0	0	9,367	9,367	0	0	1,584	1,584
Service Regulators	10	131,754	0	0	2,151	2,151	0	0	364	364
Cathodic Protection Equip	13	109,023	2,559	0	0	2,559	6,266	0	0	6,266
Other Distribution Equipment	13	(118)	(3)	0	0	(3)	(7)	0	0	(7)
Total Distribution Plant Additions		3,110,478	25,359	0	33,149	58,508	62,092	0	5,607	67,699
General	15	309,554	3,635	0	2,914	6,549	7,905	0	484	8,389
Common	15	394,348	4,631	0	3,712	8,343	10,071	0	616	10,687
Common Intangible	8	2,468,802	0	0	1,377	1,377	0	0	156	156
Total Plant Additions - Adj. A		6,357,622	33,625	1,606	41,152	76,383	80,068	0	6,863	86,931
Accumulated Reserve for Depreciation										
Plant Additions - Adj. B										
Production	3	102,565	0	2,213	0	2,213	0	0	0	0
Distribution	23	2,607,909	30,236	0	24,685	54,921	65,997	0	4,102	70,099
General	15	(33,342)	(392)	0	(314)	(706)	(851)	0	(52)	(903)
Common	15	360,927	4,238	0	3,398	7,636	9,217	0	564	9,781
Common Intangible	8	164,587	0	0	92	92	0	0	10	10
Total Accumulated Reserve - Adj. B		3,202,646	34,082	2,213	27,861	64,156	74,363	0	4,624	78,987
Net Adjustment to Plant		3,154,976	(457)	(607)	13,291	12,227	5,705	0	2,239	7,944
Additions										
Materials and Supplies - Adj. C	15	99,695	1,171	0	939	2,110	2,546	0	156	2,702
Gas in Underground Storage - Adj. D	33	(855,502)	(2,025)	(11,825)	0	(13,850)	0	0	0	0
Prepaid Insurance - Adj. E	24	93,808	819	141	915	1,875	1,921	0	151	2,072
Prepaid Demand and Commodity-Adj. F	33	(642,915)	(1,522)	(8,887)	0	(10,409)	0	0	0	0
Unamortized Loss on Debt - Adj. G	24	(53,806)	(470)	(81)	(525)	(1,076)	(1,102)	0	(87)	(1,189)
Provision for Pensions & Benefits - Adj. H	24	1,268,837	11,081	1,907	12,373	25,361	25,982	0	2,048	28,030

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
Provision for Injuries & Damages - Adj. I	24	(109,736)	(958)	(165)	(1,070)	(2,193)	(2,247)	0	(177)	(2,424)
Deferred FAS 106 Costs - Adj. J	24	273,775	2,391	411	2,670	5,472	5,606	0	442	6,048
Total		74,156	10,487	(18,499)	15,302	7,290	32,706	0	2,533	35,239
Deductions										
Accumulated Def. Inc. Tax										
Plant Additions - Adj. K	41	1,887,637	20,726	1,261	16,882	38,869	45,205	0	2,803	48,008
Normalization - Adj L	24	(25,349)	(221)	(38)	(247)	(506)	(519)	0	(41)	(560)
Def. FAS 106 - Adj. J	24	105,855	924	159	1,032	2,115	2,168	0	171	2,339
Unamortized Loss on Debt - Adj. G	24	(31,526)	(275)	(47)	(307)	(629)	(646)	0	(51)	(697)
Pension - Adj. H	24	846,179	7,390	1,272	8,251	16,913	17,327	0	1,366	18,693
Injuries and Damages - Adj. I	24	(41,583)	(363)	(62)	(405)	(830)	(852)	0	(67)	(919)
Investment Tax Credits - Adj. M	24	(3,488)	(30)	(5)	(34)	(69)	(71)	0	(6)	(77)
Customer Advances for Construction - Adj. N	Direct	(20,926)	(772)		(231)	(1,003)				0
Total		2,716,799	27,379	2,540	24,941	54,860	62,612	0	4,175	66,787
Total Pro Forma Adjustments - Rate Base		512,333	(17,349)	(21,646)	3,652	(35,343)	(24,201)	0	597	(23,604)
Pro Forma Adjustments - Operating Income										
Pro Forma Revenue Adjustments										
Revenue Adjustments - Adj. No. 1-3 to Proforma										
Residential	Direct	(9,792,993)				0				0
Firm General	Direct	(5,461,164)				0				0
Small Interruptible	Direct	(613,776)	0	(613,776)	0	(613,776)				0
Large Interruptible	Direct	(205,865)				0	0	(194,345)	(11,520)	(205,865)
Total Retail Sales Adjustment		(16,073,798)	0	(613,776)	0	(613,776)	0	(194,345)	(11,520)	(205,865)
Unbilled Revenue	26	1,254,664	1,828	25,864	1,853	29,545	0	11,009	677	11,686
Total		(14,819,134)	1,828	(587,912)	1,853	(584,231)	0	(183,336)	(10,843)	(194,179)
Other Revenue - Adj. No. 4	23	47,286	548	0	448	996	1,197	0	74	1,271
Total Pro Forma Revenue Adjustments		(14,771,848)	2,376	(587,912)	2,301	(583,235)	1,197	(183,336)	(10,769)	(192,908)

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
OPERATION & MAINTENANCE EXPENSES										
Cost of Gas - Adj. No. 5	Direct	(13,880,459)	0	(548,094)		(548,094)	0	(92,009)		(92,009)
Labor Expense - Adj. No. 6										
Other Gas Supply	30	2,495	13	5	19	37	34	13	3	50
Production	3	1,334	0	29	0	29	0	0	0	0
Distribution	29	160,710	1,335	278	1,689	3,302	3,376	1,291	283	4,950
Customer Accounting	8	50,020	0	0	28	28	0	0	3	3
Customer Service	8	2,645	0	0	1	1	0	0	0	0
Sales	8	4,111	0	0	2	2	0	0	0	0
A&G	30	48,407	258	94	360	712	652	249	60	961
Total -Labor Expense - Adj. No. 6		269,722	1,606	406	2,099	4,111	4,062	1,553	349	5,964
Benefits Expense - Adj. No. 7	30	(75,501)	(402)	(147)	(562)	(1,111)	(1,017)	(389)	(93)	(1,499)
Vehicles and Work Equip. - Adj. No. 8	30	(6,716)	(36)	(13)	(50)	(99)	(90)	(35)	(8)	(133)
Company Consumption - Adj. No. 9	30	(8,120)	(43)	(16)	(60)	(119)	(109)	(42)	(10)	(161)
Uncollectible Accounts - Adj. No. 10	11	(14,963)	0	0	0	0	0	0	0	0
Advertising - Adj. No. 11	8	(31,656)	0	0	(18)	(18)	0	0	(2)	(2)
Insurance Expense - Adj. No. 12	30	13,839	74	27	103	204	186	71	17	274
Industry Dues - Adj. No. 13	30	(7,138)	(38)	(14)	(53)	(105)	(96)	(37)	(9)	(142)
Regulatory Commission Expense - Adj. No. 14	30	108,300	577	211	806	1,594	1,459	558	134	2,151
Total		53,546	534	195	728	1,457	1,350	515	122	1,987
Total Adjustments to O&M		(13,632,692)	1,738	(547,640)	2,265	(543,637)	4,395	(90,330)	378	(85,557)
DEPRECIATION EXPENSE										
Average Annual Depreciation - Adj. No. 15										
Production Plant	3	1,943	0	42	0	42	0	0	0	0
Distribution Plant	23	1,082,553	12,551	0	10,247	22,798	27,396	0	1,703	29,099
General Plant	41	(4,128)	(45)	(3)	(37)	(85)	(99)	0	(6)	(105)
Common	8	331,936	0	0	185	185	0	0	21	21
Total Average Annual Depreciation Adj. 15		1,412,304	12,506	39	10,395	22,940	27,297	0	1,718	29,015

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	Allocation Factor	Total Montana	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible
TAXES OTHER THAN INCOME										
Ad Valorem Taxes - Adj. No. 16										
Production Plant	3	1,578	0	34	0	34	0	0	0	0
Distribution Plant	23	101,664	1,179	0	962	2,141	2,573	0	160	2,733
General Plant	41	5,288	58	4	47	109	127	0	8	135
Common Plant	41	5,857	64	4	52	120	140	0	9	149
Total Ad Valorem Taxes		114,387	1,301	42	1,061	2,404	2,840	0	177	3,017
Payroll Taxes - Adj. No. 17	31	20,322	108	40	151	299	274	105	25	404
Montana Consumer Counsel & PSC Tax - Adj. 18	26	(167,229)	(244)	(3,447)	(247)	(3,938)	0	(1,467)	(90)	(1,557)
Total Adjustments to Taxes Other than Income		(32,520)	1,165	(3,365)	965	(1,235)	3,114	(1,362)	112	1,864
CURRENT INCOME TAXES										
Interest Annualization - Adj. No. 19	24	(51,878)	(453)	(78)	(506)	(1,037)	(1,062)	0	(84)	(1,146)
Tax Depreciation on Plant Additions - Adj. No. 20	41	2,817,177	30,933	1,881	25,195	58,009	67,465	0	4,183	71,648
Other Tax Deductions - Adj. No. 21	24	(400,022)	(3,493)	(601)	(3,901)	(7,995)	(8,191)	0	(646)	(8,837)
		2,365,277	26,987	1,202	20,788	48,977	58,212	0	3,453	61,665
Net Adjustments to Operating Income		(4,884,217)	(40,020)	(38,148)	(32,112)	(110,280)	(91,821)	(91,644)	(16,430)	(199,895)
Income Taxes on Pro Forma Adj. - Adj. No. 22 0.393875	(Calculated)	(1,923,771)	(15,763)	(15,026)	(12,648)	(43,437)	(36,166)	(36,096)	(6,471)	(78,734)
Elimination of Closing/Filing&Res. - Adj. No. 23	24	1,560,882	13,632	2,346	15,221	31,199	31,962	0	2,519	34,481
Total Adjustments to Current Income Taxes		(362,889)	(2,131)	(12,680)	2,573	(12,238)	(4,204)	(36,096)	(3,952)	(44,253)
DEFERRED INCOME TAXES										
Plant Additions - Adj. No. 20	41	1,109,616	12,184	741	9,924	22,849	26,573	0	1,648	28,221
Elimination of Closing/Filing - Adj. No. 23	24	(1,302,970)	(11,379)	(1,958)	(12,706)	(26,043)	(26,681)	0	(2,103)	(28,784)
Other Tax Deductions	24	38,579	337	58	376	771	790	0	62	852
Total Adjustments to Deferred Income Taxes		(154,775)	1,142	(1,159)	(2,406)	(2,423)	682	0	(393)	289
Total Adjustments:		(2,001,276)	(12,044)	(23,107)	(11,491)	(46,642)	(30,087)	(55,548)	(8,632)	(94,267)

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PRO FORMA AVERAGE PLANT

		Total	Residential		
		Montana	Demand	Energy	Customer
		15,014,099	0	6,097,461	0
1	Dk Throughput	100.000000%	0.000000%	40.611567%	0.000000%
		93,245	48,732	0	0
2	1-Day Peak	100.000000%	52.262320%	0.000000%	0.000000%
		10,129,873	0	6,097,461	0
3	Dk Sales	100.000000%	0.000000%	60.192867%	0.000000%
		85,504	48,225	0	0
5	Peak Day @ Distribution	100.000000%	56.400869%	0.000000%	0.000000%
		78,910	0	0	70,161
8	Average Customers	100.000000%	0.000000%	0.000000%	88.912685%
		78,221	0	0	69,654
9	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	89.047698%
		98,843	0	0	70,161
10	Total Weighted Customers	100.000000%	0.000000%	0.000000%	70.982263%
		78,861	0	0	70,161
11	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	88.967931%
		96,691	0	0	69,654
12	Weighted Customers @ Distribution	100.000000%	0.000000%	0.000000%	72.037729%
		28,623,324	16,143,803	0	0
13	Distribution Mains	100.000000%	56.400867%	0.000000%	0.000000%
		71,677,698	17,432,018	0	28,787,793
15	Distribution Plant	100.000000%	24.320003%	0.000000%	40.162831%

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PRO FORMA AVERAGE PLANT

		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		15,014,099	0	1,119,203	0	0	2,694,623	0
1	Dk Throughput	100.000000%	0.000000%	7.454347%	0.000000%	0.000000%	17.947284%	0.000000%
		93,245	10,098	0	0	20,435		
2	1-Day Peak	100.000000%	10.829535%	0.000000%	0.000000%	21.915384%	0.000000%	0.000000%
		10,129,873	0	1,119,203	0	0	2,694,623	0
3	Dk Sales	100.000000%	0.000000%	11.048539%	0.000000%	0.000000%	26.600758%	0.000000%
		85,504	10,068	0	0	20,290	0	0
5	Peak Day @ Distribution	100.000000%	11.774888%	0.000000%	0.000000%	23.729884%	0.000000%	0.000000%
		78,910	0	0	6,547	0	0	2,153
8	Average Customers	100.000000%	0.000000%	0.000000%	8.296794%	0.000000%	0.000000%	2.728425%
		78,221	0	0	6,517	0	0	2,008
9	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	8.331522%	0.000000%	0.000000%	2.567086%
		98,843	0	0	7,202	0	0	19,593
10	Total Weighted Customers	100.000000%	0.000000%	0.000000%	7.286303%	0.000000%	0.000000%	19.822345%
		78,861	0	0	6,547	0	0	2,153
11	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	8.301949%	0.000000%	0.000000%	2.730120%
		96,691	0	0	7,169	0	0	18,273
12	Weighted Customers @ Distribution	100.000000%	0.000000%	0.000000%	7.414341%	0.000000%	0.000000%	18.898346%
		28,623,324	3,370,364	0	0	6,792,282	0	0
13	Distribution Mains	100.000000%	11.774887%	0.000000%	0.000000%	23.729885%	0.000000%	0.000000%
		71,677,698	3,643,221	0	2,982,141	7,334,281	0	8,039,214
15	Distribution Plant	100.000000%	5.082782%	0.000000%	4.160487%	10.232305%	0.000000%	11.215782%

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ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
1	Dk Throughput	15,014,099 100.000000%	0 0.000000%	904,879 6.026862%	0 0.000000%	0 0.000000%	4,197,933 27.959940%	0 0.000000%
2	1-Day Peak	93,245 100.000000%	2,479 2.658588%	0 0.000000%	0 0.000000%	11,501 12.334173%	0 0.000000%	0 0.000000%
3	Dk Sales	10,129,873 100.000000%	0 0.000000%	218,586 2.157836%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
5	Peak Day @ Distribution	85,504 100.000000%	2,007 2.347259%	0 0.000000%	0 0.000000%	4,914 5.747100%	0 0.000000%	0 0.000000%
8	Average Customers	78,910 100.000000%	0 0.000000%	0 0.000000%	44 0.055760%	0 0.000000%	0 0.000000%	5 0.006336%
9	Average Customers @ Distribution	78,221 100.000000%	0 0.000000%	0 0.000000%	39 0.049859%	0 0.000000%	0 0.000000%	3 0.003835%
10	Total Weighted Customers	98,843 100.000000%	0 0.000000%	0 0.000000%	1,614 1.632893%	0 0.000000%	0 0.000000%	273 0.276196%
11	Average Res. & Firm General Cust.	78,861 100.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
12	Weighted Customers @ Distribution	96,691 100.000000%	0 0.000000%	0 0.000000%	1,431 1.479972%	0 0.000000%	0 0.000000%	164 0.169612%
13	Distribution Mains	28,623,324 100.000000%	671,864 2.347261%	0 0.000000%	0 0.000000%	1,645,011 5.747100%	0 0.000000%	0 0.000000%
15	Distribution Plant	71,677,698 100.000000%	841,724 1.174318%	0 0.000000%	674,762 0.941383%	1,830,529 2.553833%	0 0.000000%	112,015 0.156276%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Residential		
		Montana	Demand	Energy	Customer
		20,137,240	0	0	14,265,755
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	70.842653%
		195,164	95,030	0	0
17	Structures & Improvements	100.000000%	48.692381%	0.000000%	0.000000%
		576,181	324,971	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	56.400853%	0.000000%	0.000000%
		128,222	12,578	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	9.809549%	0.000000%	0.000000%
		2,019,420	0	0	1,405,317
20	Service Regulators	100.000000%	0.000000%	0.000000%	69.590130%
		187,826	82,349	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	43.843238%	0.000000%	0.000000%
		49,082,009	16,143,803	0	14,522,038
22	Mains & Services	100.000000%	32.891488%	0.000000%	29.587293%
		74,788,176	18,041,379	0	30,228,782
23	Pro Forma Distribution Plant	100.000000%	24.123304%	0.000000%	40.419199%
		42,846,658	8,311,325	1,796,137	17,773,079
24	Net Gas Plant in Service	100.000000%	19.397837%	4.192012%	41.480666%
		94,105,843	22,148,487	1,826,714	36,576,724
25	Total Gas Plant in Service	100.000000%	23.535719%	1.941127%	38.867644%
		58,923,014	7,485,900	22,897,748	5,346,268
26	Pro Forma Operating Revenue	100.000000%	12.704543%	38.860449%	9.073310%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		20,137,240	0	0	1,491,459	0	0	3,983,823
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	7.406472%	0.000000%	0.000000%	19.783362%
		195,164	19,840	0	0	39,983	0	0
17	Structures & Improvements	100.000000%	10.165809%	0.000000%	0.000000%	20.486873%	0.000000%	0.000000%
		576,181	67,845	0	0	136,727	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	11.774946%	0.000000%	0.000000%	23.729870%	0.000000%	0.000000%
		128,222	6,539	0	0	5,292	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	5.099749%	0.000000%	0.000000%	4.127217%	0.000000%	0.000000%
		2,019,420	0	0	171,340	0	0	392,446
20	Service Regulators	100.000000%	0.000000%	0.000000%	8.484614%	0.000000%	0.000000%	19.433600%
		187,826	17,192	0	0	34,647	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	9.153152%	0.000000%	0.000000%	18.446328%	0.000000%	0.000000%
		49,082,009	3,370,364	0	1,490,682	6,792,282	0	4,055,391
22	Mains & Services	100.000000%	6.866801%	0.000000%	3.037125%	13.838639%	0.000000%	8.262480%
		74,788,176	3,770,438	0	3,130,058	7,590,660	0	8,441,622
23	Pro Forma Distribution Plant	100.000000%	5.041489%	0.000000%	4.185231%	10.149546%	0.000000%	11.287375%
		42,846,658	1,735,831	329,686	1,843,772	3,496,875	793,760	4,963,270
24	Net Gas Plant in Service	100.000000%	4.051263%	0.769456%	4.303187%	8.161372%	1.852560%	11.583797%
		94,105,843	4,628,944	335,298	3,788,999	9,318,670	807,272	10,214,333
25	Total Gas Plant in Service	100.000000%	4.918870%	0.356299%	4.026316%	9.902329%	0.857834%	10.854090%
		58,923,014	1,551,191	4,279,857	817,066	3,139,095	10,899,890	569,684
26	Pro Forma Operating Revenue	100.000000%	2.632572%	7.263473%	1.386667%	5.327452%	18.498528%	0.966828%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		20,137,240	0	0	340,694	0	0	55,509
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	1.691860%	0.000000%	0.000000%	0.275653%
		195,164	28,566	0	0	11,745	0	0
17	Structures & Improvements	100.000000%	14.636921%	0.000000%	0.000000%	6.018016%	0.000000%	0.000000%
		576,181	13,524	0	0	33,114	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	2.347179%	0.000000%	0.000000%	5.747152%	0.000000%	0.000000%
		128,222	83,999	0	0	19,814	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	65.510599%	0.000000%	0.000000%	15.452886%	0.000000%	0.000000%
		2,019,420	0	0	44,849	0	0	5,468
20	Service Regulators	100.000000%	0.000000%	0.000000%	2.220885%	0.000000%	0.000000%	0.270771%
		187,826	11,588	0	0	42,050	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	6.169540%	0.000000%	0.000000%	22.387742%	0.000000%	0.000000%
		49,082,009	671,864	0	334,068	1,645,011	0	56,506
22	Mains & Services	100.000000%	1.368860%	0.000000%	0.680632%	3.351556%	0.000000%	0.115126%
		74,788,176	867,083	0	707,911	1,892,621	0	117,622
23	Pro Forma Distribution Plant	100.000000%	1.159385%	0.000000%	0.946555%	2.530642%	0.000000%	0.157274%
		42,846,658	374,190	64,389	417,812	877,376	0	69,156
24	Net Gas Plant in Service	100.000000%	0.873324%	0.150278%	0.975133%	2.047712%	0.000000%	0.161403%
		94,105,843	1,069,464	65,485	857,328	2,325,803	0	142,322
25	Total Gas Plant in Service	100.000000%	1.136448%	0.069587%	0.911025%	2.471476%	0.000000%	0.151236%
		58,923,014	85,870	1,214,641	87,000	0	517,004	31,800
26	Pro Forma Operating Revenue	100.000000%	0.145733%	2.061403%	0.147650%	0.000000%	0.877423%	0.053969%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Residential		
		Montana	Demand	Energy	Customer
		2,068,726	400,427	30,249	908,938
27	All Other Dist. Operation Exp.	100.000000%	19.356215%	1.462204%	43.937090%
		622,290	101,233	0	311,315
28	All Other Dist. Maintenance Exp.	100.000000%	16.267817%	0.000000%	50.027319%
		4,322,877	809,761	50,434	1,952,559
29	Distribution O&M	100.000000%	18.731993%	1.166677%	45.168045%
		6,741,800	809,761	208,239	3,828,929
30	O&M Excl. Cost of Gas and A&G	100.000000%	12.011050%	3.088775%	56.793870%
		10,869,310	1,305,518	335,728	6,173,102
31	O&M Excl. Cost of Gas	100.000000%	12.011048%	3.088770%	56.793872%
		38,854,572	7,482,150	16,034,347	0
33	Cost of Gas	100.000000%	19.256807%	41.267595%	0.000000%
		(3,277,536)	(4,038,416)	6,879,780	(6,551,442)
35	Taxable Income	100.000002%	123.215001%	-209.907077%	199.889248%
		6,195,138	1,201,649	279,127	2,548,053
40	Total Tax Deductions & Adjustments	100.000000%	19.396646%	4.505582%	41.129882%
		100,463,465	22,929,037	1,871,521	40,495,499
41	Total Pro Forma Plant	100.000000%	22.823259%	1.862887%	40.308685%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		2,068,726	83,597	5,552	93,663	168,475	13,367	253,829
27	All Other Dist. Operation Exp.	100.000000%	4.040989%	0.268378%	4.527569%	8.143901%	0.646146%	12.269822%
		622,290	21,135	0	32,338	42,593	0	86,937
28	All Other Dist. Maintenance Exp.	100.000000%	3.396326%	0.000000%	5.196613%	6.844558%	0.000000%	13.970496%
		4,322,877	169,055	9,258	201,565	340,698	22,287	545,268
29	Distribution O&M	100.000000%	3.910706%	0.214163%	4.662751%	7.881279%	0.515559%	12.613544%
		6,741,800	169,055	38,224	378,184	340,698	92,026	643,542
30	O&M Excl. Cost of Gas and A&G	100.000000%	2.507565%	0.566970%	5.609540%	5.053517%	1.365006%	9.545552%
		10,869,310	272,555	61,626	609,718	549,282	148,367	1,037,536
31	O&M Excl. Cost of Gas	100.000000%	2.507565%	0.566973%	5.609537%	5.053513%	1.365008%	9.545555%
		38,854,572	1,550,414	2,766,094	0	3,137,522	7,255,016	0
33	Cost of Gas	100.000000%	3.990300%	7.119095%	0.000000%	8.075039%	18.672232%	0.000000%
		(3,277,536)	(843,162)	1,342,799	(390,333)	(1,698,817)	3,540,693	(2,024,900)
35	Taxable Income	100.000002%	25.725484%	-40.969771%	11.909343%	51.832139%	-108.029111%	61.781167%
		6,195,138	250,950	50,995	264,333	505,563	123,581	711,563
40	Total Tax Deductions & Adjustments	100.000000%	4.050757%	0.823146%	4.266781%	8.160641%	1.994806%	11.485830%
		100,463,465	4,791,939	343,523	4,171,033	9,647,075	827,074	10,763,048
41	Total Pro Forma Plant	100.000000%	4.769832%	0.341938%	4.151791%	9.602570%	0.823258%	10.713395%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA AVERAGE PLANT

		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		2,068,726	17,296	4,489	21,076	43,405	20,825	3,538
27	All Other Dist. Operation Exp.	100.000000%	0.836070%	0.216993%	1.018791%	2.098151%	1.006658%	0.171023%
		622,290	5,045	0	7,338	13,145	0	1,211
28	All Other Dist. Maintenance Exp.	100.000000%	0.810715%	0.000000%	1.179193%	2.112359%	0.000000%	0.194604%
		4,322,877	35,921	7,484	45,443	90,823	34,722	7,599
29	Distribution O&M	100.000000%	0.830951%	0.173125%	1.051221%	2.100985%	0.803215%	0.175786%
		6,741,800	35,921	13,141	50,187	90,823	34,722	8,348
30	O&M Excl. Cost of Gas and A&G	100.000000%	0.532810%	0.194918%	0.744415%	1.347162%	0.515026%	0.123824%
		10,869,310	57,913	21,186	80,913	146,427	55,980	13,459
31	O&M Excl. Cost of Gas	100.000000%	0.532812%	0.194916%	0.744417%	1.347160%	0.515028%	0.123826%
		38,854,572	91,968	537,061	0	0	0	0
33	Cost of Gas	100.000000%	0.236698%	1.382234%	0.000000%	0.000000%	0.000000%	0.000000%
		(3,277,536)	(184,097)	673,087	(124,890)	(412,600)	547,141	7,621
35	Taxable Income	100.000002%	5.616933%	-20.536372%	3.810484%	12.588725%	-16.693669%	-0.232522%
		6,195,138	53,770	9,955	59,900	125,785	0	9,914
40	Total Tax Deductions & Adjustments	100.000000%	0.867939%	0.160691%	0.966887%	2.030383%	0.000000%	0.160029%
		100,463,465	1,103,089	67,091	898,480	2,405,871	0	149,185
41	Total Pro Forma Plant	100.000000%	1.098000%	0.066781%	0.894335%	2.394772%	0.000000%	0.148497%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ALLOCATION OF REVENUE INCREASE & RESULTS OF PROPOSED RATE DESIGN
Pro Forma 2012

	Billing Determinants 1/					
Rate Class	Customers	Dk	Basic Service Charge	Distribution Delivery	Gas Costs	Total Revenues
Residential	70,161	6,097,461	$5,346,268	$6,865,741	$23,517,907	$35,729,916
Firm General						
Small Firm General	6,547	1,119,203	817,066	1,514,282	4,316,766	6,648,114
Large Firm General	2,153	2,694,623	569,683	3,645,825	10,393,161	14,608,669
Total Firm General	8,700	3,813,826	1,386,749	5,160,107	14,709,927	21,256,783
Small Interruptible						
Sales	9	218,586	13,500	162,191	629,091	804,782
Transportation	35	686,293	73,500	509,229	0	582,729
Total Small IT	44	904,879	87,000	671,420	629,091	1,387,511
Large Interruptible						
Sales	0	0	0	0	0	0
Transportation	5	4,197,933	31,800	517,004	0	548,804
Total Large IT	5	4,197,933	31,800	517,004	0	548,804
Total Montana	78,910	15,014,099	$6,851,817	$13,214,272	$38,856,925	$58,923,014

	Embedded Cost of Service Before Increase 2/			Marginal Cost of Service Apportioned to Embedded 3/	
Rate Class	Operating Income	Rate Base	Rate of Return	Marginal Cost of Service	% of Marginal Cost of Service
Residential	$80,235	$28,821,161	0.28%	$43,168,363	68.75%
Small Firm General	472,698	4,159,479	11.36%	7,015,706	11.17%
Large Firm General	694,890	9,334,725	7.44%	11,856,511	18.88%
Small Interruptible	271,907	674,462	40.31%	717,270	1.14%
Large Interruptible	107,294	770,007	13.93%	36,754	0.06%
Total Montana	$1,627,024	$43,759,834	3.72%	$62,794,604	

1/ Rule 38.5.164, Statement H, Page 3.
2/ Rule 38.5.176, Statement L, Schedule L-1, Page 4.
3/ Exhibit No.____(TAA-3).

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ALLOCATION OF REVENUE INCREASE & RESULTS OF PROPOSED RATE DESIGN
Pro Forma 2012

	Revenue Increase Based on Embedded Cost of Service				Revenue Increase Based on Marginal Cost of Service			
RATE CLASS	Increase In Revenue 1/	% Increase	Operating Income	Rate of Return	Increase In Revenue 2/	Miscellaneous Revenue 3/	Increase In Revenue Exclude Misc. Revenue	% Increase
Residential	$3,916,669	10.96%	$2,446,628	8.49%	$7,438,447	$280,482	$7,157,965	20.03%
Small Firm General	(197,953)	-2.98%	353,098	8.49%	367,592	37,585	330,007	4.96%
Large Firm General	161,432	1.11%	792,425	8.49%	(2,752,158)	81,820	(2,833,978)	-13.33%
Small Interruptible	(355,276)	-25.61%	57,255	8.49%	(670,241)	7,553	(677,794)	-48.85%
Large Interruptible	(69,394)	-12.64%	65,366	8.49%	(512,050)	8,672	(520,722)	-94.88%
Total Montana	$3,455,478	5.86%	$3,714,772	8.49%	$3,871,590	$416,112	$3,455,478	5.86%

	Target Rate Design				Rate Design Results			
RATE CLASS	Increase In Revenue	% Increase	Operating Income	Rate of Return	Increase In Revenue	Total Revenues	% Incr	Rate of Return
Residential 4/	$2,834,005	7.93%	$1,792,498	6.22%	$2,836,325	$38,566,241	7.94%	6.22%
Small Firm General 5/	186,147				255,192	6,903,306		
Large Firm General 5/	409,043				339,234	14,947,903		
	595,190	2.80%	1,527,193	11.32%	594,426	21,851,209	2.80%	11.31%
Small Interruptible 6/	18,834	1.36%	283,286	42.00%	19,161	1,406,672	1.38%	42.03%
Large Interruptible 7/	7,449	1.36%	111,795	14.52%	7,500	556,304	1.37%	14.52%
Total Montana	$3,455,478	5.86%	$3,714,772	8.49%	$3,457,412	$62,380,426	5.87%	8.49%

1/ Rule 38.5.176, Statement L, Schedule L-1.
2/ Exhibit No________ (TAA-3), Page 1.
3/ Rule 38.5.176, Statement L, Schedule L-1, Pages 4 -5.
4/ Rule 38.5.177, Statement M, page 3.
5/ Rule 38.5.177, Statement M, page 5.
6/ Rule 38.5.177, Statement M, page 7.
7/ Rule 38.5.177, Statement M, page 7.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE DESIGN & RECONCILIATION
RESIDENTIAL GAS SERVICE - RATE 60
Pro Forma 2012

			Current		Proposed 1/	
			Rate	Amount	Rate	Amount
Residential Rate 60						
Basic Service Charge	70,161	Customers	$6.35	$5,346,268	$0.35	$8,963,068
Distribution Charge	6,097,461	Dk	1.126	6,865,741	0.998	6,085,266
Cost of Gas	6,097,461	Dk	3.857	23,517,907	3.857	23,517,907
Total Revenue Rate 60				$35,729,916		$38,566,241

Total Distribution Revenues Per Design	$15,048,334
Target Distribution Revenues	15,046,014
Difference	$2,320

Current Non-Gas Revenues	$12,212,009
Proposed Revenue Increase	2,834,005
Total Revenue Requirement	$15,046,014
Less:	
Basic Service Charge Revenues	8,963,068
Remaining Revenues To Be Collected	6,082,946
Total Rate 60 Consumption	6,097,461
Distribution Delivery Charge	$0.998

1/ Proposing to move Basic Service Charge from monthly to a daily charge.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE DESIGN & RECONCILIATION
FIRM GENERAL GAS SERVICE - RATES 70 & 72
Pro Forma 2012

			Current		Proposed 1/	
			Rate	Amount	Rate	Amount
Firm General Rate 70						
Basic Service Chg < 500	6,547	Customers	$10.40	$817,066	$0.40	$955,862
Basic Service Chg > 500	2,153	Customers	22.05	569,683	0.80	628,676
Subtotal						
Distribution Delivery < 500	1,119,203	Dk	1.353	1,514,282	1.457	1,630,678
Distribution Delivery > 500	2,694,623	Dk	1.353	3,645,825	1.457	3,926,066
Cost of Gas < 500	1,119,203	Dk	3.857	4,316,766	3.857	4,316,766
Cost of Gas > 500	2,694,623	Dk	3.857	10,393,161	3.857	10,393,161
Total Rates 70 and 72 Revenue				$21,256,783		$21,851,209

Total Distribution Revenues Per Design	$7,141,282
Target Distribution Revenues	7,142,046
Difference	($764)

Current Non-Gas Revenues	$6,546,856
Proposed Revenue Increase	595,190
Total Revenue Requirement	$7,142,046
Less:	
Basic Service Charge Revenues	1,584,538
Remaining Revenues To Be Collected	5,557,508
Total Rates 70 & 72 Consumption	3,813,826
Distribution Delivery Charge	$1.457

1/ Proposing to move Basic Service Charge from monthly to a daily charge.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE DESIGN & RECONCILIATION
SMALL INTERRUPTIBLE - RATES 71 & 81
Pro Forma 2012

			Current		Proposed	
			Rate	Amount	Rate	Amount
Basic Service Charge						
Rate 71 Sales	9	Customers	$125.00	$13,500	$175.00	$18,900
Rate 81 Transport	35	Customers	175.00	73,500	225.00	94,500
Subtotal	44			87,000		$113,400
Distribution Delivery						
Rate 71 Sales	218,586	dk	$0.742	162,191	$0.734	160,442
Rate 81 Transport	686,293	dk	0.742	509,229	0.734	503,739
Cost of Gas	218,586	dk	2.878	629,091	2.878	629,091
Total Revenue				$1,387,511		$1,406,672

Total Distribution Revenues Per Design	$777,581
Target Distribution Revenues	777,254
Difference	$327

Current Non-Gas Revenues	$758,420
Proposed Revenue Increase	18,834
Total Revenue Requirement	$777,254
Less:	
Basic Serivce Charge Revenue	113,400
Remaining Revenues To Be Collected	$663,854
Total Throughput Rates 71 & 81	904,879
Distribution Delivery Charge	$0.734

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
RATE DESIGN & RECONCILIATION
LARGE INTERRUPTIBLE SERVICE - RATE 82 & 85
Pro Forma 2012

CLASS			Current Rate	Current Amount	Proposed Rate	Proposed Amount
Basic Service Charge						
Rate 85 Sales	0	Customers	$480.00	$0	$605.00	$0
Rate 82 Transport	5	Customers	530.00	31,800	655.00	39,300
Subtotal				31,800		39,300
Distribution Delivery						
Rate 85 Sales	0	dk	0.500	$0	0.500	$0
Rate 85 Sales	0	dk	1/	0	1/	0
Rate 82 Transport	74,017	dk	0.500	37,009	0.500	37,009
Rate 82 Transport	4,123,916	dk	1/	479,995	1/	479,995
Cost of Gas	0	dk	0.000	0	0.000	0
Total Revenue				$548,804		$556,304

Total Distribution Revenues Per Design	$556,304
Target Distribution Revenues	556,253
Difference	$51

Revenue Requirement	$548,804
Less: Distribution Delivery Revenues	(517,004)
Proposed Revenue Increase	7,449
Total Revenue Requirement	$39,249
Bills	60
Basic Service Charge	$654.16
Proposed Basic Service Charge - Rate 85 Sales	$605.00
Proposed Basic Service Charge - Rate 82 Transport	$655.00

1/ Flexed contract rates.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - Montana
REVENUE RECONCILIATION
LARGE INTERRUPTIBLE SERVICE - RATES 82 & 85
Pro Forma 2012

Large Interruptible Transportation	
Base Rate Revenues	$39,300
Transportation Revenues - @ Ceiling	37,009
Transportation Revenues - Flexed	479,995
Total Transportation Revenues	$556,304
Total Large Interruptible Revenues Per Design	$556,304
Total Large Interruptible Target Revenues	556,253
Difference	$51

Flexed Contracts

Customer ID	Bills	Base Rev	Dk	Rate	Dist Rev	Total Rev
1	12	$6,360	2,075,491	$0.050	$103,775	$110,135
2	12	6,360	1,564,411	0.203	317,575	323,935
3	12	6,360	155,205	0.166	25,764	32,124
4	12	6,360	328,809	0.100	32,881	39,241
Total	48	$25,440	4,123,916		$479,995	$505,435

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Bill Comparison Annual Effects
Residential Gas Service Rate 60

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Use	Range	Customers	Total Customers	Average Use
< than $0	124	124	363	< than 0%	124	124	363
$1 to $25	18,247	18,371	37	1% to 5%	12,338	12,462	133
$26 to $50	65,879	84,250	84	6% to 10%	39,611	52,073	84
$51 to $75	433	84,683	6	11% to 25%	27,482	79,555	77
$76 to $100	0	84,683		26% to 50%	3,503	83,058	7
$101 to $200	0	84,683		51% to 75%	1,625	84,683	0
$201 to $300	0	84,683		76% to 100%	0	84,683	
$301 to $400	0	84,683		> than 100%	0	84,683	
$401 to $500	0	84,683					
$501 to $600	0	84,683					
$601 to $700	0	84,683					
$701 to $800	0	84,683					
> than $801	0	84,683					

Current Rate 60

Basic Service Charge	$6.35	
Distribution Delivery Charge	1.126	per Dk
Cost of Gas	3.857	per Dk

Proposed Rate 60

Basic Service Charge	$10.64	
Distribution Delivery Charge	0.998	per Dk
Cost of Gas	3.857	per Dk

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Bill Comparison Annual Effects
Firm General Gas Service Rate 70 (Small Meters)

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Use	Range	Customers	Total Customers	Average Use
< than $0	0	0	0	< than 0%	0	0	0
$1 to $25	1,941	1,941	27	1% to 5%	4,286	4,286	239
$26 to $50	4,215	6,156	130	6% to 10%	2,440	6,726	50
$51 to $75	912	7,068	367	11% to 25%	646	7,372	156
$76 to $100	213	7,281	596	26% to 50%	0	7,372	
$101 to $200	86	7,367	964	51% to 75%	0	7,372	
$201 to $300	4	7,371	1,997	76% to 100%	0	7,372	
$301 to $400	1	7,372	2,838	> than 100%	0	7,372	
$401 to $500	0	7,372					
$501 to $600	0	7,372					
$601 to $700	0	7,372					
$701 to $800	0	7,372					
> than $801	0	7,372					

Current Rate 70

Basic Service Charge	$10.40	
Distribution Delivery Charge	1.353	per Dk
Cost of Gas	3.857	per Dk

Proposed Rate 70

Basic Service Charge	$12.17	
Distribution Delivery Charge	1.457	per Dk
Cost of Gas	3.857	per Dk

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
Bill Comparison Annual Effects
Firm General Gas Service Rate 70 (Large Meters)

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Use	Range	Customers	Total Customers	Average Use
< than $0	0	0	0	< than 0%	0	0	0
$1 to $25	106	106	55	1% to 5%	2,135	2,135	1,250
$26 to $50	243	349	133	6% to 10%	76	2,211	30
$51 to $75	421	770	354	11% to 25%	24	2,235	1,195
$76 to $100	353	1,123	572	26% to 50%	0	2,235	
$101 to $200	691	1,814	1,089	51% to 75%	0	2,235	
$201 to $300	207	2,021	2,024	76% to 100%	0	2,235	
$301 to $400	95	2,116	3,033	> than 100%	0	2,235	
$401 to $500	39	2,155	4,026				
$501 to $600	25	2,180	4,914				
$601 to $700	12	2,192	5,934				
$701 to $800	12	2,204	6,917				
> than $801	31	2,235	12,478				

Current Rate 70

Basic Service Charge	$22.05	
Distribution Delivery Charge	1.353	per Dk
Cost of Gas	3.857	per Dk

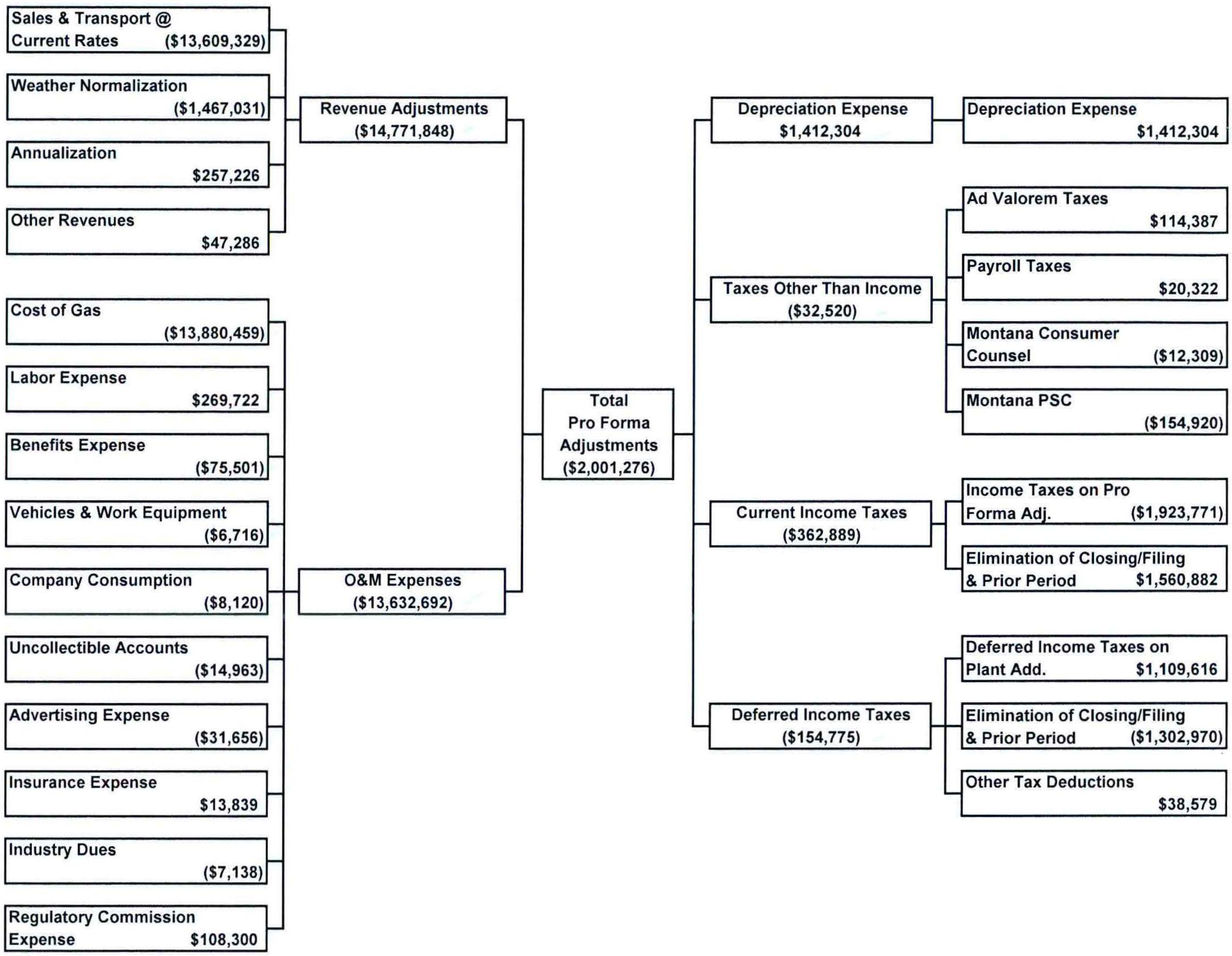
Proposed Rate 70

Basic Service Charge	$24.33	
Distribution Delivery Charge	1.457	per Dk
Cost of Gas	3.857	per Dk

MONTANA-DAKOTA UTILITIES CO.
DESCRIPTION OF UTILITY OPERATIONS

Please refer to the testimony of Mr. Jay Skabo, Vice President - Operations of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., for a description of its Montana utility operations.

MONTANA-DAKOTA UTILITIES CO.
FLOWCHART OF PRO FORMA ADJUSTMENTS TO OPERATING INCOME



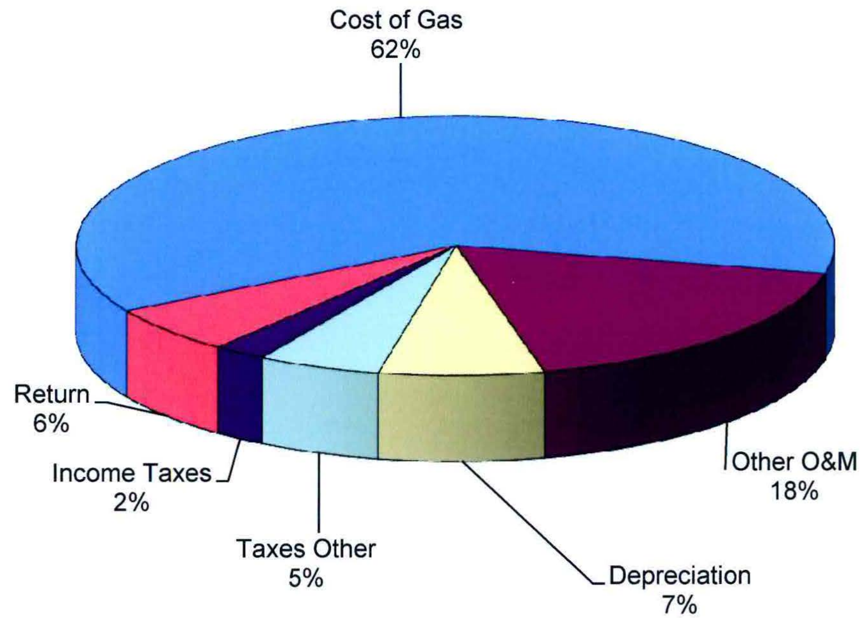
MONTANA-DAKOTA UTILITIES CO.
FLOWCHART OF PRO FORMA ADJUSTMENTS TO RATE BASE

- **Total Pro Forma Adjustments $512,333**
  - **Gas Plant in Service $3,154,976**
    - Plant Additions $6,357,622
    - Accumulated Reserve for Depreciation on Plant Additions $3,202,646
  - **Additions $74,156**
    - Materials & Supplies $99,695
    - Gas in Underground Storage ($855,502)
    - Prepaid Insurance $93,808
    - Prepaid Demand & Commodity ($642,915)
    - Unamortized Loss on Debt ($53,806)
    - Provision for Pensions & Benefits $1,268,837
    - Provision for Injuries & Damages ($109,736)
    - Deferred FAS 106 Costs $273,775
  - **Deductions $2,716,799**
    - Accumulated Def. Inc. Tax - Plant Additions $1,887,637
    - Accumulated Def. Inc. Tax - Normalization ($25,349)
    - Accumulated Def. Inc. Tax - Def. FAS 106 $105,855
    - Accumulated Def. Inc. Tax - Unamortized Loss on Debt ($31,526)
    - Accumulated Def. Inc. Tax - Pensions & Benefits $846,179
    - Accumulated Def. Inc. Tax - Injuries and Damages ($41,583)
    - ITCs ($3,488)
    - Customer Advances for Construction ($20,926)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
SUMMARY OF INCOME STATEMENTS
AUTHORIZED 1994 - PRO FORMA

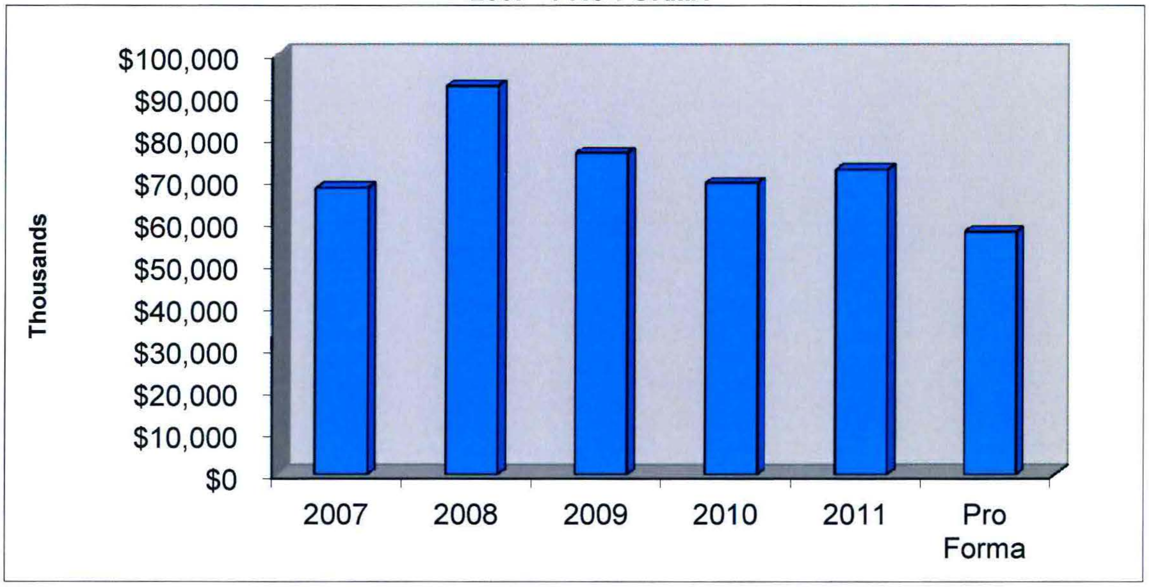
	Pro Forma	2011	2010	2009	2008	2007	Authorized 1994
Revenues							
Sales	$57,791,481	$72,489,259	$69,253,780	$76,346,192	$92,363,464	$68,060,399	$48,546,724
Transportation	1,131,533	1,252,889	1,269,502	1,124,811	1,200,721	1,309,619	679,222
Other	416,112	368,826	321,236	259,498	346,495	247,473	184,769
Total Revenues	59,339,126	74,110,974	70,844,518	77,730,501	93,910,680	69,617,491	49,410,715
O&M Expenses							
Cost of Gas	38,854,572	52,735,031	51,138,361	57,355,038	74,434,088	50,728,699	33,651,397
Other Gas Supply	76,100	73,609	89,297	70,111	79,239	76,793	50,323
Production	189,880	188,558	0	0	0	0	0
Distribution	4,472,702	4,322,878	4,351,984	4,245,853	4,761,896	4,413,993	3,555,284
Customer Accounting	1,981,143	1,948,083	1,832,901	2,071,005	2,322,040	2,272,555	1,936,973
Customer Service & Info.	91,740	89,100	55,796	71,149	100,475	62,266	29,584
Sales	123,410	119,573	137,024	168,744	235,578	233,097	600,403
Administrative & General	4,182,103	4,127,510	3,410,276	3,875,221	4,620,544	4,599,672	3,076,745
Other O&M	11,117,078	10,869,311	9,877,278	10,502,083	12,119,772	11,658,376	9,249,312
Total O&M	49,971,650	63,604,342	61,015,639	67,857,121	86,553,860	62,387,075	42,900,709
Depreciation & Amortization	4,423,602	3,011,298	2,815,887	2,879,850	2,781,508	2,577,959	1,781,674
Taxes Other Than Income							
Ad Valorem	2,618,463	2,504,076	2,399,556	2,250,305	2,176,243	1,742,464	1,185,918
O&M Related	467,859	447,537	498,654	426,013	471,820	474,600	438,243
Revenue	188,681	355,910	227,649	252,245	385,880	215,722	128,015
Other	496	496	480	385	437	482	11,416
Total Taxes Other	3,275,499	3,308,019	3,126,339	2,928,948	3,034,380	2,433,268	1,763,592
Income Taxes							
Current Income Taxes	(3,293,075)	(2,930,186)	(1,010,661)	2,627,193	(3,424,088)	1,230,066	5,911,351
Deferred Income Taxes	3,334,426	3,489,201	1,815,319	(1,738,765)	3,327,157	(1,147,642)	(5,110,756)
Total Income Taxes	41,351	559,015	804,658	888,428	(96,931)	82,424	800,595
Amortization of Pre-1974 Debt							14,000
Net Income	$1,627,024	$3,628,300	$3,081,995	$3,176,154	$1,637,863	$2,136,765	$2,178,145

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUE REQUIREMENTS



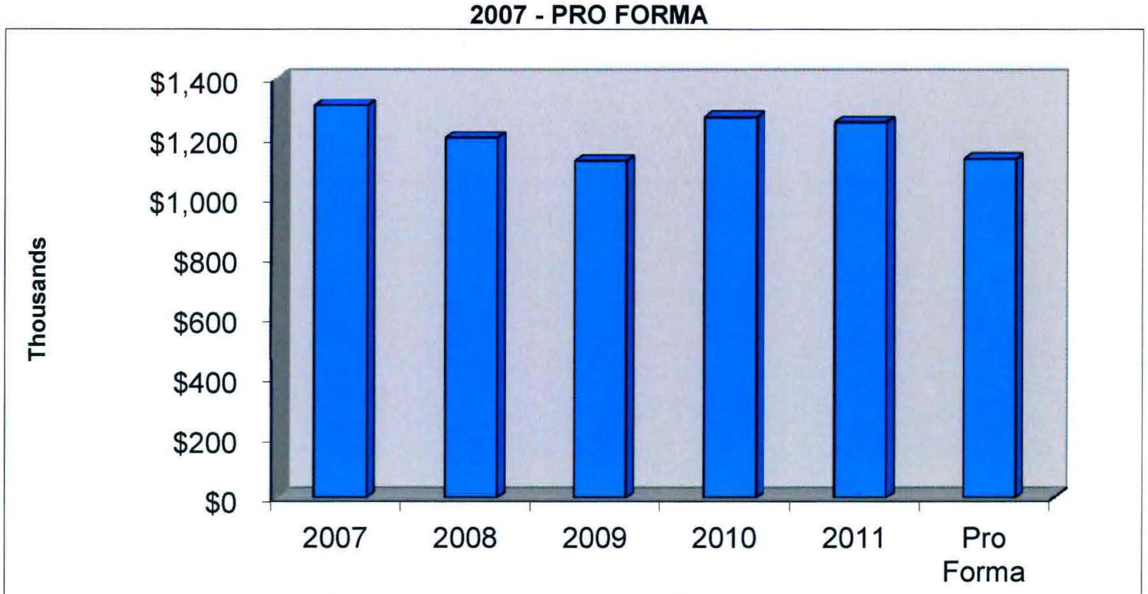
Revenue Requirement	
Cost of Gas	$38,854,572
Other O&M	11,117,078
Depreciation	4,423,602
Taxes Other	3,286,557
Income Taxes	1,398,023
Return	3,714,772
Miscellaneous Revenue	(416,112)
Total	$62,378,492

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF SALES REVENUE
2007 - PRO FORMA**



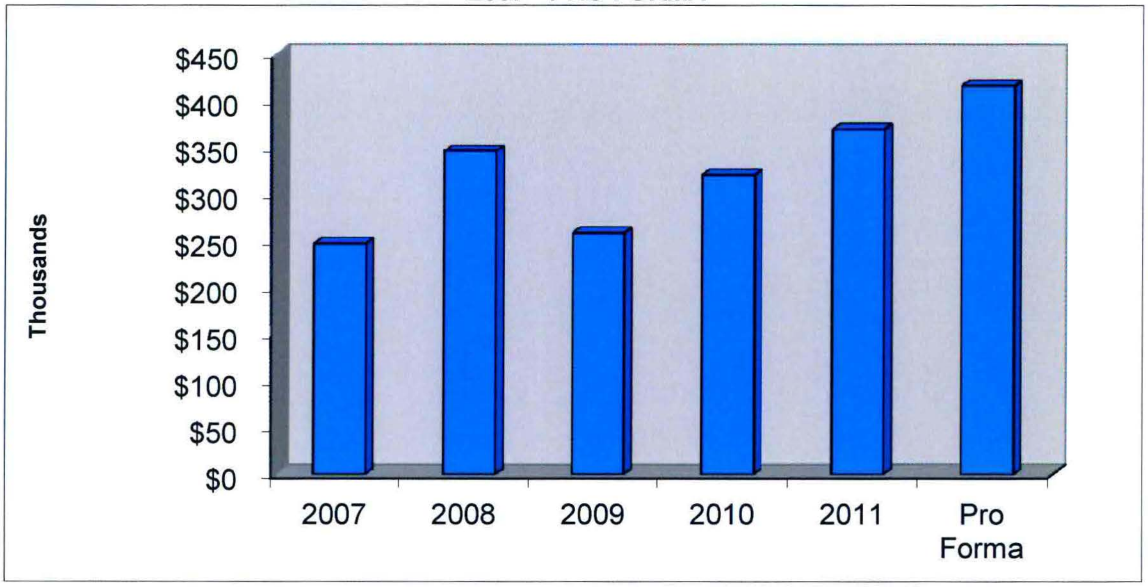
Sales Revenue					
2007	2008	2009	2010	2011	Pro Forma
$68,060,399	$92,363,464	$76,346,192	$69,253,780	$72,489,259	$57,791,481

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF TRANSPORTATION REVENUE
2007 - PRO FORMA**



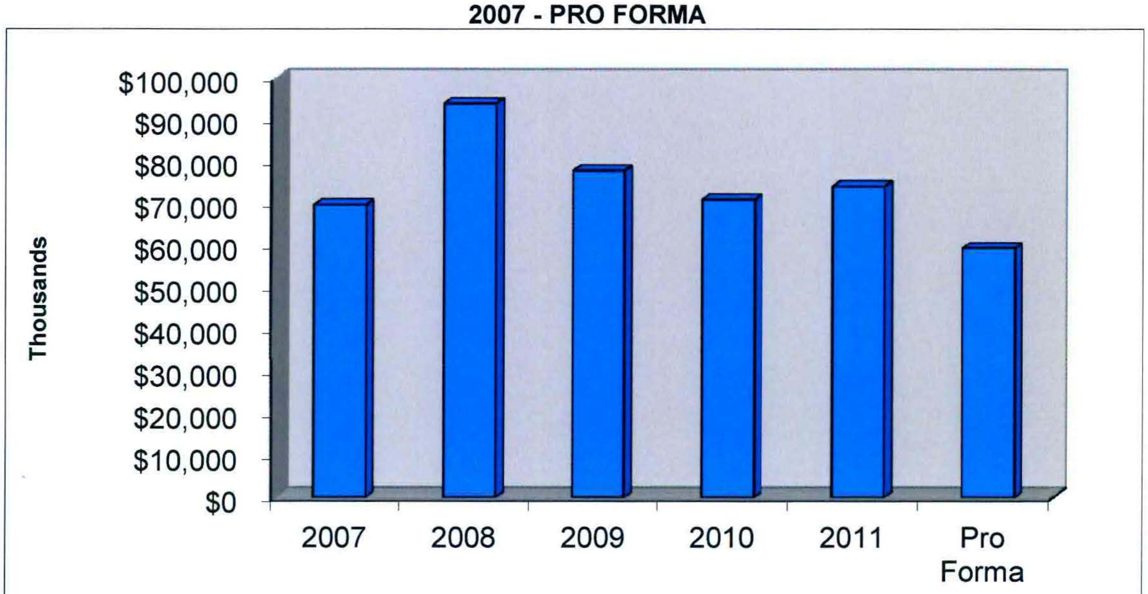
Transportation Revenue					
2007	2008	2009	2010	2011	Pro Forma
$1,309,619	$1,200,721	$1,124,811	$1,269,502	$1,252,889	$1,131,533

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OTHER REVENUE
2007 - PRO FORMA



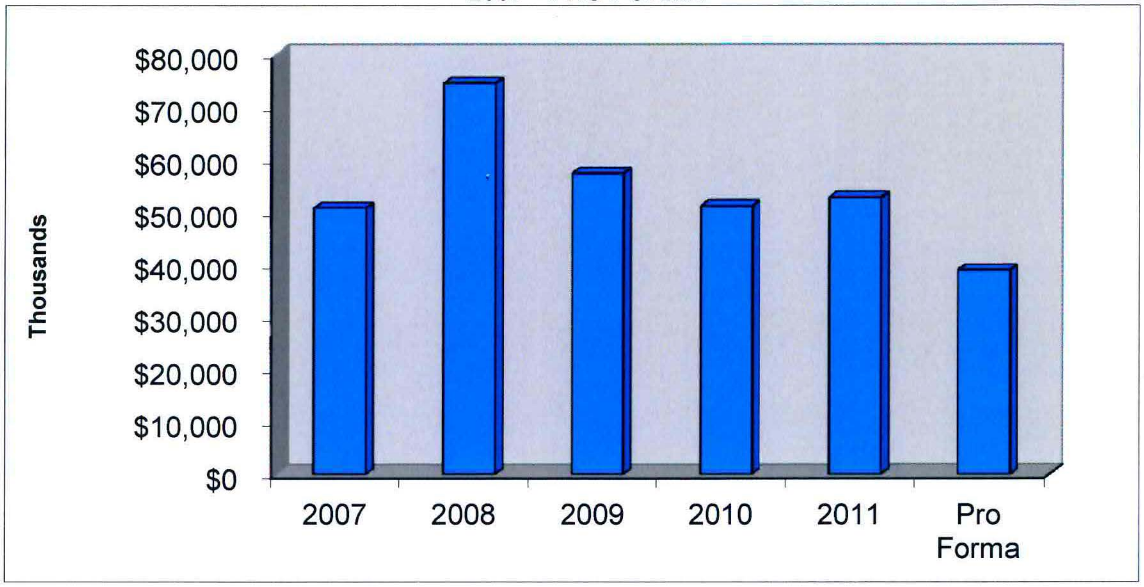
Other Revenue					
2007	2008	2009	2010	2011	Pro Forma
$247,473	$346,495	$259,498	$321,236	$368,826	$416,112

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF TOTAL REVENUE
2007 - PRO FORMA



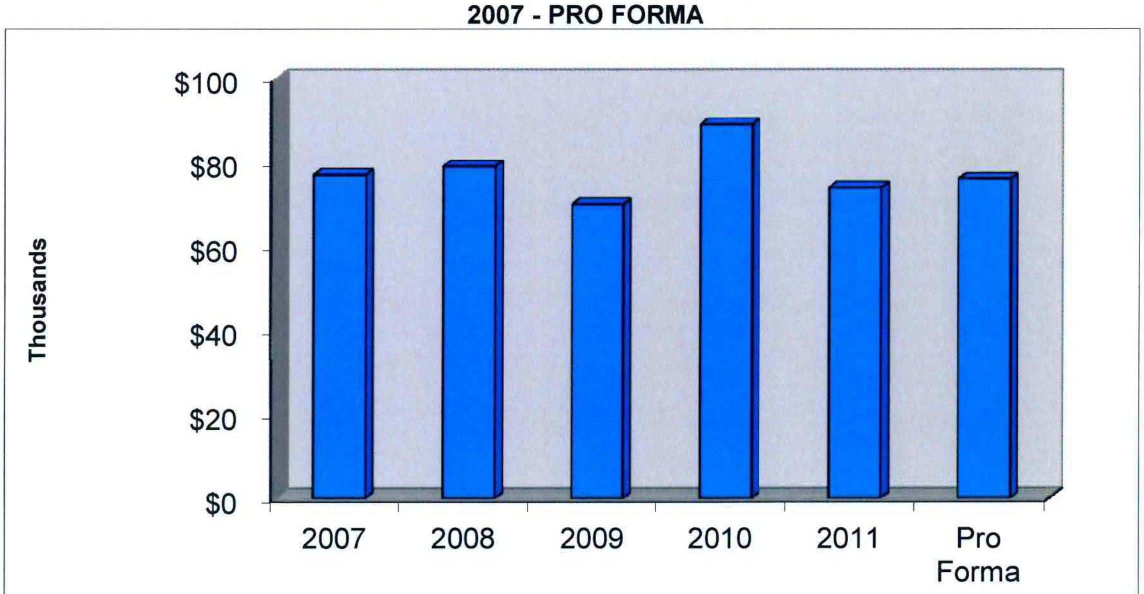
Total Revenue					
2007	2008	2009	2010	2011	Pro Forma
$69,617,491	$93,910,680	$77,730,501	$70,844,518	$74,110,974	$59,339,126

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF COST OF GAS
2007 - PRO FORMA



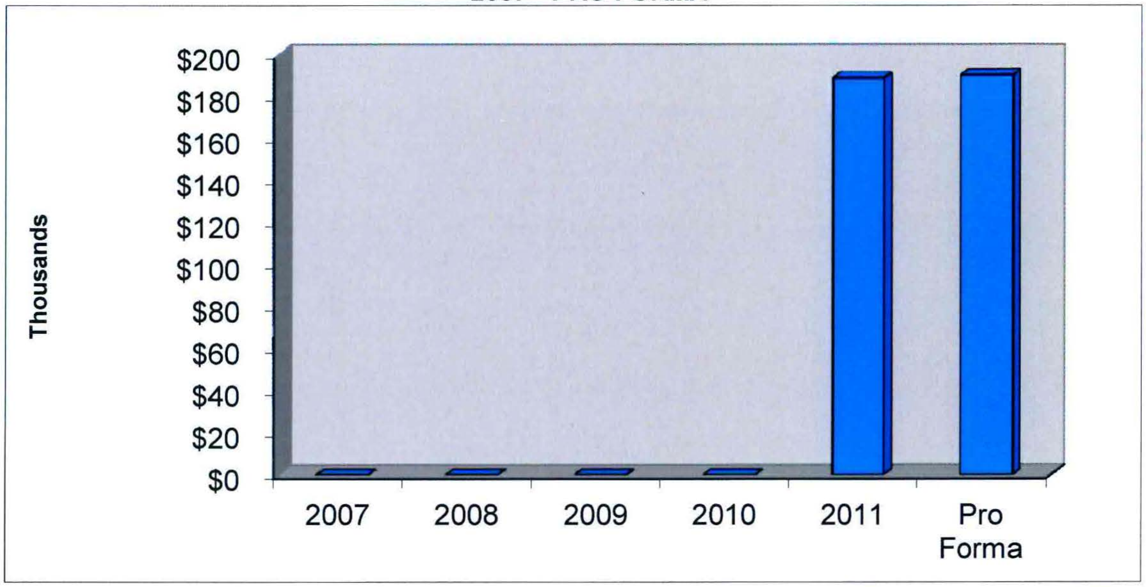
Cost of Gas					
2007	2008	2009	2010	2011	Pro Forma
$50,728,699	$74,434,088	$57,355,038	$51,138,361	$52,735,031	$38,854,572

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OTHER GAS SUPPLY O&M
2007 - PRO FORMA



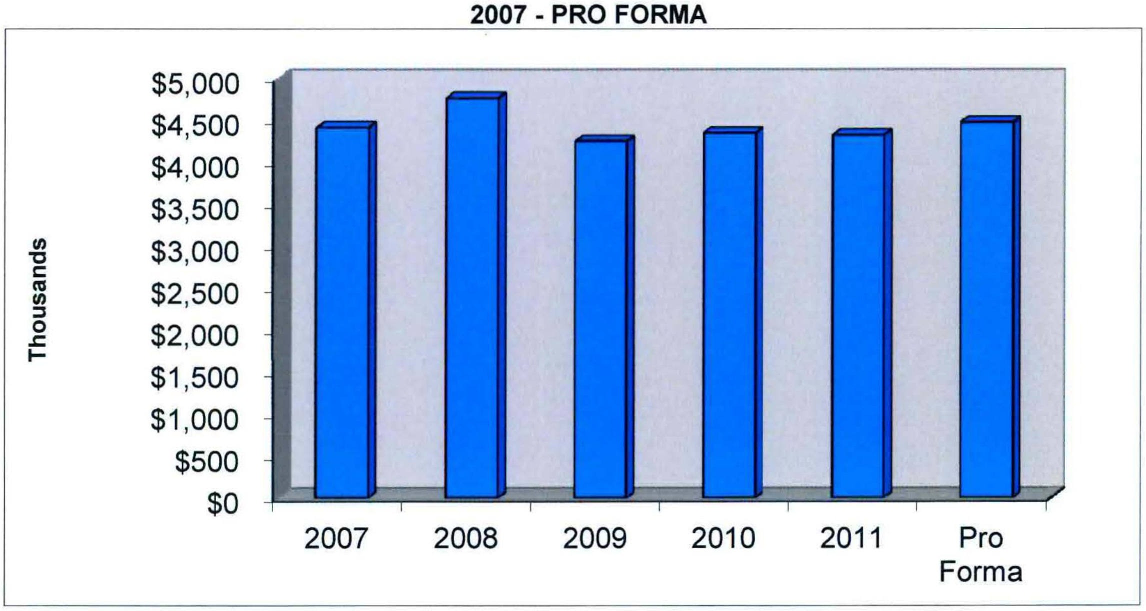
Other Gas Supply O&M					
2007	2008	2009	2010	2011	Pro Forma
$76,793	$79,239	$70,111	$89,297	$73,609	$76,100

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRODUCTION O&M
2007 - PRO FORMA**



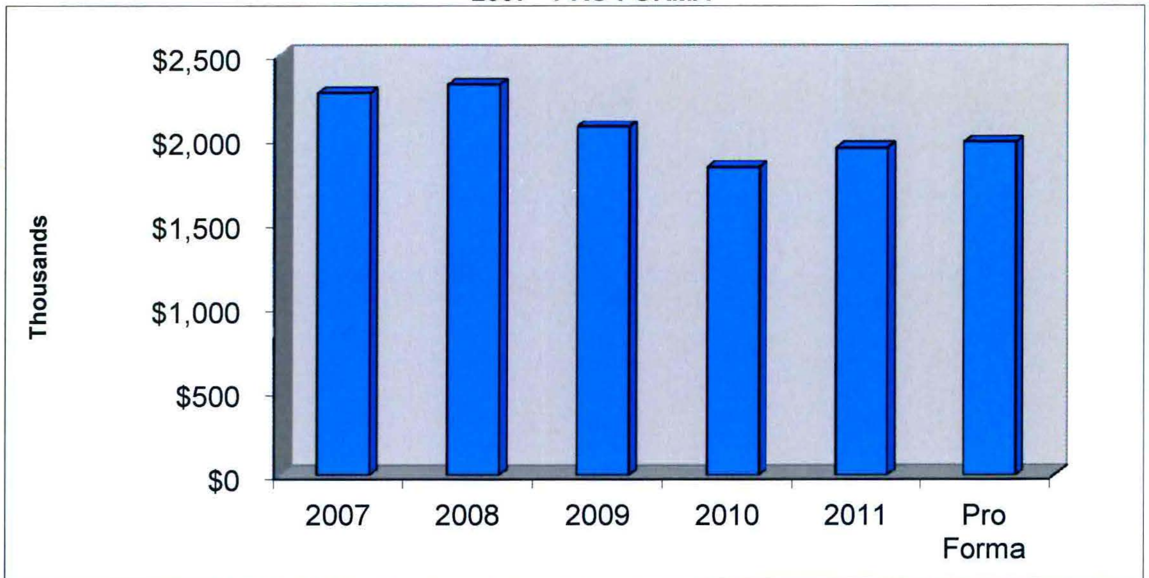
Production O&M					
2007	2008	2009	2010	2011	Pro Forma
$0	$0	$0	$0	$188,558	$189,880

**MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DISTRIBUTION O&M
2007 - PRO FORMA**



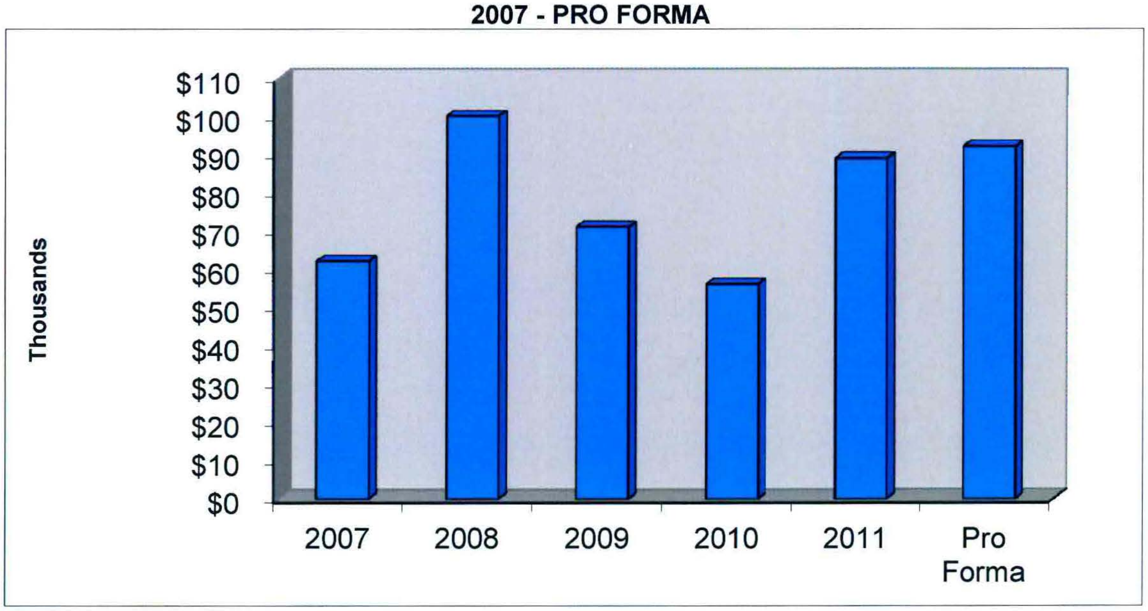
Distribution O&M					
2007	2008	2009	2010	2011	Pro Forma
$4,413,993	$4,761,896	$4,245,853	$4,351,984	$4,322,878	$4,472,702

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF CUSTOMER ACCOUNTING O&M
2007 - PRO FORMA



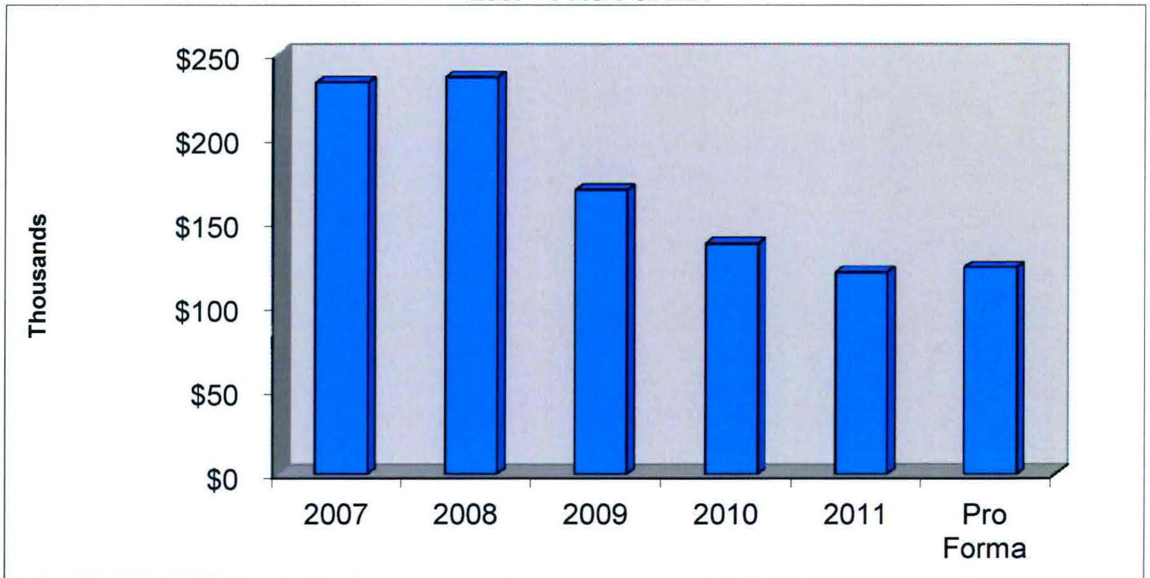
Customer Accounting O&M					
2007	2008	2009	2010	2011	Pro Forma
$2,272,555	$2,322,040	$2,071,005	$1,832,901	$1,948,083	$1,981,143

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF CUSTOMER SERVICE & INFORMATION O&M
2007 - PRO FORMA



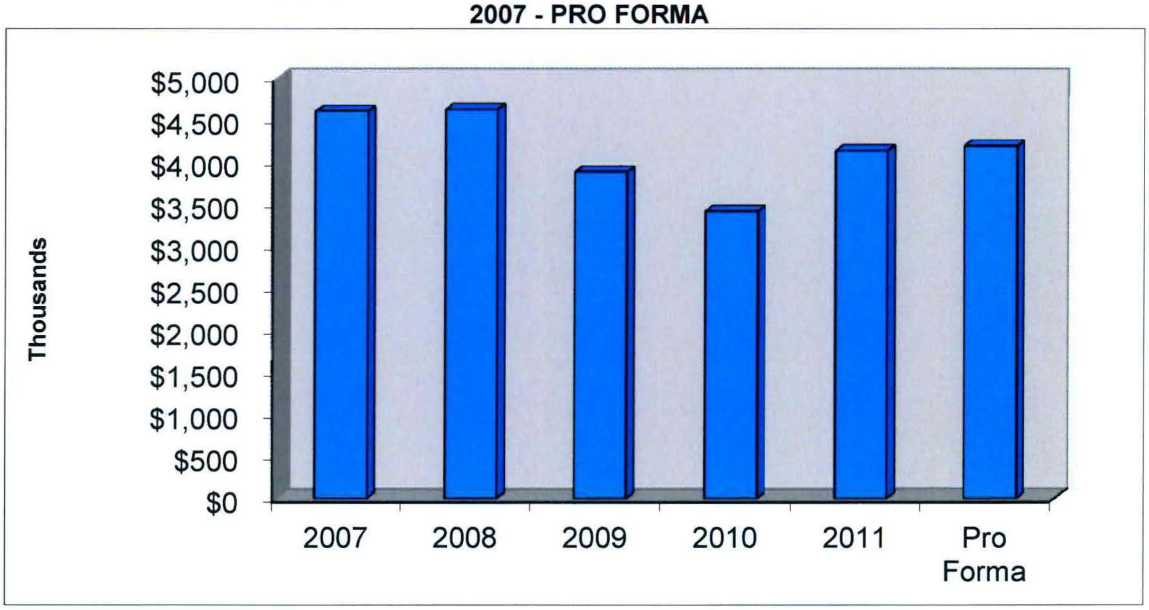
Customer Service & Information O&M					
2007	2008	2009	2010	2011	Pro Forma
$62,266	$100,475	$71,149	$55,796	$89,100	$91,740

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF SALES O&M
2007 - PRO FORMA



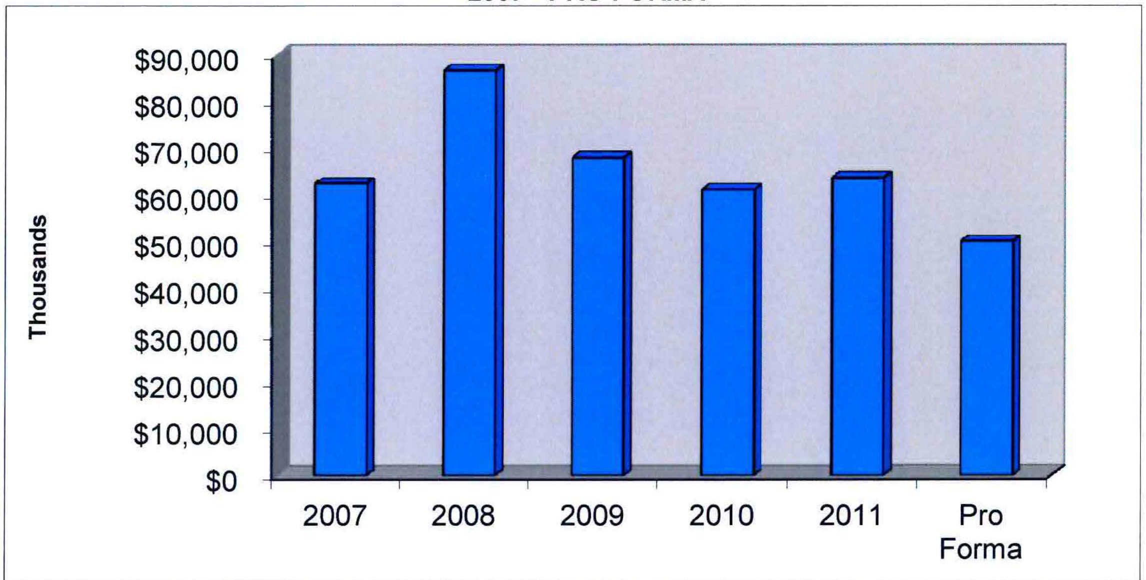
Sales O&M					
2007	2008	2009	2010	2011	Pro Forma
$233,097	$235,578	$168,744	$137,024	$119,573	$123,410

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADMINISTRATIVE & GENERAL O&M
2007 - PRO FORMA



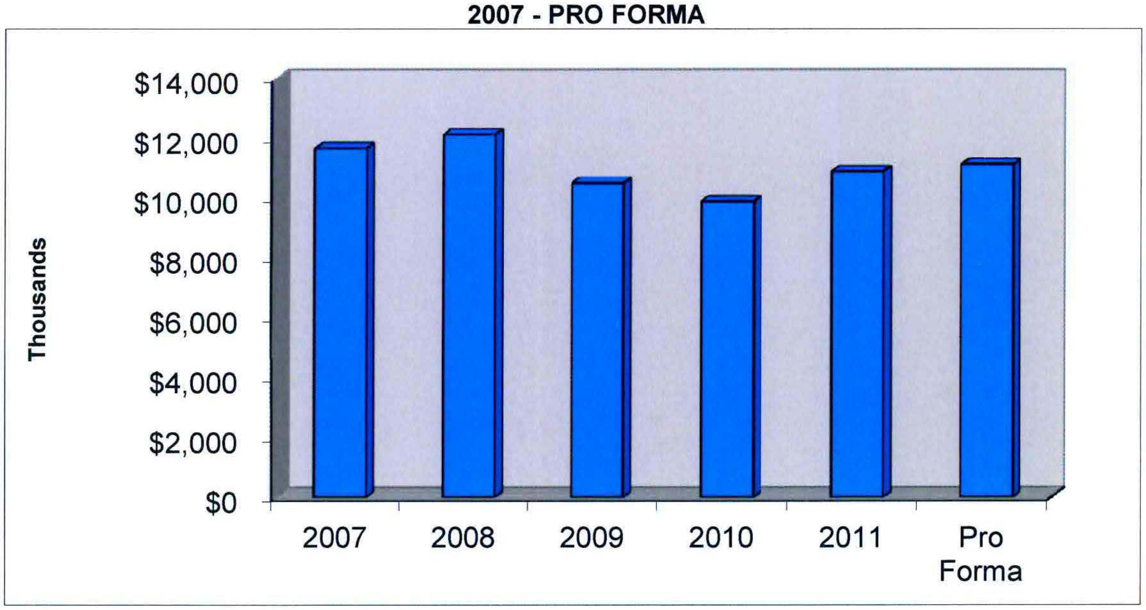
Administrative & General O&M					
2007	2008	2009	2010	2011	Pro Forma
$4,599,672	$4,620,544	$3,875,221	$3,410,276	$4,127,510	$4,182,103

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF TOTAL O&M
2007 - PRO FORMA



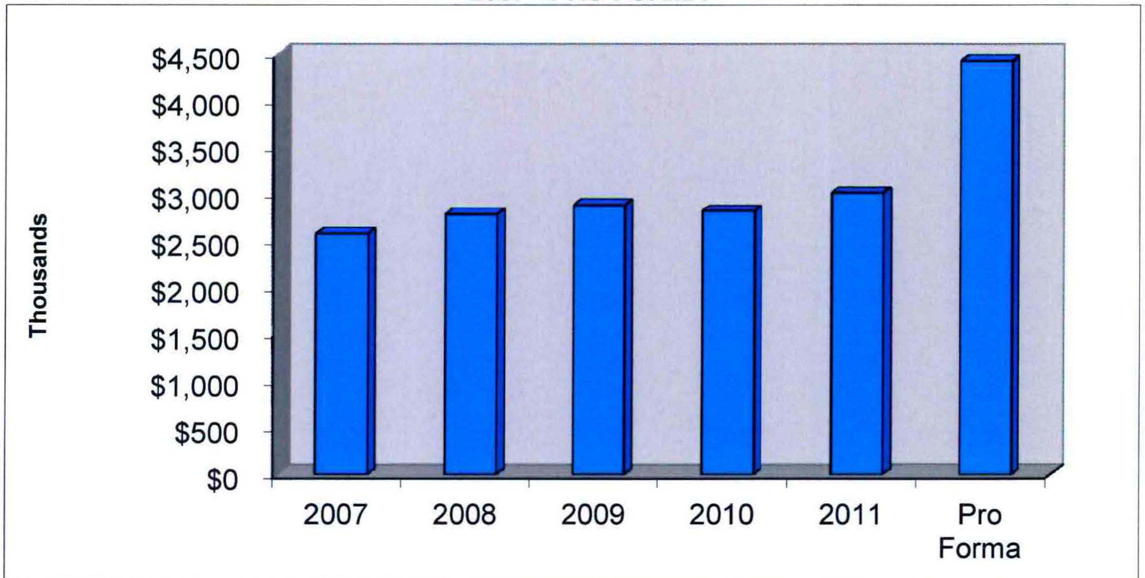
Total O&M					
2007	2008	2009	2010	2011	Pro Forma
$62,387,075	$86,553,860	$67,857,121	$61,015,639	$63,604,342	$49,971,650

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF O&M EXCLUDING COST OF GAS
2007 - PRO FORMA



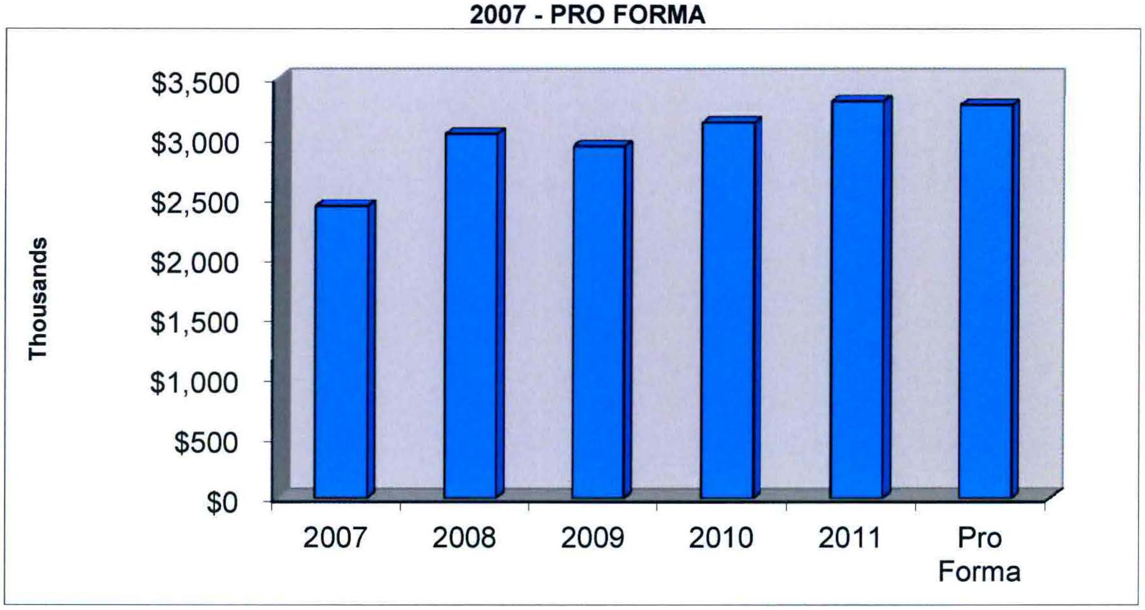
O&M Excluding Cost of Gas					
2007	2008	2009	2010	2011	Pro Forma
$11,658,376	$12,119,772	$10,502,083	$9,877,278	$10,869,311	$11,117,078

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION & AMORTIZATION EXPENSE
2007 - PRO FORMA



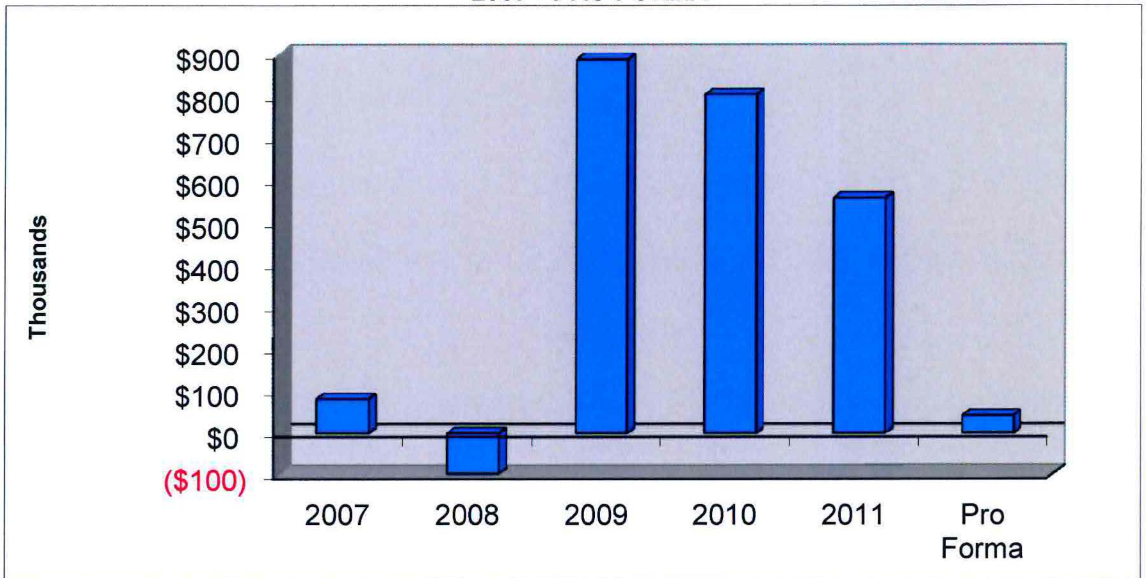
Depreciation & Amortization Expense					
2007	2008	2009	2010	2011	Pro Forma
$2,577,959	$2,781,508	$2,879,850	$2,815,887	$3,011,298	$4,423,602

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF TAXES OTHER THAN INCOME
2007 - PRO FORMA



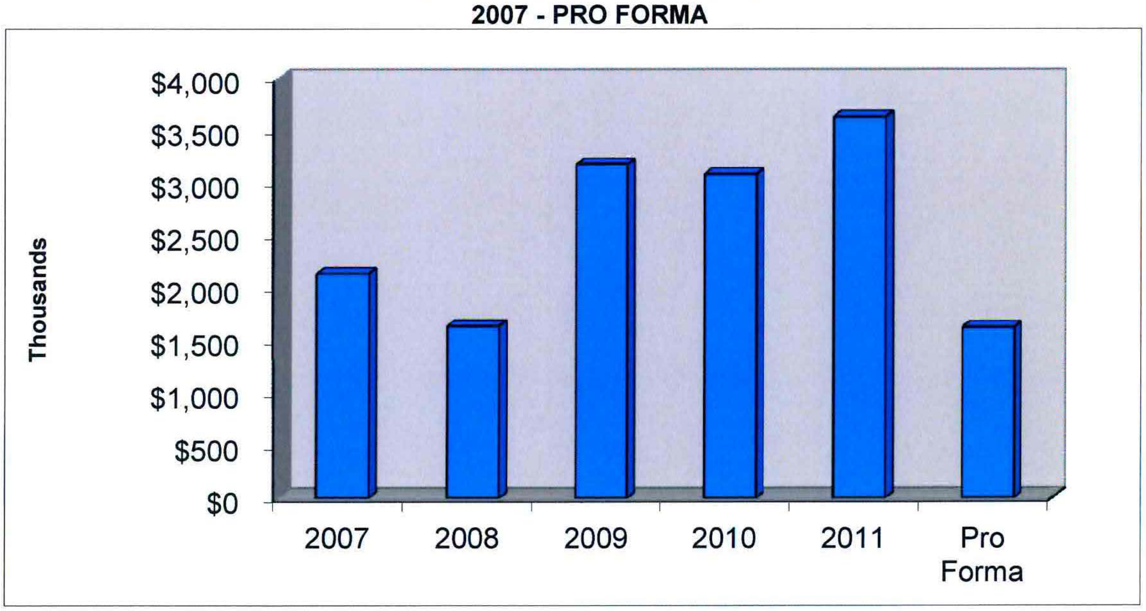
Taxes Other Than Income					
2007	2008	2009	2010	2011	Pro Forma
$2,433,268	$3,034,380	$2,928,948	$3,126,339	$3,308,019	$3,275,499

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF INCOME TAXES
2007 - PRO FORMA



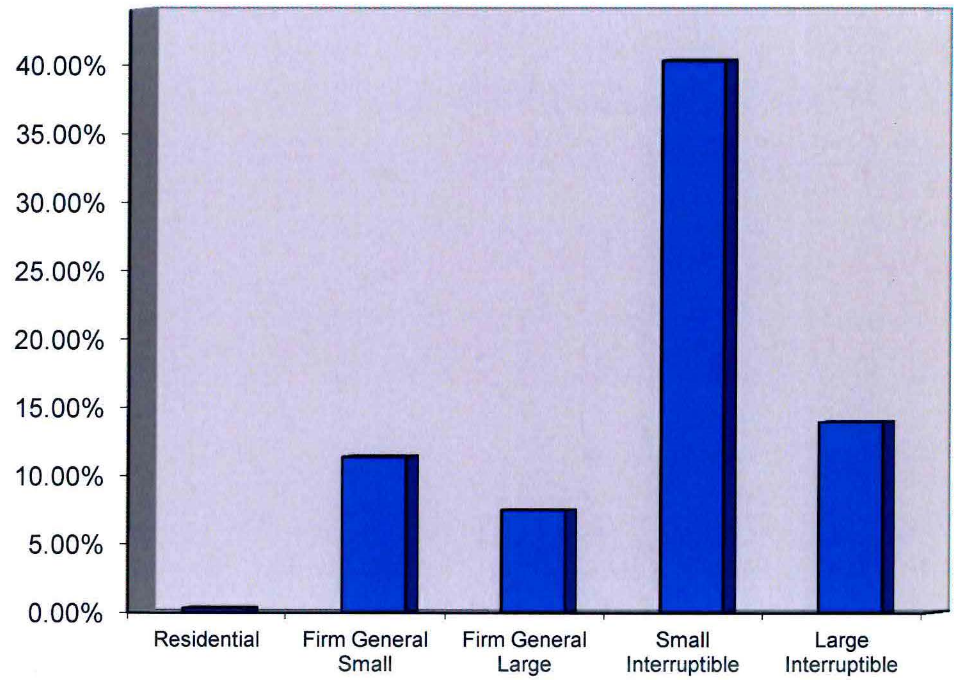
Income Taxes					
2007	2008	2009	2010	2011	Pro Forma
$82,424	($96,931)	$888,428	$804,658	$559,015	$41,351

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF NET INCOME
2007 - PRO FORMA



Net Income					
2007	2008	2009	2010	2011	Pro Forma
$2,136,765	$1,637,863	$3,176,154	$3,081,995	$3,628,300	$1,627,024

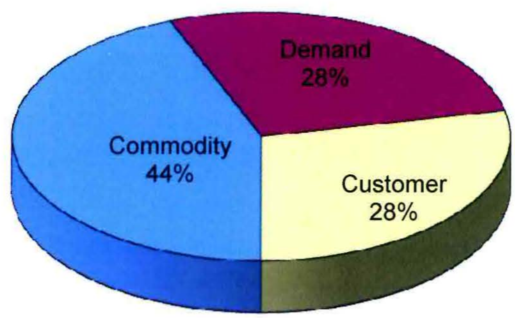
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE



Pro Forma Rate of Return			
Residential	0.278%	Small Interruptible	40.315%
Firm General Small	11.364%	Large Interruptible	13.934%
Firm General Large	7.444%		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
COST OF SERVICE BY COMPONENT

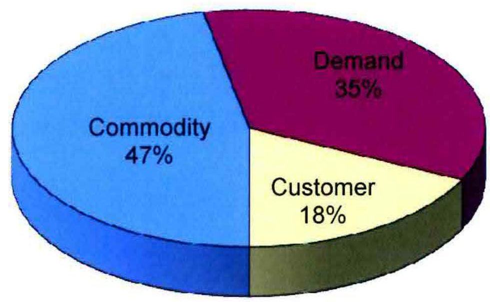
Class Cost of Service - Residential



Commodity	**$17,437,882**
Demand	**$10,972,868**
Customer	**$11,235,835**

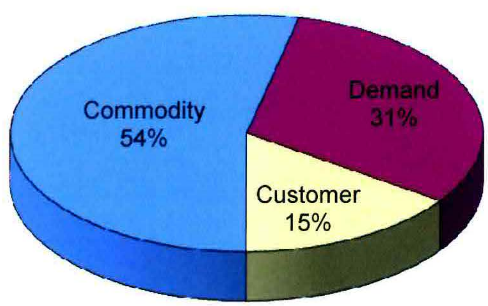
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
COST OF SERVICE BY COMPONENT

Class Cost of Service - Firm General-Small



Commodity	**$3,023,455**
Demand	**$2,279,243**
Customer	**$1,147,463**

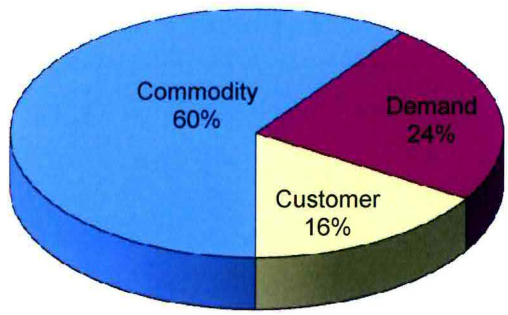
Class Cost of Service - Firm General-Large



Commodity	**$7,906,833**
Demand	**$4,605,944**
Customer	**$2,257,324**

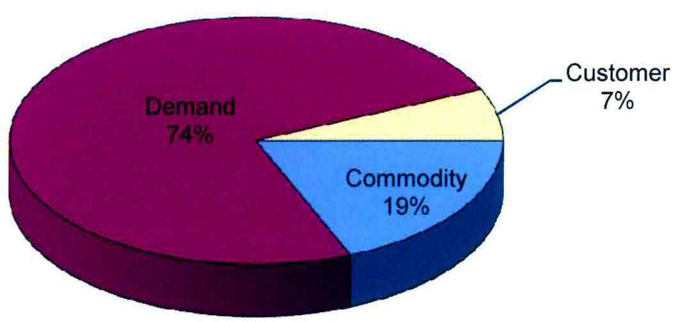
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
COST OF SERVICE BY COMPONENT

Class Cost of Service - Small Interruptible



Commodity	**$619,361**
Demand	**$246,066**
Customer	**$166,808**

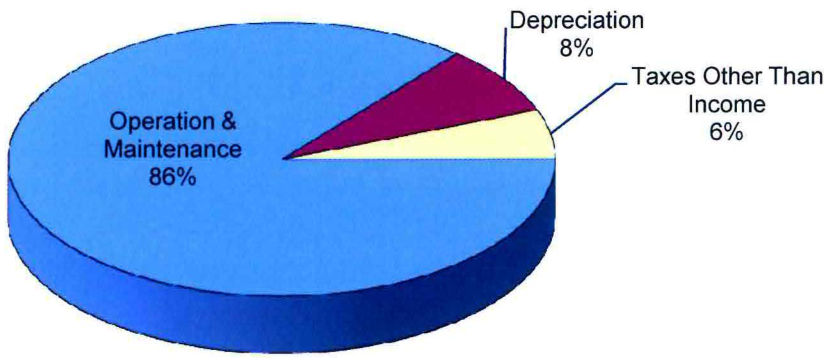
Class Cost of Service - Large Interruptible



Commodity	**$89,746**
Demand	**$357,154**
Customer	**$32,510**

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
PRO FORMA 2012

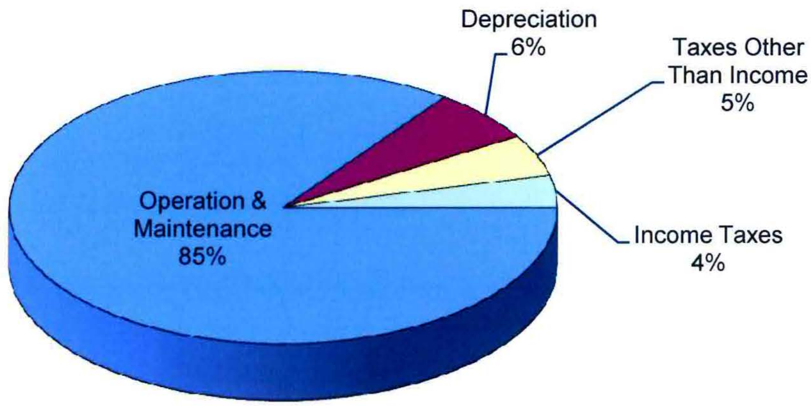
Residential Service



Operation & Maintenance	**$31,499,567**	**Taxes Other Than Income**	**$2,136,878**
Depreciation	**$2,984,926**	**Income Taxes**	**($691,208)**

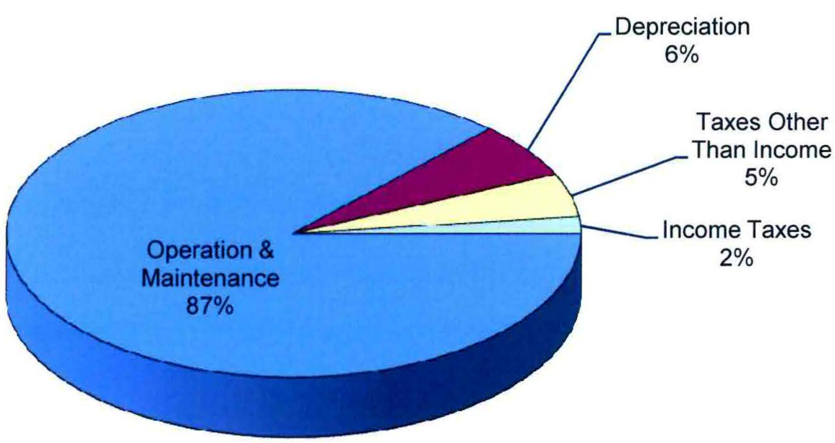
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
PRO FORMA 2012

Firm General Service-Small



Operation & Maintenance	**$5,282,082**	**Taxes Other Than Income**	**$305,168**
Depreciation	**$390,524**	**Income Taxes**	**$235,227**

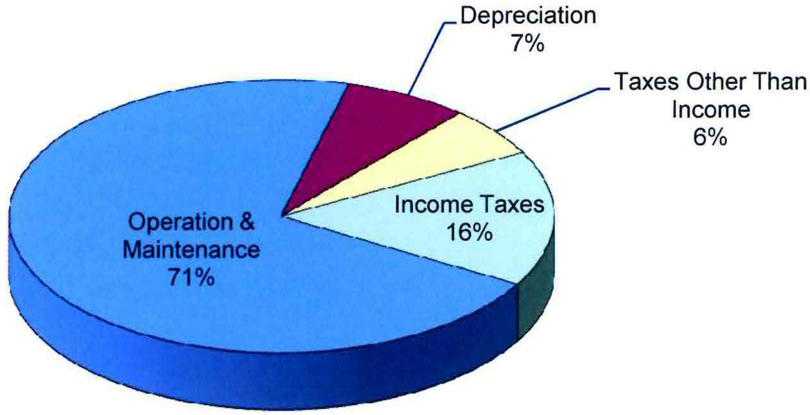
Firm General Service-Large



Operation & Maintenance	**$12,174,184**	**Taxes Other Than Income**	**$686,509**
Depreciation	**$877,852**	**Income Taxes**	**$257,054**

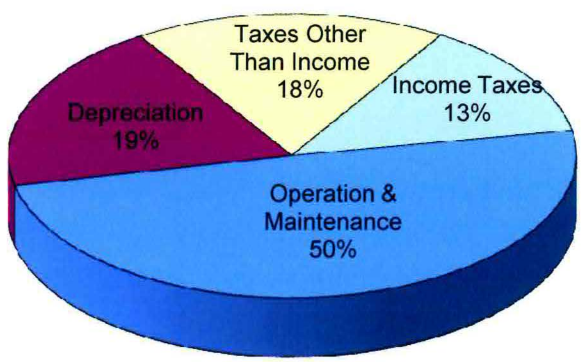
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED CLASS COST OF SERVICE
PRO FORMA 2012

Small Interruptible Service



Operation & Maintenance	**$793,498**	**Taxes Other Than Income**	**$66,748**
Depreciation	**$83,018**	**Income Taxes**	**$179,893**

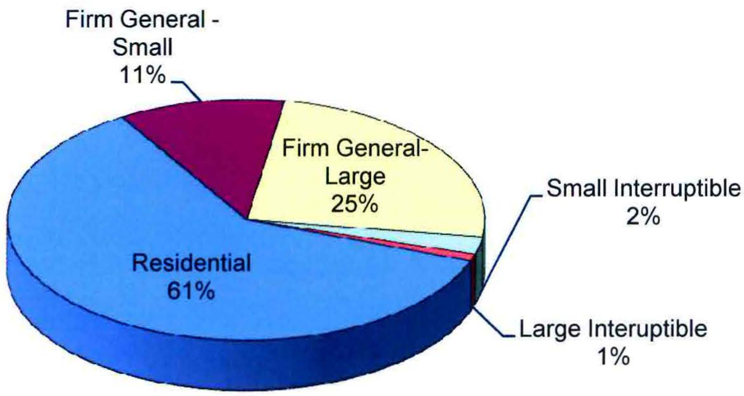
Large Interruptible Service



Operation & Maintenance	**$222,318**	**Taxes Other Than Income**	**$80,196**
Depreciation	**$87,282**	**Income Taxes**	**$60,386**

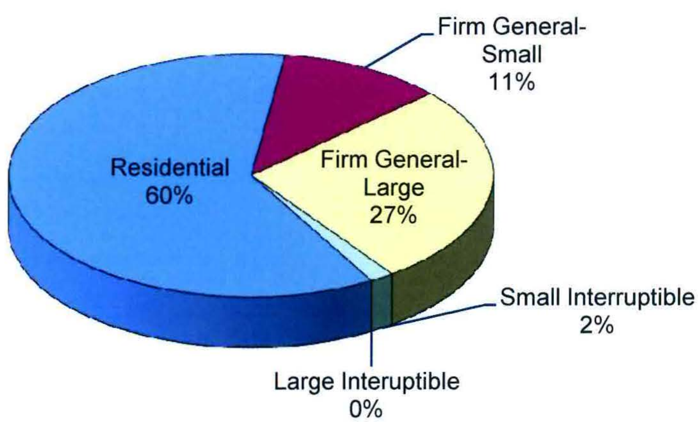
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED - PRO FORMA 2012
FUNCTIONALIZED COST BY CLASS

Revenue



Residential	**$36,010,398**	**Small Interruptible**	**$1,395,064**
Firm General-Small	**$6,685,699**	**Large Interruptible**	**$557,476**
Firm General-Large	**$14,690,489**		

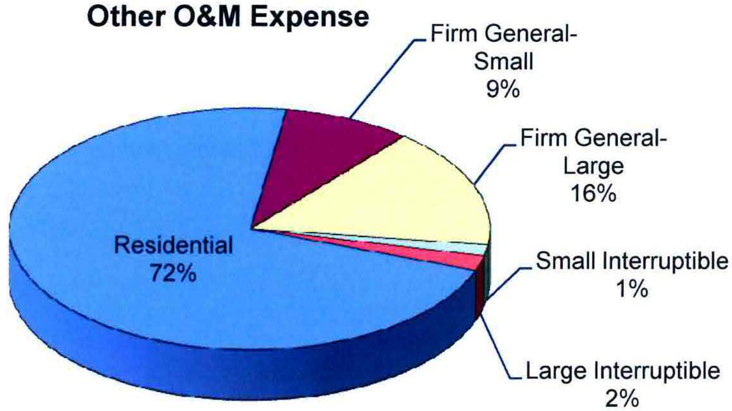
Cost of Purchased Gas



Residential	**$23,516,497**	**Small Interruptible**	**$629,029**
Firm General-Small	**$4,316,508**	**Large Interruptible**	**$0**
Firm General-Large	**$10,392,538**		

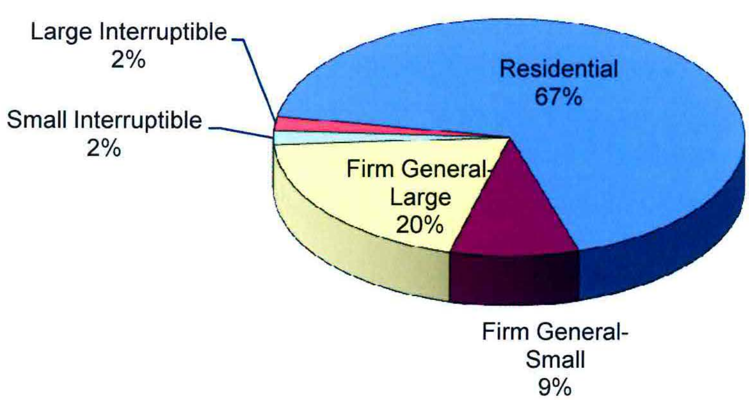
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED - PRO FORMA 2012
FUNCTIONALIZED COST BY CLASS

Other O&M Expense



Residential	**$7,983,070**	**Small Interruptible**	**$164,469**
Firm General-Small	**$965,574**	**Large Interruptible**	**$222,318**
Firm General-Large	**$1,781,646**		

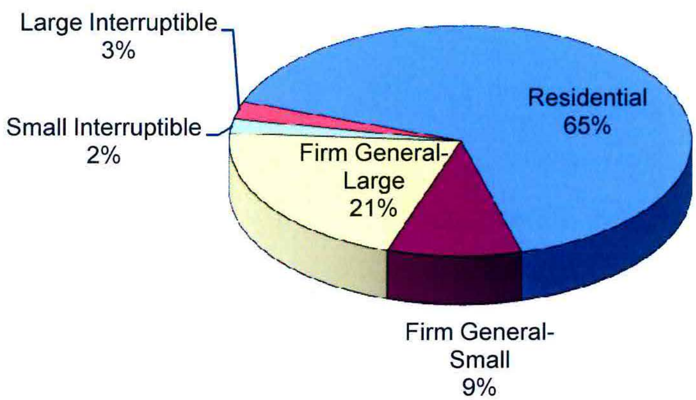
Depreciation Expense



Residential	**$2,984,926**	**Small Interruptible**	**$83,018**
Firm General-Small	**$390,524**	**Large Interruptible**	**$87,282**
Firm General-Large	**$877,852**		

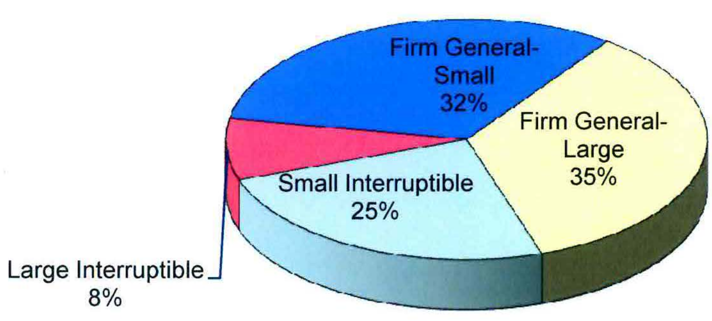
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED - PRO FORMA 2012
FUNCTIONALIZED COST BY CLASS

Taxes Other Than Income



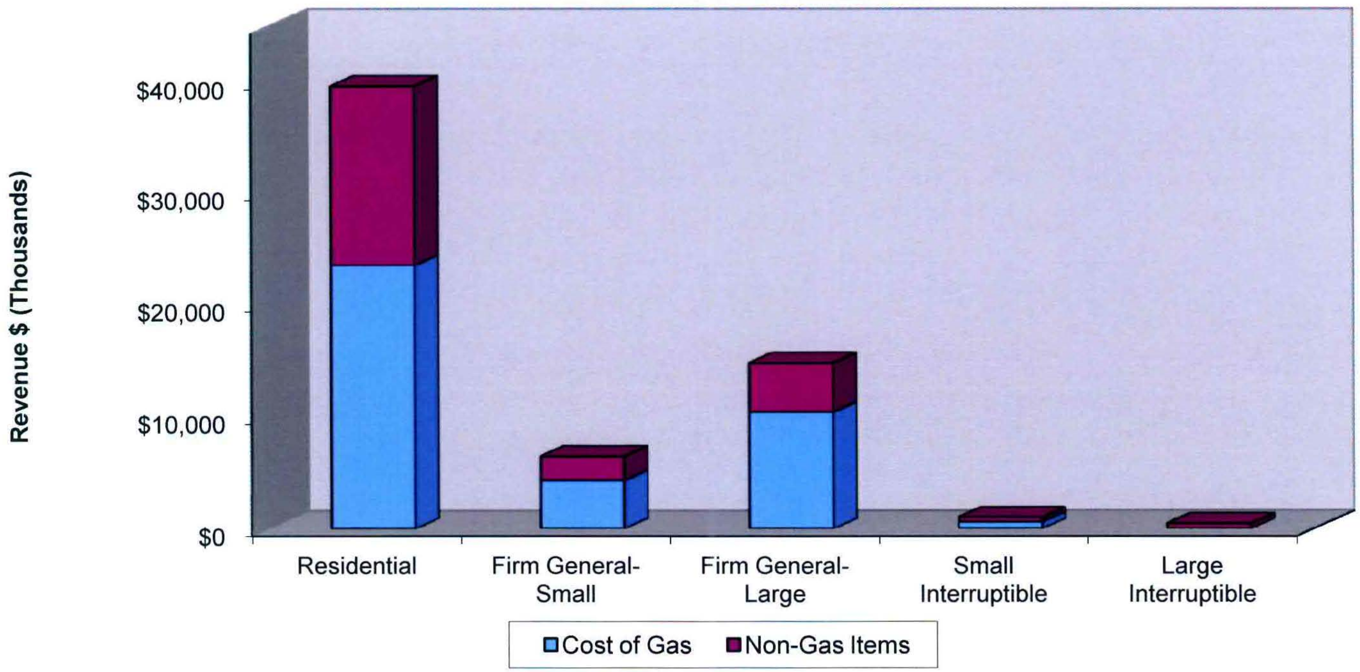
Residential	**$2,136,878**	**Small Interruptible**	**$66,748**
Firm General-Small	**$305,168**	**Large Interruptible**	**$80,196**
Firm General-Large	**$686,509**		

Income Taxes



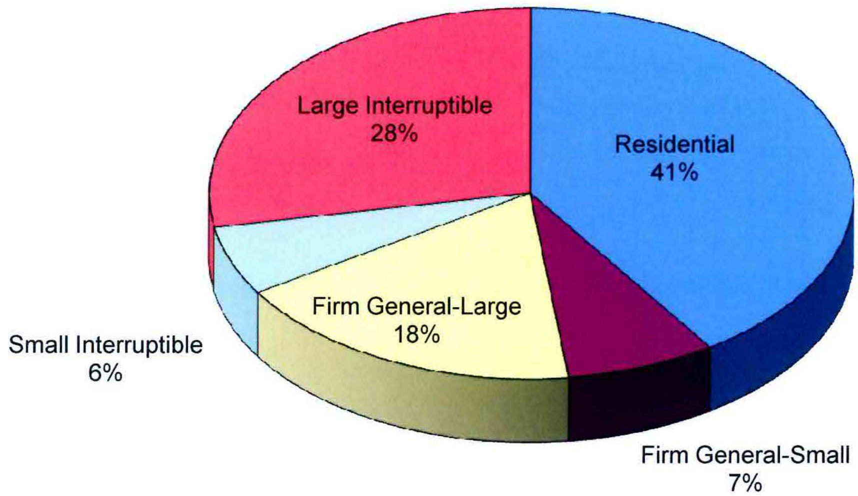
Residential	**($691,208)**	**Small Interruptible**	**$179,893**
Firm General-Small	**$235,227**	**Large Interruptible**	**$60,386**
Firm General-Large	**$257,054**		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
EMBEDDED - PRO FORMA 2012
FUNCTIONALIZED COST BY CLASS

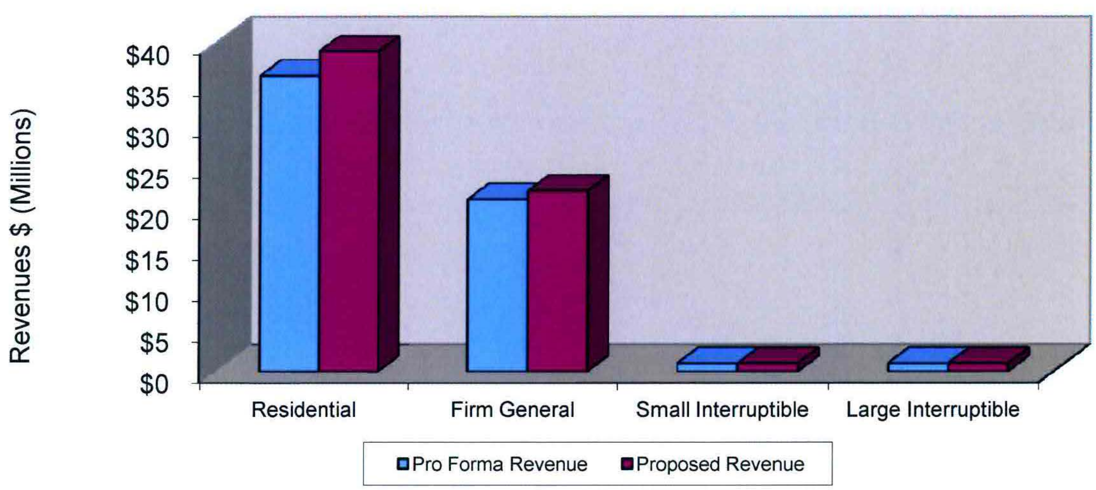


	Residential	Firm General Small	Firm General Large	Small Interruptible	Large Interruptible
Cost of Gas	$23,516,497	$4,316,508	$10,392,538	$629,029	$0
Non-Gas Items	$16,130,088	$2,133,653	$4,377,563	$403,206	$479,410

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA



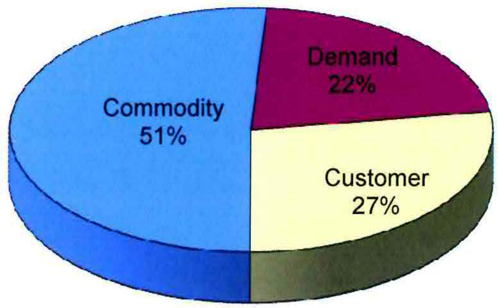
Pro Forma Billing Determinants Dk			
Residential	6,097,461	Small Interruptible	904,879
Firm General-Small	1,119,203	Large Interruptible	4,197,933
Firm General-Large	2,694,623		



Revenues Under Current & Proposed Rates				
	Residential	Firm General	Small Interruptible	Large Interruptible
Pro Forma Revenue	$35,729,916	$21,256,783	$1,387,511	$548,804
Proposed Revenue	$38,871,114	$21,546,103	$1,406,672	$556,304
Percent Increase	8.80%	1.40%	1.40%	1.40%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST OF SERVICE - RECONCILED TO EMBEDDED

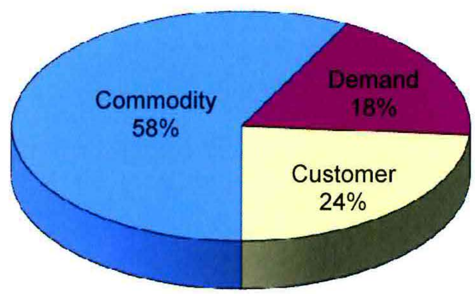
Class Cost of Service - Residential



Residential	
Commodity	$21,880,919
Demand	$9,236,473
Customer	$11,770,489

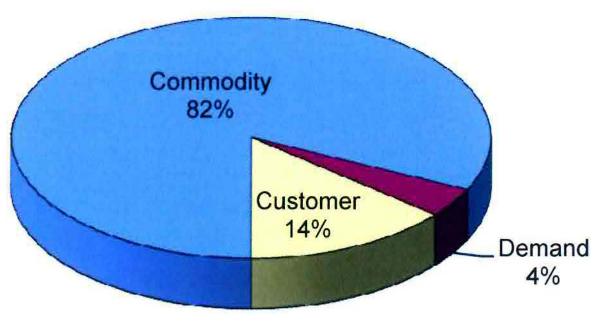
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST OF SERVICE - RECONCILED TO EMBEDDED

Class Cost of Service - Firm General-Small



Firm General	
Commodity	$4,020,902
Demand	$1,302,037
Customer	$1,655,182

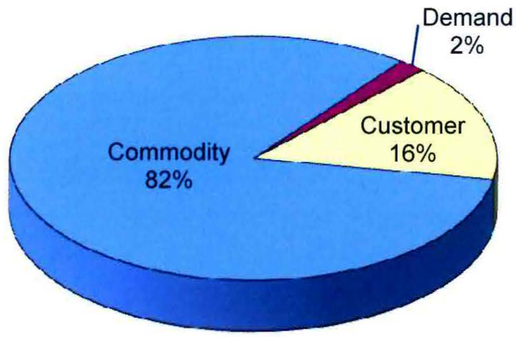
Class Cost of Service - Firm General-Large



Firm General	
Commodity	$9,665,808
Demand	$464,524
Customer	$1,644,359

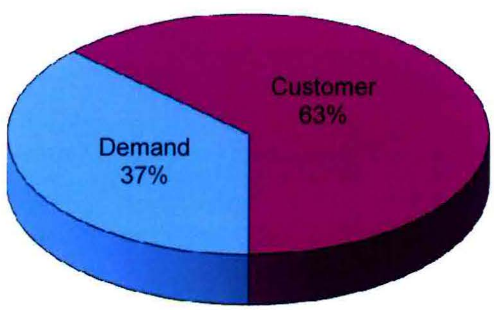
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST OF SERVICE - RECONCILED TO EMBEDDED

Class Cost of Service - Small Interruptible



Small Interruptible	
Commodity	$585,964
Demand	$12,910
Customer	$110,843

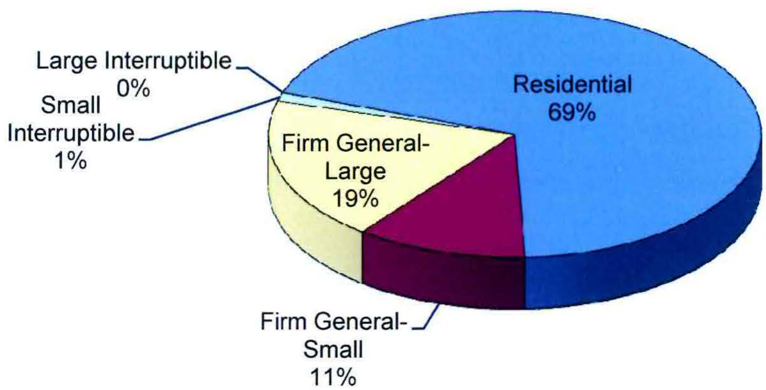
Class Cost of Service - Large Interruptible



Large Interruptible	
Commodity	$0
Demand	$10,386
Customer	$17,696

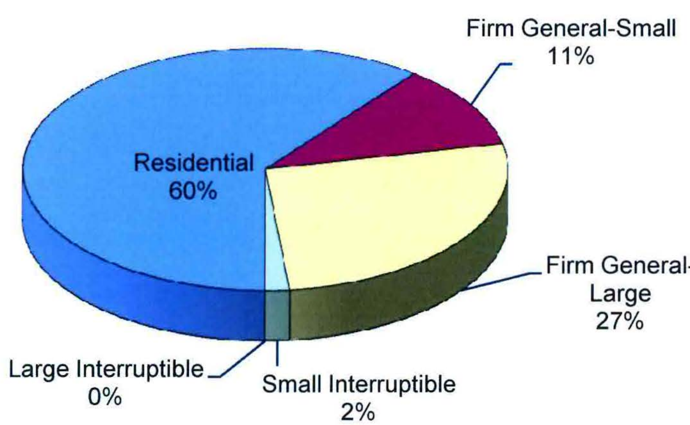
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST OF SERVICE - RECONCILED TO EMBEDDED

Total Marginal Cost by Class



Residential	**$42,887,881**	**Small Interruptible**	**$709,717**
Firm General-Small	**$6,978,121**	**Large Interruptible**	**$28,082**
Firm General-Large	**$11,774,691**		

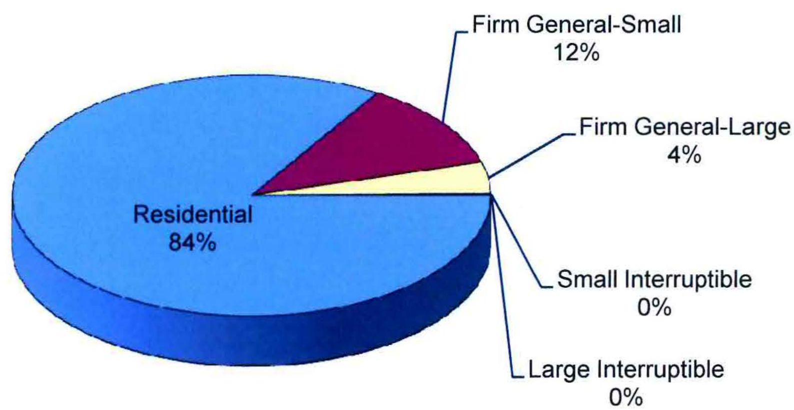
Functionalized Cost by Class - Commodity



Residential	**$21,880,919**	**Small Interruptible**	**$585,964**
Firm General-Small	**$4,020,902**	**Large Interruptible**	**$0**
Firm General-Large	**$9,665,808**		

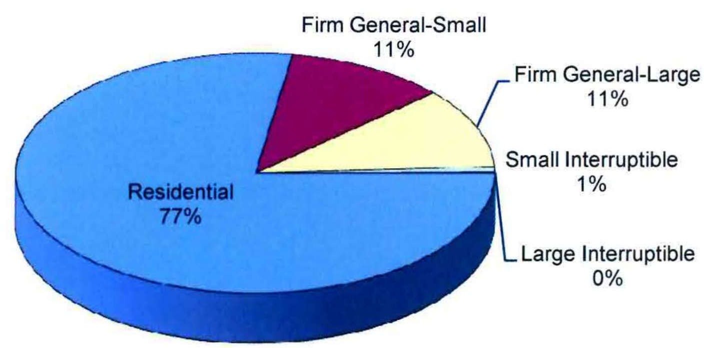
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST OF SERVICE - RECONCILED TO EMBEDDED

Functionalized Cost by Class - Demand



Residential	**$9,236,473**	**Small Interruptible**	**$12,910**
Firm General-Small	**$1,302,037**	**Large Interruptible**	**$10,386**
Firm General-Large	**$464,524**		

Functionalized Cost by Class - Customer



Residential	**$11,770,489**	**Small Interruptible**	**$110,843**
Firm General-Small	**$1,655,182**	**Large Interruptible**	**$17,696**
Firm General-Large	**$1,644,359**		

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Natural Gas Service	)))))	Docket No. D2012.9.__

* * * * * *

APPLICATION FOR INTERIM INCREASE
IN NATURAL GAS RATES

COMES NOW Montana-Dakota Utilities Co. (Montana-Dakota or Applicant), a Division of MDU Resources Group, Inc., and respectfully moves that the Montana Public Service Commission (Commission) authorize, on an interim basis, rate relief of $1,686,422, to be effective within 30 days.

I.

Applicant is entitled to interim rate relief as more fully set forth in the Application, Testimony and Exhibits, and Supporting Statements and Workpapers filed in this Docket.

II.

The following rate schedules set forth in Appendix A hereto are proposed on an interim basis to be effective within 30 days:

Appendix A - Proposed Interim Tariffs

Volume 6

10th Revised Sheet No. 11	Residential Gas Service Rate 60
10th Revised Sheet No. 21	Firm General Gas Service Rate 70
11th Revised Sheet No. 23	Optional Seasonal General Gas Service Rate 72

III.

The requested interim relief is computed pursuant to the requirements of the Administrative Rules of Montana (ARM) §38.5.501 through §38.5.506 and is in full compliance therewith.

IV.

The requested interim rate increase of $1,686,422 is calculated based upon the adjustments and methodologies contained in the Commission's previous Orders.

WHEREFORE, Applicant respectfully requests that the Montana Public Service Commission grant interim rate relief to Applicant in the amount of $1,686,422, by authorizing the schedule of charges attached hereto as Appendix A, to become effective within 30 days.

Dated this 26th day of September, 2012.

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

By: ______________________
David L. Goodin
President and Chief Executive Officer

Appendix A

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$6.35 per month
Distribution Delivery Charge:	$1.126 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Public Service Commission of Montana

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

Natural Gas Service

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

Issued: September 26, 2012 **By:** Tamie A. Aberle
Director - Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Tariffs Reflecting Proposed Changes

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	$6.35 per month
Distribution Delivery Charge:	$1.126 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Universal System Benefits Charge:

Bills are subject to the charge for the Universal System Benefits Program as set forth in Rate 89.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

FIRM GENERAL GAS SERVICE Rate 70

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in the Gas Cost Tracking Adjustment Procedure Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

OPTIONAL SEASONAL GENERAL GAS SERVICE
Rate 72

Availability:

In all communities served for all firm purposes except for resale. See Rate 100, §V.3, for definition of class of service.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$10.40 per month
For customers with meters rated over 500 cubic feet per hour	$22.05 per month
Distribution Delivery Charge:	$1.353 per dk
Cost of Gas:	
Winter- Service rendered October 1 through May 31	Determined Monthly- See Rate Summary Sheet for Current Rate
Summer- Service rendered June 1 through September 30	Determined Monthly- See Rate Summary Sheet for Current Rate
Interim Rate Increase:	8.99% of amount billed under Basic Service Charge and Distribution Delivery Charge

Minimum Bill:

Basic Service Charge.

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA INCOME STATEMENT - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

	Per Books	Pro Forma Adjustments	Total Adjusted Amount
Operating Revenues			
Sales	$72,489,259	($14,697,778)	$57,791,481
Transportation	1,252,889	(121,356)	1,131,533
Other	368,826	47,286	416,112
Total Revenues	74,110,974	(14,771,848)	59,339,126
Operating Expenses			
Operation and Maintenance			
Cost of Gas	52,735,031	(13,880,459)	38,854,572
Other O&M	10,869,311	136,431	11,005,742
Total O&M	63,604,342	(13,744,028)	49,860,314
Depreciation	3,011,298	9,134	3,020,432
Taxes Other Than Income	3,308,019	(133,351)	3,174,668
Current Income Taxes	(2,930,186)	1,396,303	(1,533,883)
Deferred Income Taxes	3,489,201	(1,264,391)	2,224,810
Total Expenses	70,482,674	(13,736,333)	56,746,341
Operating Income	$3,628,300	($1,035,515)	$2,592,785
Rate Base	$43,247,498	($704,186)	$42,543,312
Rate of Return	8.390%		6.094%

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PRO FORMA ADJUSTMENTS - INTERIM
GAS UTILITY - MONTANA

	Adjustment No.	Pro Forma Adjustment	Rule
Revenue			
Current rates	1	($13,609,329)	38.5.164 Statement H, page 3
Normal Weather	2	(1,467,031)	38.5.164 Statement H, page 4
Annualized volumes	3	257,226	38.5.164 Statement H, page 5
Other Revenue	4	47,286	38.5.164 Statement H, page 6
Total adjustments to Revenue		($14,771,848)	
Expenses			
Cost of Gas	5	($13,880,459)	38.5.157 Statement G, page 3
Other O&M			
Labor	6	269,722	38.5.157 Statement G, page 4
Benefits	7	(75,501)	38.5.157 Statement G, page 5
Vehicles & Work Equipment	8	(9,752)	38.5.157 Statement G, page 6
Company Consumption	9	(8,120)	38.5.157 Statement G, page 7
Uncollectible Accounts	10	(14,963)	38.5.157 Statement G, page 8
Advertising	11	(31,656)	38.5.157 Statement G, page 9
Insurance	12	13,839	38.5.157 Statement G, page 10
Industry Dues	13	(7,138)	38.5.157 Statement G, page 11
Total adjustments to Other O&M		136,431	
Depreciation Expense	14	9,134	38.5.165 Statement I, page 2
Taxes Other than Income			
Ad Valorem	15	13,556	38.5.174 Statement K, page 1
Payroll Taxes	16	20,322	38.5.174 Statement K, page 2
MCC and PSC Taxes	17	(167,229)	38.5.174 Statement K, page 3
Total adj. to Taxes Other than Income		(133,351)	
Current Income Taxes			
Interest Annualization	18	(85,734)	38.5.169 Statement J, page 2
Other Tax Deductions	19	(400,022)	38.5.169 Statement J, page 3
Income Taxes on Pro Forma Adj.	20	(164,579)	38.5.169 Statement J, page 4
Elimination of Closing/Filing	21	1,560,882	38.5.169 Statement J, page 5
Total adj. to Current Income Taxes		1,396,303	
Deferred Income Taxes			
Elimination of Closing/Filing and Prior Period	21	(1,302,970)	38.5.169 Statement J, page 5
Other Tax Deductions	19	38,579	38.5.169 Statement J, page 3
Total adj. to Deferred Income Taxes		(1,264,391)	
Total Expenses		(13,736,333)	
Net Adjustments to Operating Income		($1,035,515)	

MONTANA-DAKOTA UTILITIES CO.
AVERAGE RATE BASE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011
PRO FORMA

	Average Balance @ 12/31/11	Pro Forma Adjustments	Pro Forma
Gas Plant in Service	$94,105,839	$0	$94,105,839
Accumulated Reserve for Depreciation	51,259,183	0	51,259,183
Net Gas Plant in Service	42,846,656	0	42,846,656
CWIP in Service Pending Reclassificatior	500,474		500,474
Total Gas Plant in Service	43,347,130	0	43,347,130
Additions			
Materials and Supplies	533,337	99,695	633,032
Gas in Underground Storage	7,134,766	(855,502)	6,279,264
Prepayments	1,175,889	(549,107)	626,782
Unamortized Gain (Loss) on Debt	584,820		584,820
Provision for Pensions & Benefits		1,268,837	1,268,837
Provision for Injuries & Damages		(109,736)	(109,736)
Deferred FAS 106 Costs	128,892	273,775	402,667
Total Additions	9,557,704	127,962	9,685,666
Total Before Deductions	$52,904,834	$127,962	$53,032,796
Deductions			
Accumulated Deferred Income Taxes	8,925,996	857,158	9,783,154
Accumulated Investment Tax Credits	4,084	(4,084)	0
Customer Advances	727,256	(20,926)	706,330
Total Deductions	9,657,336	832,148	10,489,484
Total Rate Base	$43,247,498	($704,186)	$42,543,312

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
SUMMARY OF PRO FORMA RATE BASE ADJUSTMENTS
INTERIM

	Adjustment	Amount	Rule
Additions:			
Materials and Supplies	A	99,695	38.5.143 Statement E, page 1
Gas in Underground Storage	B	(855,502)	38.5.143 Statement E, page 2
Prepaid Insurance	C	93,808	38.5.143 Statement E, page 3
Prepaid Demand and Commodity	D	(642,915)	38.5.143 Statement E, page 4
Provision for Pensions & Benefits	E	1,268,837	38.5.143 Statement E, page 6
Provision for Injuries & Damages	F	(109,736)	38.5.143 Statement E, page 7
Deferred FAS 106 Costs	G	273,775	38.5.143 Statement E, page 8
Total Additions		127,962	
Deductions:			
Accumulated Def. Inc. Tax			
Normalization	I	(53,293)	38.5.169 Statement J, page 7
Pensions & Benefits	E	846,179	38.5.143 Statement E, page 6
Injuries and Damages	F	(41,583)	38.5.143 Statement E, page 7
Deferred FAS 106 Costs	G	105,855	38.5.143 Statement E, page 8
Investment Tax Credits	J	(4,084)	38.5.169 Statement J, page 8
Customer Advances for Construction	H	(20,926)	38.5.143 Statement E, page 9
Total Deductions		832,148	
Total Pro Forma Adjustments		($704,186)	

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN - INTERIM
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$57,791,481	**$1,686,101**	$59,477,582
Transportation	1,131,533		1,131,533
Other	416,112		416,112
Total Revenues	59,339,126	1,686,101	61,025,227
Operating Expenses			
Operation and Maintenance			
Cost of Gas	38,854,572		38,854,572
Other O&M	11,005,742		11,005,742
Total O&M	49,860,314		49,860,314
Depreciation	3,020,432		3,020,432
Taxes Other Than Income	3,174,668	5,396 2/	3,180,064
Current Income Taxes	(1,533,883)	661,988 2/	(871,895)
Deferred Income Taxes	2,224,810		2,224,810
Total Expenses	56,746,341	667,384	57,413,725
Operating Income	$2,592,785	$1,018,717	$3,611,502
Rate Base	$42,543,312		$42,543,312
Rate of Return	**6.094%**		**8.489%**

1/ See Rule 38.5.175, page 1.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of .12% and PSC tax of .20%.

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MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND
DECEMBER 31, 2011

	2010	2011
Assets and Other Debits		
Utility Plant	$1,343,386,275	$1,393,817,730
Construction Work in Progress	40,572,541	54,926,027
Less Acc. Provision for Depreciation and Amortization	673,742,452	699,092,675
Net Utility Plant	710,216,364	749,651,082
Gas Stored Underground - Noncurrent	3,560,347	3,551,913
Other Property and Investments		
Nonutility Property	4,168,474	4,345,368
(Less) Accum. Prov. for Depr. And Amort.	1,311,967	1,460,122
Investment in Subsidiary Companies	2,336,133,125	2,402,890,906
Other investments	48,037,819	47,834,766
Net Other Property and Investments	2,387,027,451	2,453,610,918
Current and Accrued Assets		
Cash	6,238,148	6,845,910
Special Deposits	1,200	1,200
Working Fund	36,865	54,764
Temporary Cash Investments	0	0
Customer Accounts Receivable	29,395,116	26,202,128
Other Accounts Receivable	4,363,648	2,785,945
(Less) Accum.Prov. For Uncollectible Acct. - Credit	231,003	237,599
Notes Receivable from Assoc. Companies	0	0
Accounts Receivable from Assoc.Companies	27,836,855	28,733,840
Fuel Stock	5,029,867	5,921,977
Plant Materials and Operating Supplies	10,139,125	14,611,115
Merchandise	876,220	915,028
Stores Expense Undistributed	(639)	0
Gas Stored Underground - Current	18,538,439	21,147,886
Prepayments	4,438,120	4,929,924
Accured Utility Revenues	37,326,027	31,824,896
Miscellaneous Current and Accrued Assets	0	0
Total Current and Accrued Assets	143,987,988	143,737,014
Deferred Debits		
Unamortized Debt Expenses	1,126,622	1,046,963
Unrecovered Plant and Regulatory Study Costs	7,564,400	8,953,457
Other Regulatory Assets	86,467,267	123,145,685
Prelim. Survey and Investigation Charges (Electric)	321,479	1,311,495
Prelim. Survey and Investigation Charges (Natural Gas)	0	0
Clearing Accounts	109,955	141,904
Miscellaneous Deferred Debits	25,010,265	28,845,868
Unamortized Loss on Reaquired Debt	9,565,612	8,846,102
Accumulated Deferred Income Taxes	59,053,683	65,712,445
Unrecovered Purchased Gas Costs	2,110,509	2,622,263
Total Deferred Debits	191,329,792	240,626,182
Total Assets and Other Debits	$3,436,121,942	$3,591,177,109

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND
DECEMBER 31, 2011

	2010	2011
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$188,901,379	$189,332,485
Preferred Stock Issued	15,000,000	15,000,000
Premium on Capital Stock	1,030,458,868	1,039,849,252
(Less) Capital Stock Expense	4,110,305	4,110,305
Retained Earnings	492,507,658	505,281,931
Unappropriated Undistributed Sub Earnings	1,004,931,088	1,080,840,155
(Less) Reacquired Capital Stock	3,625,813	3,625,813
Accumulated Other Comprehensive Income	(31,261,155)	(47,000,996)
Total Proprietary Capital	2,692,801,720	2,775,566,709
Long-Term Debt		
Bonds	280,000,000	280,000,000
Other Long-Term Debt	995,927	888,853
(Less) Unamortized Discount on Long-Term Debt-Debit	0	0
Total Long-Term Debt	280,995,927	280,888,853
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	936,497	568,573
Accumulated Provision for Pensions and Benefits	54,957,735	73,404,001
Accumulated Provision for Rate Refunds	0	640,000
Asset Retirement Obligations	6,314,471	6,645,275
Total Other Noncurrent Liabilities	62,208,703	81,257,849
Current and Accrued Liabilities		
Notes Payable	20,000,000	0
Accounts Payable	34,271,793	36,325,957
Accounts Payable to Associated Companies	9,445,305	4,867,683
Customer Deposits	2,019,003	1,926,012
Taxes Accrued	5,133,221	18,303,603
Interest Accrued	4,928,786	4,928,205
Dividends Declared	30,772,550	31,794,172
Tax Collections Payable	1,963,158	1,660,047
Miscellaneous Current and Accrued Liabilities	23,267,497	21,988,799
Total Current and Accrued Assets	131,801,313	121,794,478
Deferred Credits		
Customer Advances for Construction	7,133,209	8,440,494
Accumulated Deferred Investment Tax Credit	797,879	871,217
Other Deferred Credits	88,934,756	108,892,007
Other Regulatory Liabilities	8,088,640	10,003,775
Accumulated Deferred Income Taxes	163,359,795	203,461,727
Total Deferred Credits	268,314,279	331,669,220
Total Liabilities and Equity	$3,436,121,942	$3,591,177,109

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2011 AND
JUNE 30, 2012

	2011	2012
Assets and Other Debits		
Utility Plant	$1,356,122,197	$1,412,357,266
Construction Work in Progress	46,776,499	100,110,499
Less Acc. Provision for Depreciation and Amortization	688,313,316	713,894,307
Net Utility Plant	714,585,380	798,573,458
Gas Stored Underground - Noncurrent	2,765,041	3,551,913
Other Property and Investments		
Nonutility Property	4,212,161	4,468,867
(Less) Accum. Prov. for Depr. And Amort.	1,377,001	1,548,142
Investment in Subsidiary Companies	2,357,546,703	2,442,402,802
Other investments	49,466,444	49,775,303
Net Other Property and Investments	2,409,848,307	2,495,098,830
Current and Accrued Assets		
Cash	40,181,141	3,243,811
Special Deposits	1,200	251,415
Working Fund	35,975	50,975
Temporary Cash Investments	0	0
Customer Accounts Receivable	25,871,417	17,000,792
Other Accounts Receivable	2,498,821	1,832,911
(Less) Accum.Prov. For Uncollectible Acct. - Credit	346,710	221,530
Notes Receivable from Assoc. Companies	0	0
Accounts Receivable from Assoc.Companies	27,280,773	27,846,311
Fuel Stock	3,908,960	5,109,064
Plant Materials and Operating Supplies	11,547,963	19,871,046
Merchandise	873,215	905,451
Stores Expense Undistributed	36,506	58,175
Gas Stored Underground - Current	2,480,991	13,102,007
Prepayments	2,390,075	3,105,790
Accured Utility Revenues	10,496,186	12,641,005
Miscellaneous Current and Accrued Assets	0	2,495,484
Total Current and Accrued Assets	127,256,513	107,292,707
Deferred Debits		
Unamortized Debt Expenses	1,098,609	1,000,051
Unrecovered Plant and Regulatory Study Costs	10,659,285	7,393,069
Other Regulatory Assets	80,603,619	119,405,158
Prelim. Survey and Investigation Charges (Electric)	645,080	472,602
Prelim. Survey and Investigation Charges (Natural Gas)	0	0
Clearing Accounts	1,354,878	883,754
Miscellaneous Deferred Debits	25,140,198	28,571,397
Unamortized Loss on Reaquired Debt	9,205,857	8,486,346
Accumulated Deferred Income Taxes	57,414,356	65,093,706
Unrecovered Purchased Gas Costs	598,173	(2,732,787)
Total Deferred Debits	186,720,055	228,573,296
Total Assets and Other Debits	$3,441,175,296	$3,633,090,204

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED BALANCE SHEET
JUNE 30, 2011 AND
JUNE 30, 2012

	2011	2012
Liabilities and Other Credits		
Proprietary Capital		
Common Stock Issued	$189,332,485	$189,369,450
Preferred Stock Issued	15,000,000	15,000,000
Premium on Capital Stock	1,037,476,242	1,041,044,905
(Less) Capital Stock Expense	4,110,305	4,110,305
Retained Earnings	500,449,310	510,047,453
Unappropriated Undistributed Sub Earnings	1,023,095,832	1,102,120,464
(Less) Reacquired Capital Stock	3,625,813	3,625,813
Accumulated Other Comprehensive Income	(32,267,799)	(29,574,553)
Total Proprietary Capital	2,725,349,952	2,820,271,601
Long-Term Debt		
Bonds	280,000,000	280,000,000
Other Long-Term Debt	992,403	7,885,162
(Less) Unamortized Discount on Long-Term Debt-Debit	0	0
Total Long-Term Debt	280,992,403	287,885,162
Other Noncurrent Liabilities		
Accumulated Provision for Injuries and Damages	747,153	526,179
Accumulated Provision for Pensions and Benefits	55,420,379	74,591,673
Accumulated Provision for Rate Refunds	0	1,280,682
Asset Retirement Obligations	6,476,302	6,626,786
Total Other Noncurrent Liabilities	62,643,834	83,025,320
Current and Accrued Liabilities		
Notes Payable	0	0
Accounts Payable	22,888,737	26,285,558
Accounts Payable to Associated Companies	6,332,840	6,508,399
Customer Deposits	1,923,378	1,920,511
Taxes Accrued	1,448,797	14,502,978
Interest Accrued	4,959,146	4,951,588
Dividends Declared	30,850,204	31,800,364
Tax Collections Payable	935,297	1,108,838
Miscellaneous Current and Accrued Liabilities	23,368,491	20,853,771
Total Current and Accrued Assets	92,706,890	107,932,007
Deferred Credits		
Customer Advances for Construction	6,908,677	10,163,593
Accumulated Deferred Investment Tax Credit	763,013	843,563
Other Deferred Credits	82,868,858	101,008,872
Other Regulatory Liabilities	10,883,825	10,173,075
Accumulated Deferred Income Taxes	178,057,844	211,787,011
Total Deferred Credits	279,482,217	333,976,114
Total Liabilities and Equity	$3,441,175,296	$3,633,090,204

NOTES TO THE FINANCIAL STATEMENTS

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $1.2 billion; current and accrued assets would increase by $1.1 billion; deferred debits would increase by $726.4 million; long-term debt would increase by $1.0 billion; other noncurrent liabilities and current and accrued liabilities would increase by $695.7 million; deferred credits would increase by $1.3 billion as of December 31, 2011. Furthermore, operating revenues would increase by $3.5 billion and operating expenses, excluding income taxes, would increase by $3.2 billion for the twelve months ended December 31, 2011. In addition, net cash provided by operating activities would increase by $407.3 million; net cash used in investing activities would increase by $384.1 million; net cash used in financing activities would increase by $82.8 million; the effect of exchange rate changes on cash would decrease by $214,000; and the net change in cash and cash equivalents would be a decrease of $59.9 million for the twelve months ended December 31, 2011. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Company's notes to the financial statements are presented consolidated with its subsidiary investments and prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2011	2010
	(In thousands)	
Aggregates held for resale	$ **78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182
Other	**32,998**	25,706
Total	$ **274,205**	$ 252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments
The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance investment contract, auction rate securities, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair

value option for its auction rate securities, mortgage-backed securities and U.S. Treasury securities. For more information, see Notes 8 and 16.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Property, plant and equipment at December 31 was as follows:

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 546,783	$ 538,071	47
Distribution	255,232	243,205	36
Transmission	179,580	161,972	44
Other	86,929	83,786	13
Natural gas distribution:			
Distribution	1,257,360	1,223,239	38
Other	311,506	285,606	23
Pipeline and energy services:			
Transmission	386,227	357,395	52
Gathering	42,378	41,931	19
Storage	41,908	33,967	51
Other	36,179	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	198,864	203,064	17
Other	13,735	13,512	10
Exploration and production:			
Natural gas and oil properties	2,577,576	2,320,967	*
Other	37,570	35,971	9
Construction materials and contracting:			
Land	126,790	124,018	—
Buildings and improvements	67,627	65,003	20
Machinery, vehicles and equipment	902,136	899,365	12
Construction in progress	8,085	4,879	—
Aggregate reserves	395,214	393,110	**
Construction services:			
Land	4,706	4,526	—
Buildings and improvements	15,001	14,101	22
Machinery, vehicles and equipment	95,891	94,252	7
Other	9,198	10,061	4
Other:			
Land	2,837	2,837	—
Other	46,910	29,727	24
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	
Net property, plant and equipment	$ 4,285,014	$ 4,115,180	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.*

** *Depleted on the units-of-production method.*

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 5.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

Due to low natural gas and oil prices that existed at March 31, 2009, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the year ended December 31, 2009.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of $107.9 million ($66.9 million after tax) at March 31, 2009, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

At December 31, 2011, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2011, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
			(In thousands)		
Acquisition	$ 185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$ 232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, respectively.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's swap and collar agreements are reflected at fair value. For more information, see Note 8.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax positions in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009*
	(In thousands)		
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

* *Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.*

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the acquisition method of accounting; natural gas and oil reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	**2011**	2010	2009
	(In thousands)		
Interest, net of amount capitalized	$ **78,133**	$ 80,962	$ 81,267
Income taxes paid (refunded), net	$ **(12,287)**	$ 46,892	$ 39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards

Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive loss resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
	(In thousands)		
Other comprehensive loss:			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	$ 7,900	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	—	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	7,900	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	(22,427)	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	(1,295)	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	82	—	—
Total other comprehensive loss	$ (15,740)	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Note 2 - Acquisitions

In 2011, a purchase price adjustment, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

In 2009, the Company acquired a pipeline and energy services business in Montana which was not material. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company's common stock and cash, was $22.0 million.

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 - Discontinued Operations
In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 - Equity Method Investments
Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2011 and 2010, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of December 31, 2011*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

** *Includes a purchase price adjustment that was not material related to an acquisition in a prior period.*

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010*	Goodwill Acquired During the Year**	Balance as of December 31, 2010*
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

* *Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.*

** *Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

Other amortizable intangible assets at December 31 were as follows:

		2011		2010
		(In thousands)		
Customer relationships	$	**21,702**	$	24,942
Accumulated amortization		**(10,392)**		(11,625)
		11,310		13,317
Noncompete agreements		**7,685**		9,405
Accumulated amortization		**(5,371)**		(6,425)
		2,314		2,980
Other		**11,442**		13,217
Accumulated amortization		**(4,223)**		(4,243)
		7,219		8,974
Total	**$**	**20,843**	$	25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Note 6 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period*	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	171,492	103,818
Deferred income taxes	**	119,189	114,427
Taxes recoverable from customers (a)	—	12,433	11,961
Plant costs (a)	Over plant lives	10,256	9,964
Long-term debt refinancing costs (a)	Up to 27 years	10,112	11,101
Costs related to identifying generation development (a)	Up to 15 years	9,817	13,777
Natural gas supply derivatives (b)	Up to 1 year	437	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	2,622	6,609
Other (a) (b)	Largely within 1 year	22,651	35,225
Total regulatory assets		359,009	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		289,972	276,652
Deferred income taxes**		84,963	64,017
Natural gas costs refundable through rate adjustments (d)		45,064	36,996
Taxes refundable to customers (c)		31,837	19,352
Other (c) (d)		8,393	16,080
Total regulatory liabilities		460,229	413,097
Net regulatory position		(101,220)	(96,856)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*

** *Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.*

(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.

(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.

(c) Included in other liabilities on the Consolidated Balance Sheets.

(d) Included in other accrued liabilities on the Consolidated Balance Sheets.

(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain

At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000.

The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $437,000.

Fidelity

At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $18.4 million.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 27,687	$ 15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$ 30,455	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 12,727	$ 15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$ 18,863	$ 30,911

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8

million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Signficant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* *The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541
Auction rate securities	—	11,400	—	11,400
Commodity derivative instruments - current	—	15,123	—	15,123
Commodity derivative instruments - noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$ —	$ 236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments - current	$ —	$ 24,428	$ —	$ 24,428
Commodity derivative instruments - noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$ —	$ 30,911	$ —	$ 30,911

* *The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only, and was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2011. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2011	Amount Outstanding at December 31, 2010	Letters of Credit at December 31, 2011	Expiration Date
			(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 100.0	$ — (h)	$ 20.0 (b)	$ —	5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ —	$ —	$ 1.9 (d)	12/28/12(e)
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (f)	$ 8.1	$ 20.2	$ —	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$ 400.0	$ — (h)	$ — (h)	$ 21.6 (d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program that was classified as short-term borrowings because the revolving credit agreement expired within one year.

(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.

(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

(e) Provisions allow for an extension of up to two years upon consent of the banks.

(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.

(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.

(h) Amount outstanding under commercial paper program.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Cascade Natural Gas Corporation Any borrowings under the $50 million revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Long-term debt

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

Intermountain Gas Company The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in 2010; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent. The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	**$ 1,287,576**	$ 1,358,848
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	**81,000**	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	**$ 1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

	2011	2010
	(In thousands)	
Balance at beginning of year	$ 95,970	$ 76,359
Liabilities incurred	3,870	8,608
Liabilities acquired	—	5,272
Liabilities settled	(10,418)	(10,740)
Accretion expense	4,466	3,588
Revisions in estimates	3,921	12,621
Other	342	262
Balance at end of year	$ 98,151	$ 95,970

The Company believes that any expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2011	2010
	(Dollars in thousands)	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	$ 10,000	$ 10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$ 15,000	$ 15,000

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 12 - Common Stock

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$ 13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$ 13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

	2011	2010	2009
Grant-date fair value	**$ 19.99**	$ 17.40	$ 20.39
Blended volatility range	**23.20% - 32.18%**	25.69% - 35.36%	40.40% - 50.98%
Risk-free interest rate range	**.09% - 1.34%**	.13% - 1.45%	.30% - 1.36%
Discounted dividends per share	**$ 1.23**	$ 1.04	$ 1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$ 22.19
Granted	278,252	19.99
Vested	—	—
Forfeited	(185,783)	30.55
Nonvested at end of period	762,154	$ 19.35

Note 14 - Income Taxes

The components of income (loss) before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2011	2010	2009
	(In thousands)		
United States	**$ 333,486**	$ 336,450	$ (227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$ (219,366)

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows:

	2011	2010	2009
		(In thousands)	
Current:			
Federal	$ (7,188)	$ 37,014	$ 64,389
State	778	10,589	8,284
Foreign	127	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Total income tax expense (benefit)	$ 110,274	$ 122,530	$ (96,092)

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 119,189	$ 114,427
Accrued pension costs	95,260	82,085
Asset retirement obligations	26,380	24,391
Legal and environmental contingencies	21,788	13,622
Compensation-related	16,241	17,261
Other	41,055	40,307
Total deferred tax assets	319,913	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	715,482	679,809
Basis differences on natural gas and oil producing properties	210,146	152,455
Regulatory matters	84,963	64,017
Intangible asset amortization	14,307	14,843
Other	23,774	20,348
Total deferred tax liabilities	1,048,672	931,472
Net deferred income tax liability	$ (728,759)	$ (639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

		2011
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	89,380
Deferred taxes associated with other comprehensive loss		9,678
Deferred taxes associated with discontinued operations		8,090
Other		11,777
Deferred income tax expense for the period	$	118,925

Total income tax expense (benefit) differs from the amount computed by applying the statutory federal income tax rate to income (loss) before taxes. The reasons for this difference were as follows:

Years ended December 31,		2011			2010			2009	
		Amount	%		Amount	%		Amount	%
					(Dollars in thousands)				
Computed tax at federal statutory rate	$	117,679	35.0	$	128,293	35.0	$	(76,778)	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax benefit (expense)		10,653	3.2		10,210	2.8		(7,280)	3.3
Resolution of tax matters and uncertain tax positions		(3,906)	(1.2)		667	.2		881	(.4)
Federal renewable energy credit		(3,485)	(1.0)		(2,185)	(.6)		(1,452)	.7
Depletion allowance		(3,266)	(1.0)		(2,810)	(.8)		(2,320)	1.0
Deductible K-Plan dividends		(2,282)	(.7)		(2,309)	(.6)		(2,369)	1.1
Foreign operations		(391)	(.1)		(588)	(.2)		(1,148)	.5
Domestic production activities deduction		—	—		—	—		(856)	.4
Other		(4,728)	(1.4)		(8,748)	(2.4)		(4,770)	2.2
Total income tax expense (benefit)	$	110,274	32.8	$	122,530	33.4	$	(96,092)	43.8

The income tax benefit in 2009 resulted largely from the Company's write-down of natural gas and oil properties, as discussed in Note 1.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2011	2010	2009
	(In thousands)		
Balance at beginning of year	$ 9,378	$ 6,148	$ 5,586
Additions for tax positions of prior years	4,172	3,230	562
Settlements	(2,344)	—	—
Balance at end of year	$ 11,206	$ 9,378	$ 6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, respectively, for the payment of interest.

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in ECTE.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in ECTE.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	$ **225,468**	$ 211,544	$ 196,171
Natural gas distribution	**907,400**	892,708	1,072,776
Pipeline and energy services	**210,846**	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	**359,873**	318,570	338,425
Construction materials and contracting	**1,509,538**	1,445,148	1,515,122
Construction services	**834,918**	786,802	818,685
Other	**2,449**	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	$ **4,050,492**	$ 3,909,695	$ 4,176,501
Intersegment operating revenues:			
Electric	$ **—**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and energy services	**67,497**	75,033	72,505
Exploration and production	**93,713**	115,784	101,230
Construction materials and contracting	**472**	—	—
Construction services	**19,471**	2,298	379
Other	**8,997**	7,580	9,487
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)
Total intersegment operating revenues	$ **—**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ **32,177**	$ 27,274	$ 24,637
Natural gas distribution	**44,641**	43,044	42,723
Pipeline and energy services	**25,502**	26,001	25,581
Exploration and production	**142,645**	130,455	129,922
Construction materials and contracting	**85,459**	88,331	93,615
Construction services	**11,399**	12,147	12,760
Other	**1,572**	1,591	1,304
Total depreciation, depletion and amortization	$ **343,395**	$ 328,843	$ 330,542

	2011	2010	2009
		(In thousands)	
Interest expense:			
Electric	$ 13,745	$ 12,216	$ 9,577
Natural gas distribution	29,444	28,996	30,656
Pipeline and energy services	10,516	9,064	8,896
Exploration and production	7,445	8,580	10,621
Construction materials and contracting	16,241	19,859	20,495
Construction services	4,473	4,411	4,490
Other	—	47	43
Intersegment eliminations	(510)	(162)	(679)
Total interest expense	$ 81,354	$ 83,011	$ 84,099
Income taxes:			
Electric	$ 7,242	$ 11,187	$ 8,205
Natural gas distribution	16,931	12,171	16,331
Pipeline and energy services	12,912	13,933	22,982
Exploration and production	46,298	49,034	(187,000)
Construction materials and contracting	11,227	13,822	25,940
Construction services	13,426	11,456	15,189
Other	2,238	10,927	2,261
Total income taxes	$ 110,274	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			
Electric	$ 29,258	$ 28,908	$ 24,099
Natural gas distribution	38,398	36,944	30,796
Pipeline and energy services	23,082	23,208	37,845
Exploration and production	80,282	85,638	(296,730)
Construction materials and contracting	26,430	29,609	47,085
Construction services	21,627	17,982	25,589
Other	6,190	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	225,267	243,335	(123,959)
Loss from discontinued operations, net of tax*	(12,926)	(3,361)	—
Total earnings (loss) on common stock	$ 212,341	$ 239,974	$ (123,959)
Capital expenditures:			
Electric	$ 52,072	$ 85,787	$ 115,240
Natural gas distribution	70,624	75,365	43,820
Pipeline and energy services	45,556	14,255	70,168
Exploration and production	272,855	355,845	183,140
Construction materials and contracting	52,303	25,724	26,313
Construction services	9,711	14,849	12,814
Other	18,759	2,182	3,196
Net proceeds from sale or disposition of property and other	(40,857)	(78,761)	(26,679)
Total net capital expenditures	$ 481,023	$ 495,246	$ 428,012

	2011	2010	2009
		(In thousands)	
Assets:			
Electric**	$ 672,940	$ 643,636	$ 569,666
Natural gas distribution**	1,679,091	1,632,012	1,588,144
Pipeline and energy services	526,797	523,075	538,230
Exploration and production	1,481,556	1,342,808	1,137,628
Construction materials and contracting	1,374,026	1,382,836	1,449,469
Construction services	418,519	387,627	328,895
Other***	403,196	391,555	378,920
Total assets	$ 6,556,125	$ 6,303,549	$ 5,990,952
Property, plant and equipment:			
Electric**	$ 1,068,524	$ 1,027,034	$ 941,791
Natural gas distribution**	1,568,866	1,508,845	1,456,208
Pipeline and energy services	719,291	683,807	675,199
Exploration and production	2,615,146	2,356,938	2,028,794
Construction materials and contracting	1,499,852	1,486,375	1,514,989
Construction services	124,796	122,940	116,236
Other	49,747	32,564	33,365
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	2,872,465
Net property, plant and equipment	$ 4,285,014	$ 4,115,180	$ 3,894,117

* *Reflected in the Other category.*

** *Includes allocations of common utility property.*

*** *Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).*

Note: The results reflect a $620.0 million ($384.4 million after tax) noncash write-down of natural gas and oil properties in 2009.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2011, 2010 and 2009 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ **388,589**	$ 352,915	$ **91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$ **—**	$ —	$ **(550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	$ **(157,618)**	$ (110,991)	$ **(42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$ **189,494**	$ 117,840	$ **43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	$ **188,862**	$ 118,471	$ **37,374**	$ 13,712

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31 were as follows:

		2011		2010
		(In thousands)		
Projected benefit obligation	**$**	**435,618**	$	388,589
Accumulated benefit obligation	**$**	**435,618**	$	374,538
Fair value of plan assets	**$**	**278,000**	$	277,598

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 2,252**	$ 2,889	$ 8,127	**$ 1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	**—**	353	—	**—**	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	**—**	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$ 74,057**	$ 19,046	$ (25,143)	**$ 25,005**	$ 2,337	$ (9,765)

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $1.9 million, $1.1 million and $2.1 million, respectively.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	4.00%	**4.00%**	4.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**5.26%**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75%**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**4.00% / N/A***	4.00%	**4.00%**	4.00%

* *Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.*

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2011	2010
Health care trend rate assumed for next year	**6.0% - 8.0%**	6.0% - 8.5%
Health care cost trend rate - ultimate	**5.0% - 6.0%**	5.0% - 6.0%
Year in which ultimate trend rate achieved	**1999 - 2017**	1999 - 2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The fair value of the Company's pension net plan assets by class is as follows:

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
		(In thousands)		
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

The fair value of the Company's other postretirement benefit plan assets by asset class is as follows:

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 59	$ 1,836	$ —	$ 1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$ 2,419	$ 65,666	$ —	$ 68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 53	$ 1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$ 3,197	$ 67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4.00 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers

- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2011	Pension Protection Act Zone Status 2010	FIP/RP Status Pending/ Implemented	Contributions **2011**	Contributions 2010	Contributions 2009	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	$ **2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					**$ 29,158**	$ 30,276	$ 32,479		

* *Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.*

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $24.0 million, $24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's 22.7 percent, 25.0 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III, respectively. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

		2011		2010
		(In thousands)		
Big Stone Station:				
Utility plant in service	$	63,715	$	60,404
Less accumulated depreciation		42,475		41,136
	$	21,240	$	19,268
Coyote Station:				
Utility plant in service	$	131,719	$	131,395
Less accumulated depreciation		86,788		84,710
	$	44,931	$	46,685
Wygen III:*				
Utility plant in service	$	63,300	$	63,215
Less accumulated depreciation		2,106		838
	$	61,194	$	62,377

* *Began commercial operation on April 1, 2010.*

Note 18 - Regulatory Matters and Revenues Subject to Refund

On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012.

On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012.

On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

Guarantees

Centennial guaranteed CEM's obligations under a construction contract. For further information, see Litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Definitions

Abbreviation or Acronym

AFUDC	Allowance for funds used during construction
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the fourth quarter of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (7.51 percent ownership interest at December 31, 2011, 2.5 and 14.99 percent ownership interest was sold in 2011 and 2010, respectively)

EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu

MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent - natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
Oil	Includes crude oil, condensate and natural gas liquids
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
PRC	Planning resource credit - a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2012 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of natural gas and oil during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SMCRA	Surface Mining Control and Reclamation Act
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada

WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

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MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2011

Operating Income	
Electric Utility	
Operating Revenues	$223,201,621
Operating Expenses:	
Operation Expenses	114,687,315
Maintenance Expenses	17,703,292
Depreciation Expenses	32,005,151
Taxes Other Than Income Taxes	9,434,923
Income Taxes:	
Federal Taxes on Income	(12,586,738)
State Taxes on Income	(1,265,099)
Deferred Income Taxes	21,167,194
Total Electric Expenses	181,146,038
Net Electric Operation	$42,055,583
Gas Utility	
Operating Revenues	$282,824,029
Operating Expenses:	
Operation Expenses	245,406,477
Maintenance Expenses	3,630,918
Depreciation Expenses	11,248,859
Taxes Other Than Income Taxes	6,935,664
Income Taxes:	
Federal Taxes on Income	(10,601,531)
State Taxes on Income	(1,461,534)
Deferred Income Taxes	14,025,870
Total Gas Expenses	269,184,723
Net Gas Operation	$13,639,306
Net Utility Operating Income	$55,694,889
Revenues from Merchandising, Jobbing and Contract Work	$6,056,315
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	4,666,614
Revenues from Nonutility Operations	4,113,607
(Less) Expense from Nonutility Operations	2,581,985
Equity in Earnings of Subsidiary Companies	171,763,717
Interest and Dividend Income	1,717,382
Allowance for Other Funds Used During Construction	2,056,639
Miscellaneous Nonoperating Income	35,717
Gain on Disposition of Property	228,379
Total Other Income	178,723,157
Loss on Disposition of Property	(4,772)
Miscellaneous Income Deductions	1,315,568
Total Other Income Deductions	1,310,796

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2011

Taxes other than Income Taxes	3,678
Income Taxes - Federal	877,615
Income Taxes - State	332,819
Provision for Deferred Income Taxes	133,398
Investment Tax Credits	73,338
Total Taxes on Other Income and Deductions	1,420,848
Net Other Income and Deductions	$175,991,513
Interest On Long-Term Debt	17,773,282
Amortization of Debt Discount and Expense	97,309
Amortization of Loss on Reacquired Debt	719,510
Other Interest Expense	1,234,189
(Less) Allow for Borrowed Funds Used during Const.	1,164,234
Net Interest Charges	18,660,056
Net Income	$213,026,346

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
SIX MONTHS ENDING JUNE 30, 2012

Operating Income	
Electric Utility	
Operating Revenues	$110,350,568
Operating Expenses:	
Operation Expenses	59,004,234
Maintenance Expenses	9,637,198
Depreciation Expenses	15,981,140
Taxes Other Than Income Taxes	5,295,666
Income Taxes:	
Federal Taxes on Income	(3,330,057)
State Taxes on Income	(180,119)
Deferred Income Taxes	6,733,525
Total Electric Expenses	93,141,587
Net Electric Operation	$17,208,981
Gas Utility	
Operating Revenues	$120,973,856
Operating Expenses:	
Operation Expenses	101,181,009
Maintenance Expenses	1,992,632
Depreciation Expenses	5,781,526
Taxes Other Than Income Taxes	3,840,139
Income Taxes:	
Federal Taxes on Income	561,935
State Taxes on Income	(5,236)
Deferred Income Taxes	1,478,842
Total Gas Expenses	114,830,847
Net Gas Operation	$6,143,009
Net Utility Operating Income	$23,351,990
Revenues from Merchandising, Jobbing and Contract Work	$2,792,402
(Less) Costs and Exp. Of Merch., Jobbing and Contract Work	1,920,823
Revenues from Nonutility Operations	2,528,390
(Less) Expense from Nonutility Operations	1,694,800
Equity in Earnings of Subsidiary Companies	71,460,782
Interest and Dividend Income	1,219,781
Allowance for Other Funds Used During Construction	983,521
Miscellaneous Nonoperating Income	(6,361)
Gain on Disposition of Property	(28)
Total Other Income	75,362,864
Loss on Disposition of Property	0
Miscellaneous Income Deductions	212,612
Total Other Income Deductions	212,612

MDU RESOURCES GROUP, INC.
NONCONSOLIDATED INCOME STATEMENT
SIX MONTHS ENDING JUNE 30, 2012

Taxes other than Income Taxes	2,764
Income Taxes - Federal	(64,283)
Income Taxes - State	3,781
Provision for Deferred Income Taxes	(156,728)
Investment Tax Credits	(27,654)
Total Taxes on Other Income and Deductions	(242,120)
Net Other Income and Deductions	$75,392,372
Interest On Long-Term Debt	8,888,820
Amortization of Debt Discount and Expense	46,912
Amortization of Loss on Reacquired Debt	359,756
Other Interest Expense	165,899
(Less) Allow for Borrowed Funds Used during Const.	620,776
Net Interest Charges	8,840,611
Net Income	$89,903,751

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF PLANT IN SERVICE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11
Production	$2,972,781	$3,096,756	$3,034,769
Distribution	70,105,115	73,250,276	71,677,695
General	5,953,718	6,010,708	5,982,213
General Intangible	56,115	55,404	55,759
Common	10,639,185	10,552,679	10,595,932
Common Intangible	2,697,442	2,821,499	2,759,471
Subtotal	92,424,356	95,787,322	94,105,839
Construction Work in Progress (CWIP) in Service not yet Classified 1/	442,264	500,474	500,474
Total	$92,866,620	$96,287,796	$94,606,313

1/ CWIP in Service is reflected at the year end balance.

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Acct. No.	Account	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11
	Production Plant			
333	Other Gas Production Equipment	$2,972,781	$3,096,756	$3,034,769
	Distribution Plant			
374.1	Land	$15,962	$15,962	$15,962
374.2	Rights of Way	22,846	22,846	22,846
375	Structures & Improvements	195,164	195,164	195,164
376	Mains	28,343,409	28,903,239	28,623,324
378	Meas. & Reg. Equip.-General	575,341	577,021	576,181
379	Meas. & Reg. Equip.-City Gate	128,221	128,222	128,222
380	Services	19,708,913	21,208,457	20,458,685
381	Positive Meters	17,741,728	18,493,911	18,117,819
383	Service Regulators	1,908,710	2,130,129	2,019,419
385	Ind. Meas. & Reg. Station Eqpt.	187,825	187,825	187,825
386.2	Other Property on Cust. Premise	148,674	148,673	148,673
387.1	Cathodic Protection Equip.	1,010,665	1,121,405	1,066,035
387.2	Other Distribution Equip.	117,657	117,422	117,540
	Total Distribution Plant	$70,105,115	$73,250,276	$71,677,695
	General Plant			
389	Land	$7,131	$7,131	$7,131
390	Structures and Improvements	449,416	449,416	449,416
391.1	Furniture and Fixtures	50,780	48,359	49,570
391.3	Computer Equip. - PC	47,979	51,081	49,530
391.5	Computer Equip. - Other	14,561	14,561	14,561
392.1	Trans. Equip., Non-Unitized	91,540	117,486	104,513
392.2	Trans. Equip., Unitized	2,206,436	2,255,615	2,231,025
393	Stores Equipment	43,786	14,254	29,020
394.1	Tools,Shop&Gar. Eq.-Non-Un.	813,182	663,334	738,258
394.3	Vehicle Maintenance Equip.	22,859	22,859	22,859
395	Laboratory Equipment	37,072	32,303	34,688
396.1	Power Operated Equip.	138,401	151,847	145,124
396.2	Work Equipment Trailers	1,580,659	1,789,764	1,685,211
397.1	Radio Comm. Equip.-Fixed	236,876	237,224	237,050
397.2	Radio Comm. Equip.-Mobile	197,928	140,365	169,147
398	Miscellaneous Equipment	15,112	15,109	15,110
	Total General Plant	$5,953,718	$6,010,708	5,982,213
303	Intangible Plant - General	$56,115	$55,404	$55,759

MONTANA-DAKOTA UTILITIES CO.
PLANT IN SERVICE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Acct. No.	Account	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11
	Common Plant			
389	Land	$952,893	$988,648	$970,771
390	Structures and Improvements	7,115,215	6,978,927	7,047,071
391.1	Furniture and Fixtures	384,341	497,432	440,886
391.3	Computer Equip. - PC	349,039	391,997	370,518
391.5	Computer Equip. - Other	96,481	11,912	54,197
392.1	Trans. Equip., Non-Unitized	6,228	6,203	6,215
392.2	Trans. Equip., Unitized	543,334	584,835	564,085
392.3	Aircraft	466,754	483,574	475,164
393	Stores Equipment	10,796	10,773	10,784
394	Tools, Shop & Gar. Equip.	46,925	53,148	50,037
394.3	Vehicle Maint. Equip.	44,019	44,545	44,282
394.4	Vehicle Refueling Equip.	66,439	28,124	47,281
396.2	Work Equipment Trailers	6,458		3,229
397.1	Radio Comm. Equip.-Fixed	160,188	149,997	155,093
397.2	Radio Comm. Equip.-Mobile	100,652	77,331	88,991
397.3	General Tele. Comm. Equip.	40,103	76,218	58,161
397.5	Supervisory & Tele. Equip.	450	223	336
397.8	Network Equipment	122,906	56,252	89,579
398	Miscellaneous Equipment	125,964	112,540	119,252
	Total Common Plant	$10,639,185	$10,552,679	$10,595,932
303	Intangible Plant - Common	$2,697,442	$2,821,499	$2,759,471
	Total Gas Plant in Service	$92,424,356	$95,787,322	$94,105,839

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Function	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11
Production		$101,594	$50,797
Distribution	$42,010,598	43,776,099	42,893,349
General	3,281,698	3,073,666	3,177,682
General Intangible	56,115	55,405	55,760
Common	2,937,562	3,016,552	2,977,057
Common Intangible	2,010,597	2,198,479	2,104,538
Total	$50,296,570	$52,221,795	$51,259,183

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF WORKING CAPITAL AND OTHER DEDUCTIONS
INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Working Capital	Balance @ 12/31/10	Balance @ 12/31/11	Average	Pro Forma Adjustments	Pro Forma Balances	Adjustment
Materials and Supplies	$508,979	$557,694	$533,337	$99,695	$633,032	A
Gas in Underground Storage	6,702,686	7,566,845	7,134,766	(855,502)	6,279,264	B
Prepayments						
Insurance	23,075	28,741	25,908	93,808	119,716	C
Demand and Commodity	1,086,349	1,213,615	1,149,981	(642,915)	507,066	D
Unamortized Loss on Debt	631,135	538,504	584,820		584,820	
Provision for Pension & Benefits				1,268,837	1,268,837	E
Provision for Injuries & Damages				(109,736)	(109,736)	F
Deferred FAS 106 Balance	148,226	109,558	128,892	273,775	402,667	G
Total Working Capital	$9,100,450	$10,014,957	$9,557,704	$127,962	$9,685,666	
Customer Advances for Construction	$770,737	$683,775	$727,256	($20,926)	$706,330	H

MONTANA-DAKOTA UTILITIES CO.
MATERIALS AND SUPPLIES - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT A

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$508,979	$557,694	
January 2011	491,311	571,628	
February	490,913	609,874	
March	483,398	609,597	
April	553,150	672,668	
May	559,282	824,045	
June	567,033	862,822	
July	573,017	573,017	
August	567,190	567,190	
September	607,577	607,577	
October	609,349	609,349	
November	606,259	606,259	
December	557,694	557,694	
Beginning and ending average	$533,337		
Thirteen month average		$633,032	$99,695

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects per books 2011.

MONTANA-DAKOTA UTILITIES CO.
GAS IN UNDERGROUND STORAGE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT B

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$6,702,686	$7,566,845	
January 2011	3,072,842	5,288,653	
February	(103,277)	3,279,980	
March	(1,865,166)	3,263,233	
April	(1,935,039)	3,670,275	
May	(722,093)	4,755,047	
June	1,462,708	6,049,593	
July	4,109,292	7,436,157	
August	6,884,778	8,380,580	
September	9,880,135	9,015,463	
October	11,499,125	8,977,527	
November	10,018,059	8,212,063	
December	7,566,845	5,735,018	
Beginning and ending average	$7,134,766		
Thirteen month average		$6,279,264	($855,502)

1/ Reflects actual balances December 2011 through June 2012 and July - December based on planned injections and withdrawals.

MONTANA-DAKOTA UTILITIES CO.
PREPAID INSURANCE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT C

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$23,075	$28,741	
January 2011	221,728	244,853	
February	214,702	225,487	
March	193,742	203,043	
April	172,792	180,600	
May	151,843	158,489	
June	130,893	136,036	
July	109,943	112,699	
August	88,994	89,362	
September	68,044	66,025	
October	52,716	42,691	
November	49,466	43,763	
December	28,741	24,517	
Beginning and ending average	$25,908		
Thirteen month average		$119,716	$93,808

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects pro forma expense.

MONTANA-DAKOTA UTILITIES CO.
PREPAID DEMAND AND COMMODITY CHARGES - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT D

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$1,086,349	$1,213,615	
January 2011	(171,300)	(52,608)	
February	(927,762)	(897,713)	
March	(1,399,781)	(1,359,423)	
April	(1,312,777)	(1,265,136)	
May	(809,527)	(757,031)	
June	(31,451)	(18,748)	
July	785,971	729,024	
August	1,615,672	1,427,013	
September	2,428,885	2,279,771	
October	2,703,035	2,444,050	
November	2,168,667	1,937,309	
December	1,213,615	911,740	
Beginning and ending average	$1,149,981		
Thirteen month average		$507,066	($642,915)

1/ Reflects actual balances December 2011 through June 2012 and July - December based on August 2012 PGA projections.

MONTANA-DAKOTA UTILITIES CO.
UNAMORTIZED GAIN(LOSS) ON DEBT - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

	Loss on Debt	Accumulated Deferred Income Taxes
Balance at December 31, 2010	$631,135	($260,329)
Balance at December 31, 2011	538,504	(216,338)
Average Balance	$584,820	($238,334)

MONTANA-DAKOTA UTILITIES CO.
PROVISION FOR PENSIONS AND BENEFITS
ACCUMULATED DEFERRED INCOME TAXES ON PENSIONS
INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT E

	Total	Provision for Pensions	Gas DIT on Pension
Balance at December 31, 2010	$9,558	$1,594,562	($1,585,004)
Balance at December 31, 2011	9,778,591	14,596,722	(4,818,131)
Average Balance	$4,894,074	$8,095,642	($3,201,568)
Allocated to Gas Utility 1/	$4,800,716	$4,800,716	
Allocated to Montana 2/	$422,658	$1,268,837	($846,179)

1/ Pension provision is allocated to the gas utility based on payroll expense.
2/ Allocated on Net Plant in Service.

MONTANA-DAKOTA UTILITIES CO.
PROVISION FOR INJURIES AND DAMAGES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT F

	Total	Provision for Injuries and Damages	Gas DIT on Injuries and Damages
Balance at December 31, 2010	($600,130)	($963,496)	$363,366
Balance at December 31, 2011	(351,375)	(568,573)	217,198
Average Balance	($475,753)	($766,035)	$290,282
Allocated to Gas Utility 1/	($257,858)	($415,191)	$157,333
Allocated to Montana 2/	($68,153)	($109,736)	$41,583

1/ Allocated on insurance expense.
2/ Allocated on Net Plant in Service.

MONTANA-DAKOTA UTILITIES CO.
DEFERRED FAS 106 BALANCE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT G

	Total	Deferred FAS 106	Deferred Inc Tax -FAS 106
Balance at December 31, 2010	$89,821	$148,226	($58,405)
Balance at December 31, 2011	66,388	109,558	(43,170)
Average Balance	$78,105	$128,892	($50,788)
Pro Forma Average Balance 1/	$246,024	$402,667	($156,643)
Pro Forma Adjustment		$273,775	($105,855)

1/ Reflects levelization of balance pursuant to Order No. 5856g in Docket No. D95.7.90.

MONTANA-DAKOTA UTILITIES CO.
CUSTOMER ADVANCES FOR CONSTRUCTION - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT H

	Per Books	Pro Forma 1/	Pro Forma Adjustment
December 2010	$770,737	$683,775	
January 2011	724,483	684,920	
February	715,446	696,451	
March	718,039	696,780	
April	718,071	711,981	
May	721,821	712,080	
June	707,803	712,141	
July	710,955	710,955	
August	711,296	711,296	
September	714,768	714,768	
October	723,118	723,118	
November	740,251	740,251	
December	683,775	683,775	
Beginning and ending average	$727,256		
13 month average		$706,330	($20,926)

1/ Reflects actual balances December 2011 through June 2012 and July - December reflects per books 2011.

MONTANA-DAKOTA UTILITIES CO.
CAPITAL STRUCTURE - INTERIM
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA 2012

	Balance	Ratio	Cost	Weighted Cost
Per Books				
Long Term Debt	$280,492,390	43.316%	6.845%	2.965%
Short Term Debt 1/	1,933,973	0.299%	13.053%	0.039%
Preferred Stock	15,450,000	2.386%	4.588%	0.109%
Common Equity	349,672,199	53.999%	10.500%	5.670%
Total	$647,548,562	100.000%		8.783%
Pro Forma				
Long Term Debt	$280,485,103	39.691%	6.846%	2.717%
Short Term Debt 1/	33,568,454	4.750%	1.399%	0.066%
Preferred Stock	15,350,000	2.172%	4.583%	0.100%
Common Equity	377,270,918	53.387%	10.500%	5.606%
Total	$706,674,475	100.000%		8.489%

1/ Reflects average monthly balance.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

	Montana	Pro Forma Adjustments	Pro Forma
Production	$188,558	$1,315	$189,873
Cost of Gas	52,735,031	(13,880,459)	38,854,572
Other Gas Supply	73,609	2,489	76,098
Distribution	4,322,878	147,213	4,470,091
Customer Accounts	1,948,083	32,737	1,980,820
Customer Service & Infor.	89,100	2,637	91,737
Sales	119,573	3,824	123,397
Administrative and General	4,127,510	(53,784)	4,073,726
Total Operation and Maintenance Expenses	$63,604,342	($13,744,028)	$49,860,314

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Account No.	Description	Per Books	Pro Forma Adjustments	Pro Forma
	Production			
754	Field Compressor Station	$188,558		
	Total Production Expenses	$188,558	$1,315	$189,873
	Other Gas Supply Expenses			
804	Natural Gas City Gate Purchases	$54,043,984		
805.1	Purchased Gas Cost Adjustments	52,394		
808.1	Gas Withdrawn from Storage	11,534,090		
808.2	Gas Delivered to Storage	(12,895,437)		
813	Other Gas Supply Expenses	73,609		
	Total Other Gas Supply Expenses	$52,808,640	($13,877,970)	$38,930,670
	Distribution Expenses			
	Operation			
870	Supervision and Engineering	$514,850		
871	Distribution Load Dispatching	74,482		
874	Mains and Services	1,138,366		
875	Measuring & Reg. Station Exp. - General	34,815		
876	Measuring & Reg. Station Exp. - Industrial	14,521		
878	Meters and House Regulators	267,551		
879	Customer Installations	538,992		
880	Other Expenses	832,223		
881	Rents	33,379		
	Total Operation Expenses	$3,449,179		
	Maintenance			
885	Supervision & Engineering	$130,671		
886	Structures & Improvements	1,179		
887	Mains	138,093		
889	Measuring & Reg. Station Exp. - General	28,158		
890	Measuring & Reg. Station Exp. - Industrial	15,721		
892	Services	155,111		
893	Meters and House Regulators	284,028		
894	Other Equipment	120,738		
	Total Maintenance Expenses	$873,699		
	Total Distribution Expenses	$4,322,878	$147,213	$4,470,091
	Customer Accounts Expenses			
	Operation			
901	Supervision	$96,853		
902	Meter Reading Expenses	230,640		
903	Customer Records and Collection Exp.	1,376,127		
904	Uncollectible Accounts	173,361		
905	Misc. Customer Accounts Expenses	71,102		
	Total Customer Accounts Expenses	$1,948,083	$32,737	$1,980,820

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

Account No.	Description	Per Books	Pro Forma Adjustments	Pro Forma
	Customer Service & Information Expenses			
	Operation			
907	Supervision	$28,529		
908	Customer Assistance Expenses	11,125		
909	Informational and Instructional Expenses	29,421		
910	Misc. Customer Service & Info. Exp.	20,025		
	Total Customer Service & Info. Exp.	$89,100	$2,637	$91,737
	Sales Expenses			
	Operation			
911	Supervision	$22,826		
912	Demonstrating and Selling Expenses	72,731		
913	Advertising Expenses	12,258		
916	Misc. Sales Expenses	11,758		
	Total Sales Expenses	$119,573	$3,824	$123,397
	Administrative & General Expenses			
	Operation			
920	Administrative and General Salaries	$956,138		
921	Office Supplies and Expenses	548,659		
923	Outside Services Employed	123,948		
924	Property Insurance	80,637		
925	Injuries and Damages	263,669		
926	Employee Pensions and Benefits	1,837,398		
928	Regulatory Commission Expenses	1,742		
930	Miscellaneous General Expenses	97,390		
931	Rents	115,735		
	Total Operation Expenses	$4,025,316		
	Maintenance			
935	Maintenance of General Plant	$102,194		
	Total Maintenance Expenses	102,194		
	Total Administrative & General Expenses	$4,127,510	($53,784)	$4,073,726
	Total Operation & Maintenance Expenses	$63,604,342	($13,744,028)	$49,860,314

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA

Function	Total	Cost of Gas	Labor	Benefits	Vehicles & Work Equipment	Company Consumption	Uncollectible Accounts
Cost of Gas	$38,854,572	$38,854,572					
Other Gas Supply	76,098		$55,136		$273		
Production	189,873		29,483		921		
Distribution	4,470,091		3,551,214		401,644	$32,509	$634
Customer Accounting	1,980,820		1,105,295		49,944	9,145	158,458
Customer Service & Information	91,737		58,456		366		
Sales	123,397		90,832		2,030	1,618	
Administrative and General	4,073,726		1,069,653	$1,690,918	11,865	24,157	
Total Other O&M	11,005,742	0	5,960,069	1,690,918	467,043	67,429	159,092
Total O&M	$49,860,314	$38,854,572	$5,960,069	$1,690,918	$467,043	$67,429	$159,092
Adjustment No.		5	6	7	8	9	10
Page No.		3	4	5	6	7	8

MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA

Function	Advertising	Insurance	Industry Dues	All Other O&M
Cost of Gas				
Other Gas Supply				$20,689
Production				159,469
Distribution				484,090
Customer Accounting				657,978
Customer Service & Information				32,915
Sales				28,917
Administrative and General	$28,527	$271,973	$38,032	938,601
Total Other O&M	28,527	271,973	38,032	2,322,659
Total O&M	$28,527	$271,973	$38,032	$2,322,659
Adjustment No.	11	12	13	
Page No.	9	10	11	12

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - INTERIM
GAS UTILITY - MONTANA
ADJUSTMENT NO. 5

	Pro Forma Dk Sales 1/	Dk Adjusted for Distribution Losses 2/	Commodity Charge 3/	Pro Forma Cost of Gas
Residential	6,097,461	6,141,681	$3.829	$23,516,497
Firm General Service	3,813,826	3,841,485	3.829	14,709,046
Small Interruptible	218,586	220,171	2.857	629,029
Large Interruptible	0	0	2.857	0
Total	10,129,873	10,203,337		$38,854,572
Per Books Cost of Gas				52,735,031
Pro Forma Adjustment				($13,880,459)

1/ Rule 38.5.164, Statement H, page 2.
2/ Distribution loss factor of .72%.
3/ August 2012 PGA adjusted to reflect annual commodity costs.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
LABOR EXPENSE - INTERIM
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 6

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Other Gas Supply	$183,219	$52,641	$55,136	$2,495
Production	97,971	28,149	29,483	1,334
Distribution	12,308,950	3,390,504	3,551,214	160,710
Customer Accounting	3,355,405	1,055,275	1,105,295	50,020
Customer Service	279,619	55,811	58,456	2,645
Sales	297,894	86,721	90,832	4,111
A&G	3,528,635	1,021,246	1,069,653	48,407
Total	$20,051,693	$5,690,347	$5,960,069	$269,722

1/ Reflects a 4.74% increase made up of a 2.5% increase for non-union employees and 3.0% increase for union employees. Also includes the three-year amortization of severance pay recorded in 2009.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 7

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Medical/Dental	$2,117,808	$623,431	$628,980	$5,549
Pension expense	514,314	155,387	(64,455)	(219,842)
Post-retirement	453,151	152,499	384,206	231,707
401-K	2,145,671	605,091	689,804	84,713
Workers compensation	114,735	50,015	52,383	2,368
Supplemental Insurance	617,368	179,996	0	(179,996)
Total	$5,963,047	$1,766,419	$1,690,918	($75,501)

1/ Reflects an increase of 0.89% to medical and dental, a decrease of 141.48% to Pension expense an increase of 151.94% to Post-retirement expense, an increase of 14% to 401-K expense. Workers Compensation expense is based on the ratio of worker's compensation to pro forma labor expense and Supplemental Insurance was eliminated from benefits expense.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
VEHICLES AND WORK EQUIPMENT - INTERIM
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 8

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Other Gas Supply	$970	$279	$273	($6)
Production	$3,271	940	921	(19)
Distribution	1,379,130	410,016	401,644	(8,372)
Customer Accounting	137,048	50,998	49,944	(1,054)
Customer Service	7,549	374	366	(8)
Sales	9,728	2,073	2,030	(43)
A&G	44,626	12,115	11,865	(250)
Total	$1,582,322	$476,795	$467,043	($9,752)

1/ Based on pro forma plant and current depreciation rates.

MONTANA-DAKOTA UTILITIES CO.
COMPANY CONSUMPTION - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 9

	Per Books - Total			Pro Forma
	Total Utility	Montana	Pro Forma	Adjustment
Distribution	$210,890	$37,574	$32,509	($5,065)
Customer Accounting	59,780	10,471	9,145	(1,326)
Sales	13,488	1,862	1,618	(244)
A&G	87,948	25,642	24,157	(1,485)
Total	$372,106	$75,549	$67,429	($8,120)

	Per Books - Electric			Pro Forma
	Electric Utility	Montana	Pro Forma	Adjustment
Distribution	$72,800	$13,591	$13,591	$0
Customer Accounting	27,758	4,193	4,193	0
Sales	6,025	705	705	0
A&G	63,836	18,612	18,612	0
Total Electric	$170,419	$37,101	$37,101	$0

	Per Books - Gas			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Distribution	$138,090	$23,983	$18,918	($5,065)
Customer Accounting	32,022	6,278	4,952	(1,326)
Sales	7,463	1,157	913	(244)
A&G	24,112	7,030	5,545	(1,485)
Total Gas	$201,687	$38,448	$30,328	($8,120)

1/ Reflects a 21.12% decrease to reflect annualized firm sales revenue at current rates.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
UNCOLLECTIBLE ACCOUNTS - INTERIM
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 10

	Per Books		Pro Forma	Pro Forma
	Gas Utility	Montana	Montana 1/	Adjustment
Distribution	$580	$694	$634	($60)
Customer Accounting	591,673	173,361	158,458	(14,903)
Total	$592,253	$174,055	$159,092	($14,963)

1/ Based on 5 year average of write-offs to revenues applied to pro forma revenues.

MONTANA-DAKOTA UTILITIES CO.
ADVERTISING EXPENSE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 11

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Informational	$105,127	$29,421	$28,527	($894)
Promotional	59,631	12,258	0	(12,258)
Institutional	92,168	18,504	0	(18,504)
Total	$256,926	$60,183	$28,527	($31,656)

1/ Eliminates promotional and institutional advertising expenses and informational expenses not applicable to Montana gas operations.

MONTANA-DAKOTA UTILITIES CO.
INSURANCE EXPENSE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 12

A&G Expense for Insurance	Total Company Per Books	Montana Per Books	Montana Pro Forma 1/	Pro Forma Adjustment
Director's & Officer's Liability Insurance	$71,660	$18,256	$16,710	($1,546)
Excess Liability				
Fiduciary & Employee Benefits Liability	27,454	6,994	6,826	(168)
Public Liab. & Property Ins. Damage of Others	597,609	152,247	139,860	(12,387)
All Risk	313,900	79,969	107,764	27,795
Blanket Crime	2,620	668	705	37
Special Contingency		0	108	108
	$1,013,243	$258,134	$271,973	$13,839

1/ Adjusted to reflect insurance expense at current levels.

MONTANA-DAKOTA UTILITIES CO.
INDUSTRY DUES - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 13

	Per Books Montana	Pro Forma		Pro Forma Adjustment
American Gas Association 1/	$20,413	$18,860	2/	($1,553)
Chamber of Commerce-Baker 3/	50	30		(20)
Chamber of Commerce-Billings 3/	2,274	1,500	2/	(774)
Chamber of Commerce-Glasgow 3/	145	87	2/	(58)
Chamber of Commerce-Glendive 3/	134	80		(54)
Chamber of Commerce-Hardin 3/	227	150	2/	(77)
Chamber of Commerce-Laurel 2/	464	306	2/	(158)
Chamber of Commerce-Malta 3/	200	204	2/	4
Chamber of Commerce-Prairie County 3/	21	13		(8)
Chamber of Commerce-Sidney 3/	242	145		(97)
Chamber of Commerce-Wibaux 3/	20	12		(8)
Chamber of Commerce-Wolf Point 3/	460	276	2/	(184)
Chamber of Commerce-Miles City 3/	302	181		(121)
Home Builders Association of Billings	346	228	2/	(118)
Montana Economic Developers Association	25	25		0
Richland Economic Development	950	950		0
Dawson County Economic Development	760	760		0
Big Sky Economic Development	0	2,500	2/	2,500
Bureau of Business and Economic Development	2,280	2,280		0
Metrapark Foundation	910	910		0
Miles City Area Economic Development Council	161	161		0
Midwest Region Gas Task Force	255	255		0
Midwest Energy Association	7,846	7,626	2/	(220)
Montana Water Resources Association	135	135		0
United Telecom Council	334	334		0
Custer County Art Center	24	24		0
Other	6,192	0		(6,192)
Total Industry Dues	$45,170	$38,032		($7,138)

1/ Lobbying portion excluded from amounts recorded.
2/ Pro Forma reflects actual 2012 amount.
3/ Pro Forma reflects the elimination of lobbying expenses as a percentage of annual dues.

MONTANA-DAKOTA UTILITIES CO.
OTHER O&M - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Per Books Other O & M	Items Adjusted Individually	Other O & M
Other Gas Supply	$73,609	$52,920	$20,689
Production	188,558	29,089	159,469
Distribution	4,322,878	3,838,788	484,090
Customer Accounting	1,948,083	1,290,105	657,978
Customer Service & Information	89,100	56,185	32,915
Sales	119,573	90,656	28,917
Administrative and General	4,127,510	3,188,909	938,601
Total Other O&M	$10,869,311	$8,546,652	$2,322,659

MONTANA-DAKOTA UTILITIES CO.
O&M ITEMS ADJUSTED INDIVIDUALLY - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Per Books	Cost of Gas	Labor	Benefits	Vehicles & Work Equipment	Company Consumption	Uncollectible Accounts	Advertising
Cost of Gas	$52,735,031	$52,735,031						
Other Gas Supply	73,609		$52,641		$279			
Production	188,558		28,149		940			
Distribution	4,322,878		3,390,504		410,016	$37,574	$694	
Customer Accounting	1,948,083		1,055,275		50,998	10,471	173,361	
Customer Service & Information	89,100		55,811		374			
Sales	119,573		86,721		2,073	1,862		
Administrative and General	4,127,510		1,021,246	$1,766,419	12,115	25,642		$60,183
Total Other O&M	10,869,311	0	5,690,347	1,766,419	476,795	75,549	174,055	60,183
Total O&M	$63,604,342	$52,735,031	$5,690,347	$1,766,419	$476,795	$75,549	$174,055	$60,183

MONTANA-DAKOTA UTILITIES CO.
O&M ITEMS ADJUSTED INDIVIDUALLY - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	Insurance	Industry Dues	Total items adjusted individually	All Other O&M
Cost of Gas			$52,735,031	
Other Gas Supply			52,920	$20,689
Production			29,089	159,469
Distribution			3,838,788	484,090
Customer Accounting			1,290,105	657,978
Customer Service & Information			56,185	32,915
Sales			90,656	28,917
Administrative and General	$258,134	$45,170	3,188,909	938,601
Total Other O&M	258,134	45,170	8,546,652	2,322,659
Total O&M	$258,134	$45,170	$61,281,683	$2,322,659

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUES - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Per Books	Pro Forma Adjustments	Pro Forma
Sales			
Residential	$45,522,909	($9,792,993)	$35,729,916
Firm General	26,717,947	(5,461,164)	21,256,783
Small Interruptible	1,382,090	(577,308)	804,782
Large Interruptible	107,192	(107,192)	0
Unbilled Revenue	(1,240,879)	1,240,879	0
Total Sales	$72,489,259	($14,697,778)	$57,791,481
Transportation			
Small Interruptible	$619,197	($36,468)	$582,729
Large Interruptible	647,477	(98,673)	548,804
Unbilled Revenue	(13,785)	13,785	0
Total Transportation	$1,252,889	($121,356)	$1,131,533
Total Sales and Transportation	$73,742,148	($14,819,134)	$58,923,014
Other Revenue			
Misc. Service Revenue	$45,335	$0	$45,335
Rent from Property	244,709	0	244,709
Other Revenue	78,782	47,286	126,068
Total Other Revenue	$368,826	$47,286	$416,112
Total Operating Revenue	$74,110,974	($14,771,848)	$59,339,126

Docket No. ____
Rule 38.5.164
Statement H
Page 2 of 7

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUES - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011

	Per Books		Per Books @ Current Rates		Normalized @ Current Rates		Annualized @ Current Rates	
	Dk	Revenue	Dk	Revenue	Dk	Revenue	DK	Revenue
Sales								
Residential	6,268,127	$45,522,909	6,268,127	$36,569,220	6,082,510	$35,644,290	6,097,461	$35,729,916
Firm General Service	3,814,964	26,717,947	3,814,964	21,257,139	3,781,959	21,085,183	3,813,826	21,256,783
Small Interruptible	278,445	1,382,090	278,445	1,021,471	218,586	804,782	218,586	804,782
Large Interruptible	23,609	107,192	23,609	80,712	0	0	0	0
Unbilled Revenue	0	(1,240,879)	0	0	0	0	0	0
Total Sales	10,385,145	$72,489,259	10,385,145	$58,928,542	10,083,055	$57,534,255	10,129,873	$57,791,481
Transportation								
Small Interruptible	728,209	619,197	728,209	613,831	686,293	582,729	686,293	582,729
Large Interruptible	4,614,240	647,477	4,614,240	590,446	4,197,933	548,804	4,197,933	548,804
Unbilled Revenue	0	(13,785)	0	0	0	0	0	0
Total Transportation	5,342,449	1,252,889	5,342,449	1,204,277	4,884,226	1,131,533	4,884,226	1,131,533
Total	15,727,594	$73,742,148	15,727,594	$60,132,819	14,967,281	$58,665,788	15,014,099	$58,923,014

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 1

	Per Books		Per Books @ Current Rates		
	Dk	Revenue	Dk	Revenue 1/	Adjustment
Sales					
Residential	6,268,127	$45,522,909	6,268,127	$36,569,220	($8,953,689)
Firm General Service	3,814,964	26,717,947	3,814,964	21,257,139	(5,460,808)
Small Interruptible	278,445	1,382,090	278,445	1,021,471	(360,619)
Large Interruptible	23,609	107,192	23,609	80,712	(26,480)
Unbilled Revenue	0	(1,240,879)	0	0	1,240,879
Total Sales	10,385,145	$72,489,259	10,385,145	$58,928,542	(13,560,717)
Transportation					
Small Interruptible	728,209	619,197	728,209	613,831	(5,366)
Large Interruptible	4,614,240	647,477	4,614,240	590,446	(57,031)
Unbilled Revenue	0	(13,785)	0	0	13,785
Total Transportation	5,342,449	1,252,889	5,342,449	1,204,277	(48,612)
Total	15,727,594	$73,742,148	15,727,594	$60,132,819	($13,609,329)

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 2

	Per Books @ Current Rates		Normalized Dk @ Current Rates		
	Dk	Revenue 1/	Dk	Revenue 1/	Adjustment
Sales					
Residential	6,268,127	$36,569,220	6,082,510	$35,644,290	($924,930)
Firm General Service	3,814,964	21,257,139	3,781,959	21,085,183	(171,956)
Small Interruptible	278,445	1,021,471	218,586	804,782	(216,689)
Large Interruptible	23,609	80,712	0	0	(80,712)
Unbilled Revenue	0	0	0	0	0
Total Sales	10,385,145	$58,928,542	10,083,055	$57,534,255	(1,394,287)
Transportation					
Small Interruptible	728,209	613,831	686,293	582,729	(31,102)
Large Interruptible	4,614,240	590,446	4,197,933	548,804	(41,642)
Unbilled Revenue	0	0	0	0	0
Total Transportation	5,342,449	1,204,277	4,884,226	1,131,533	(72,744)
Total	15,727,594	$60,132,819	14,967,281	$58,665,788	($1,467,031)

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
SALES AND TRANSPORTATION REVENUE - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 3

	Normalized Dk @ Current Rates		Annualized Dk @ Current Rates		
	Dk	Revenue 1/	DK	Revenue 1/	Adjustment
Sales					
Residential	6,082,510	$35,644,290	6,097,461	$35,729,916	$85,626
Firm General Service	3,781,959	21,085,183	3,813,826	21,256,783	171,600
Small Interruptible	218,586	804,782	218,586	804,782	0
Large Interruptible	0	0	0	0	0
Unbilled Revenue	0	0	0	0	0
Total Sales	10,083,055	$57,534,255	10,129,873	$57,791,481	257,226
Transportation					
Small Interruptible	686,293	582,729	686,293	582,729	0
Large Interruptible	4,197,933	548,804	4,197,933	548,804	0
Unbilled Revenue	0	0	0	0	0
Total Transportation	4,884,226	1,131,533	4,884,226	1,131,533	0
Total	14,967,281	$58,665,788	15,014,099	$58,923,014	$257,226

1/ Reflects current rates with August 2012 gas cost tracking adjustment adjusted to reflect annual gas commodity costs.

MONTANA-DAKOTA UTILITIES CO.
OTHER OPERATING REVENUES - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 4

	Per Books	Pro Forma Adjustments		Pro Forma
Misc. Service Revenue				
Seasonal Reconnect Fee	$1,480	$0		$1,480
NSF Check Fees	28,025	0		28,025
Work for Construction of Others	10,236	0		10,236
Other Misc. Service Revenue	5,594	0		5,594
Total Misc. Service Revenue	$45,335	$0		$45,335
Rent from Property	244,709	0		244,709
Other Revenue				
Sale of Sundry Junk Material	$878	$0		$878
Sale of Operating Construct. Mat.	475	0		475
Patronage Dividends	1,912	0		1,912
Miscellaneous	39,440	0		39,440
Late Payments Revenue		45,851		45,851
Gain/(Loss) on Disposal of Property		17,770	1/	17,770
Penalty Revenue	36,077	(16,335)	2/	19,742
Total Other Revenue	$78,782	$47,286		$126,068
Total Other Operating Revenue	$368,826	$47,286		$416,112

1/ Amortization of gain/(loss) on sale of plant over five year period.
2/ Restates penalty revenue to a three year average.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER INTERIM RATES
GAS UTILITY - MONTANA
Pro Forma 2012

Customer Class/Rate	Pro Forma 1/ Customers	Dk	Revenue	Total Proposed Interim Revenue 1/	Proposed Interim Revenue Increase	Percent Increase
Residential - Rate 60	70,161	6,097,461	$35,729,916	$34,632,056	$1,097,860	3.1%
Firm General Service - Rates 70 & 72	8,700	3,813,826	21,256,783	20,668,221	588,562	2.8%
Small Interruptible						
Sales - Rate 71	9	218,586	804,782	804,782		
Transport - Rates 81	35	686,293	582,729	582,729		
Total Small Interruptible	44	904,879	1,387,511	1,387,511	0	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0	0		
Transport - Rate 82	5	4,197,933	548,804	548,804		
Total Large Interruptible	5	4,197,933	548,804	548,804	0	0.0%
Total Montana	78,910	15,014,099	$58,923,014	$57,236,592	$1,686,422	2.9%

1/ Rule 38.5.177, Statement M, Page 1.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	2011 Per Books	Pro Forma Adjustment	Pro Forma Expense 1/
Production	$101,594	($536)	$101,058
Distribution	2,367,765	42,440	2,410,205
General	115,122	(1,090)	114,032
Common	315,830	(1,980)	313,850
Common - Intangible	110,987	(29,700)	81,287
CWIP in Service			2/
Total	$3,011,298	$9,134	$3,020,432

1/ See page 2.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 14

Function	2011 Per Books	Pro Forma Expense 1/	Pro Forma Adjustment
Production	$101,594	$101,058	($536)
Distribution	2,367,765	2,410,205	42,440
General	115,122	114,032	(1,090)
Common	315,830	313,850	(1,980)
Common - Intangible	110,987	81,287	(29,700)
CWIP in Service		2/	2/
Total	$3,011,298	$3,020,432	$9,134

1/ Average annual depreciation expense on pro forma plant in service, see Rule 38.5.165, Statement I, pages 3-4.
2/ Included in the above functions.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 14

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation
	Production Plant			
333	Other Gas Production Equipment	$3,034,769	3.33%	$101,058
	Distribution Plant			
374.1	Land	$15,962		
374.2	Rights of Way	22,846	1.39%	$318
375	Structures & Improvements	195,164	1.81%	3,532
376	Mains	28,623,324	2.08%	595,365
378	Meas. & Reg. Equip.-General	576,181	3.29%	18,956
379	Meas. & Reg. Equip.-City Gate	128,222	2.81%	3,603
380	Services	20,458,685	5.75%	1,176,374
381	Positive Meters	18,117,819	2.91%	527,229
383	Service Regulators	2,019,419	1.57%	31,705
385	Ind. Meas. & Reg. Station Eqpt.	187,825	2.43%	4,564
386.2	Other Property on Cust. Premise	148,673	0.27%	401
387.1	Cathodic Protection Equip.	1,066,035	3.21%	34,220
387.2	Other Distribution Equip.	117,540	0.99%	1,164
	Total Distribution Plant	$71,677,695		$2,397,431
	General Plant			
389	Land	$7,131		
390	Structures and Improvements	449,416	3.09%	$13,887
391.1	Furniture and Fixtures	49,570	8.33%	4,129
391.3	Computer Equip. - PC	49,530	20.00%	9,906
391.5	Computer Equip. - Other	14,561	20.00%	2,912
392.1	Trans. Equip., Non-Unitized	104,513	9.67% 2/	
392.2	Trans. Equip., Unitized	2,231,025	0.26% 2/	
393	Stores Equipment	29,020	2.86%	830
394.1	Tools,Shop&Gar. Eq.-Non-Un.	738,258	6.36%	46,953
394.3	Vehicle Maintenance Equip.	22,859	5.00%	1,143
395	Laboratory Equipment	34,688	7.11%	2,466
396.1	Power Operated Equip.	145,124	6.02% 2/	
396.2	Work Equipment Trailers	1,685,211	0.23% 2/	
397.1	Radio Comm. Equip.-Fixed	237,050	7.42%	17,589
397.2	Radio Comm. Equip.-Mobile	169,147	7.13%	12,060
398	Miscellaneous Equipment	15,110	7.87%	1,189
	Total General Plant	$5,982,213		$113,064
303	Intangible Plant - General	55,759	3/	$0

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 14

Acct. No.	Account	Pro Forma Average Plant 1/	Depreciation Rate	Annual Depreciation
	Common Plant			
389	Land	$970,771		
390	Structures and Improvements	7,047,071	2.25%	$158,559
391.1	Furniture and Fixtures	440,886	7.61%	33,551
391.3	Computer Equip. - PC	370,518	9.76%	36,163
391.5	Computer Equip. - Other	54,197	20.00%	10,839
392.1	Trans. Equip., Non-Unitized	6,215	0.00% 3/	
392.2	Trans. Equip., Unitized	564,085	4.11% 2/	
392.3	Aircraft	475,164	3.77%	17,914
393	Stores Equipment	10,784	3.57%	385
394.1	Tools, Shop & Gar. Equip.	50,037	5.79%	2,897
394.3	Vehicle Maint. Equip.	44,282	5.59%	2,475
394.4	Vehicle Refueling Equip.	47,281	5.48%	2,591
396.2	Work Equipment Trailers 2/	3,229	7.58%	
397.1	Radio Comm. Equip.-Fixed	155,093	6.69%	10,376
397.2	Radio Comm. Equip.-Mobile	88,991	6.67%	5,936
397.3	General Tele. Comm. Equip.	58,161	10.00%	5,816
397.5	Supervisory & Tele. Equip.	336	6.69%	22
397.8	Network Equipment	89,579	20.00%	17,916
398	Miscellaneous Equipment	119,252	5.40%	6,440
	Total Common Plant	$10,595,932		$311,880
303	Intangible Plant - Common	2,759,471	2.95%	$81,294
	CWIP in Service 5/			
	Distribution	$382,467	3.34%	$12,774
	General	51,213	1.89%	968
	Common	67,043	2.94%	1,970
	Intangible - Common	(249)	2.95%	(7)
	Total CWIP	$500,474		$15,705
	Total Gas Plant in Service	$94,606,313		$3,020,432

1/ See Rule 38.5.123, Statement C, pages 2 - 3.
2/ Charged to a clearing account.
3/ Fully amortized/depreciated.
4/ Amortization based on the life of each item.
5/ Composite rates by function.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION AND AMORTIZATION EXPENSES
INTERIM

See Pages 6 and 7 for Montana-Dakota's currently effective depreciation rates as of December 31, 2011.

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES - INTERIM
GAS UTILITY - MONTANA
CURRENT DEPRECIATION AND AMORTIZATION RATES 1/

		Depreciation Rate
	Distribution Plant	
374.2	Rights of Way	1.39%
375	Structures & Improvements	1.81%
376	Mains	2.08%
378	Meas. & Reg. Equip.-General	3.29%
379	Meas. & Reg. Equip.-City Gate	2.81%
380	Services	5.75%
381	Positive Meters	2.91%
383	Service Regulators	1.57%
385	Ind. Meas. & Reg. Station Eqpt.	2.43%
386.2	Other Property on Cust. Premise	0.27%
387.1	Cathodic Protection Equip.	3.21%
387.2	Other Distribution Equip.	0.99%
	General Plant	
390	Structures and Improvements	3.09%
391.1	Furniture and Fixtures	8.33%
391.3	Computer Equip. - PC	20.00%
391.5	Computer Equip. - Other	20.00%
392.1	Trans. Equip., Non-Unitized	9.67%
392.2	Trans. Equip., Unitized	0.26%
393	Stores Equipment	2.86%
394.1	Tools,Shop&Gar. Eq.-Non-Un.	6.36%
394.3	Vehicle Maintenance Equip.	5.00%
395	Laboratory Equipment	7.11%
396.1	Power Operated Equip.	6.02%
396.2	Work Equipment Trailers	0.23%
397.1	Radio Comm. Equip.-Fixed	7.42%
397.2	Radio Comm. Equip.-Mobile	7.13%
398	Miscellaneous Equipment	7.87%
303	Intangible Plant - General	0.00% 2/
	Common Plant	
390	Structures and Improvements	2.25%
391.1	Furniture and Fixtures	7.61%
391.3	Computer Equip. - PC	9.76%
391.5	Computer Equip. - Other	20.00%
392.1	Trans. Equip., Non-Unitized	0.00%
392.2	Trans. Equip., Unitized	4.11%
392.3	Aircraft	3.77%
393	Stores Equipment	3.57%

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES - INTERIM
GAS UTILITY - MONTANA
CURRENT DEPRECIATION AND AMORTIZATION RATES 1/

		Depreciation Rate
394.1	Tools, Shop & Gar. Equip.	5.79%
394.3	Vehicle Maint. Equip.	5.59%
394.4	Vehicle Refueling Equip.	5.48%
396.2	Work Equipment Trailers 2/	7.58%
397.1	Radio Comm. Equip.-Fixed	6.69%
397.2	Radio Comm. Equip.-Mobile	6.67%
397.3	General Tele. Comm. Equip.	10.00%
397.5	Supervisory & Tele. Equip.	6.69%
397.8	Network Equipment	20.00%
398	Miscellaneous Equipment	5.40%
303	Intangible Plant - Common	2.95%

1/ Depreciation rates from the 2008 Gas and Common Depreciation studies. Distribution rates have been adjusted to reflect the current cost of removal rates. General and common plant rates reflect the effective rates as of December 31, 2011 as such plant is a mix of depreciated and amortized plant.

2/ Fully amortized.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO PER BOOKS TAXABLE INCOME
INTERIM
ELECTRIC UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Operating Income	Adjustment No.	Pro Forma Adjustment	Reference
Current Income Taxes			
Interest Expense Annualization 1/	18	($85,734)	Statement J, Page 2
Other Tax Deductions	19	(400,022)	Statement J, Page 3
Total Adjustment to Taxable Income		($485,756)	
Income Taxes on Pro Forma Adjustments	20	(164,579)	Statement J, Page 4
Elimination of Closing/Filing and prior-perioc	21	1,560,882	Statement J, Page 5
Total Adjustment to Current Income Taxes		$1,396,303	
Deferred Income Taxes			
Elimination of Closing/Filing and prior-period	21	(1,302,970)	Statement J, Page 5
Other Tax Deductions	19	38,579	Statement J, Page 3
Total Adjustment to Deferred Income Taxes		($1,264,391)	
Rate Base			
Accumulated Deferred Income Taxes -			
Normalization	I	(53,293)	Statement J, Page 7
Pensions and Benefits	E	846,179	Statement E, Page 6
Injuries and Damages	F	(41,583)	Statement E, Page 7
Deferred FAS 106 costs	G	105,855	Statement E, Page 8
Total Adjustment to Current Income Taxes		$857,158	
Accumulated Investment Tax Credits	J	(4,084)	Statement J, Page 8

1/ Amount is shown before income tax effect.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ADJUSTMENT FOR INTEREST EXPENSE ANNUALIZATION - INTERIM
ADJUSTMENT NO. 18

	Per Books	Pro Forma Adjustment	Pro Forma
Rate Base 1/	$43,247,498	($704,186)	$42,543,312
Weighted Cost of Debt 2/			2.783%
Interest Expense - Pro Forma			$1,183,980
Interest Charges as Recorded 3/			1,269,714
Interest Expense Annualization Adjustment			($85,734)

1/ Rule 38.5.175, Overall Cost of Service, page 1.
2/ Rule 38.5.146, Statement F, page 1, Long and Short Term Debt.
3/ Reflects long and short term interest and amortization of loss on debt.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
OTHER TAX DEDUCTIONS - INTERIM
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 19

	Pro Forma Adjustment
1900 Account Other Tax Deductions	
Supplemental Income Security Plan	$95,291
Permanent Deduction	
Supplemental Income Security Plan	(101,090)
Unamortized Gain on SISP	133,317
Adjustment to eliminate 401(k) Dividend Deduction	(527,540)
Total tax deductions	($400,022)
Deferred Income Taxes	
Supplemental Income Security Plan	$38,579

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
CALCULATION OF ADJUSTMENT TO
CURRENT INCOME TAXES - INTERIM
ADJUSTMENT NO. 20

	Pro Forma Adjustments
Operating Revenues	
Sales Revenues	($14,697,778)
Transportation Revenues	($121,356)
Other Revenues	47,286
Total Operating Revenues	(14,771,848)
Operating Expenses	
Operation and Maintenance	
Cost of Gas	(13,880,459)
Other O&M	136,431
Total O&M	(13,744,028)
Depreciation Expense	9,134
Taxes other Than Income	(133,351)
Total Operating Expenses	(13,868,245)
Gross Adjustments to Operating Income	(903,603)
Deductions and Adjustments to Book Income:	
Interest Annualization 1/	(85,734)
Other Tax Deductions 2/	(400,022)
Total Adjustments to Taxable Income	(485,756)
Taxable Income	(417,847)
Federal & State Income Taxes @ 39.3875%	($164,579)
Elimination of Federal & State Prior Period Adj.	1,560,882
Total Adjustment to Current Income Taxes	$1,396,303

1/ Rule 38.5.169, Statement J, page 2.
2/ Rule 38.5.169, Statement J, page 3.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ADJUSTMENT TO CURRENT AND DEFERRED INCOME TAXES
FOR ROUNDING AND PRIOR YEAR'S AND CLOSING/FILING
INTERIM
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 21

Adjustment to Current Federal Income Taxes to Eliminate Closing/Filing and Prior Period Adjustments	$1,560,882
Adjustment to Deferred Income Taxes to Eliminate Closing/Filing and Prior Period Adjustments	($1,302,970)

MONTANA-DAKOTA UTILITIES CO.
ACCUMULATED DEFERRED INCOME TAXES
ACCUMULATED INVESTMENT TAX CREDITS
INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

	Balance @ 12/31/10	Balance @ 12/31/11	Average Balance @ 12/31/11	Pro Forma Adjustments	Pro Forma Balance	Adjustment
Liberalized Depreciation	$6,707,373	$9,327,091	$8,017,232	$0	$8,017,232	
Full Normalization	574,000	576,594	575,297	(53,293)	522,004	I
Prepaid Demand Charges	325,048	336,723	330,885		330,885	
Customer Advances	(303,671)	(269,408)	(286,540)		(286,540)	
Unamortized Loss on Debt	260,329	216,338	238,334		238,334	
Provision for Pensions & Benefits				846,179	846,179	E
Provision for Injuries & Damages				(41,583)	(41,583)	F
Deferred FAS 106	58,405	43,170	50,788	105,855	156,643	G
Balance	$7,621,484	$10,230,508	$8,925,996	$857,158	$9,783,154	
Accumulated Investment Tax Credits						
Balance	$6,977	$1,191	$4,084	($4,084)	$0	J

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES
TO REFLECT FULL NORMALIZATION - INTERIM
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT I

Amortization of deferred taxes to reflect full normalization	($53,293)

MONTANA-DAKOTA UTILITIES CO.
INVESTMENT TAX CREDITS
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT J

	Montana
Balance at December 31, 2010	$6,977
Balance at December 31, 2011	1,191
Average Balance	$4,084
Pro Forma Adjustment	($4,084)

MONTANA-DAKOTA UTILITIES CO.
TAXES OTHER THAN INCOME - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011

Type of Tax	Total Company	Montana	Pro Forma Adjustments	Pro Forma	Adjustment No.
Ad Valorem					
Production	$224,065	$64,378	$0	$64,378	
Distribution	3,158,386	2,086,403	11,124	2,097,527	
General	217,734	87,648	748	88,396	
Common	366,005	265,647	1,684	267,331	
Intangible	16,559	0	0	0	
Total Ad Valorem Taxes	$3,982,749	$2,504,076	$13,556	$2,517,632	15
O&M Related Taxes - Other					
Payroll Taxes	$1,492,978	$428,471	$20,322	$448,793	16
Franchise	112,752				
Delaware Franchise	66,160	19,066		19,066	
Total O&M Related Taxes	$1,671,890	$447,537	$20,322	$467,859	
Revenue Taxes					
Montana PSC	$272,846	272,846	(154,920)	117,926	17
Montana Consumer Counsel	83,064	83,064	(12,309)	70,755	17
South Dakota	78,816				
Wyoming	46,999				
	$481,725	$355,910	($167,229)	$188,681	
Other					
Highway Use Tax	$719	$210		$210	
Secretary of State	992	286		286	
Total Other	$1,711	$496	$0	$496	
Total Taxes Other Than Income	$6,138,075	$3,308,019	($133,351)	$3,174,668	

MONTANA-DAKOTA UTILITIES CO.
AD VALOREM TAXES - INTERIM
GAS UTILITY - MONTANA
ADJUSTMENT NO. 15

		Pro Forma		Per Books	
Function	Effective Tax Rate	Plant Balance 2/	Ad Valorem Tax	Ad Valorem Tax	Pro Forma Adjustment
Production	2.1213%	$3,034,769	$64,378	$64,378	$0
Distribution	2.9108%	72,060,162	2,097,527	2,086,403	11,124
General	1.4651%	6,033,426	88,396	87,648	748
Common	2.5071%	10,662,975	267,331	265,647	1,684
Intangible 1/	0.0000%	2,814,981	0	0	0
Total Ad Valorem Taxes		$94,606,313	$2,517,632	$2,504,076	$13,556

1/ General and Common intangible.
2/ Includes CWIP in service.

MONTANA-DAKOTA UTILITIES CO.
PAYROLL TAXES - INTERIM
GAS UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2011
ADJUSTMENT NO. 16

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Payroll Taxes	$1,492,978	$428,471	$448,793	$20,322

1/ Pro Forma labor expense multiplied by ratio of payroll taxes to 2011 labor expense.

MONTANA-DAKOTA UTILITIES CO.
ADJUSTMENT TO CONSUMER COUNSEL TAX
AND PSC TAX - INTERIM
GAS UTILITY - MONTANA
ADJUSTMENT NO. 17

Pro Forma Revenue 1/	$58,923,014
Miscellaneous Revenue 2/	39,741
Taxable Revenue	58,962,755
Consumer Counsel Tax @ 0.12% 2/	70,755
Per Books Consumer Counsel Tax	83,064
Pro Forma Adjustment	(12,309)
PSC Tax @ 0.2% 2/	117,926
Per Books PSC Tax	272,846
Pro Forma Adjustment	(154,920)
Pro Forma Adjustment	($167,229)

1/ Rule 38.5.164, Statement H, page 5.
2/ Includes revenues for seasonal reconnect fees, NSF check fees, and work for construction of others.
3/ Tax rate effective October 1, 2011.

Docket No. ____
Rule 38.5.177
Statement M

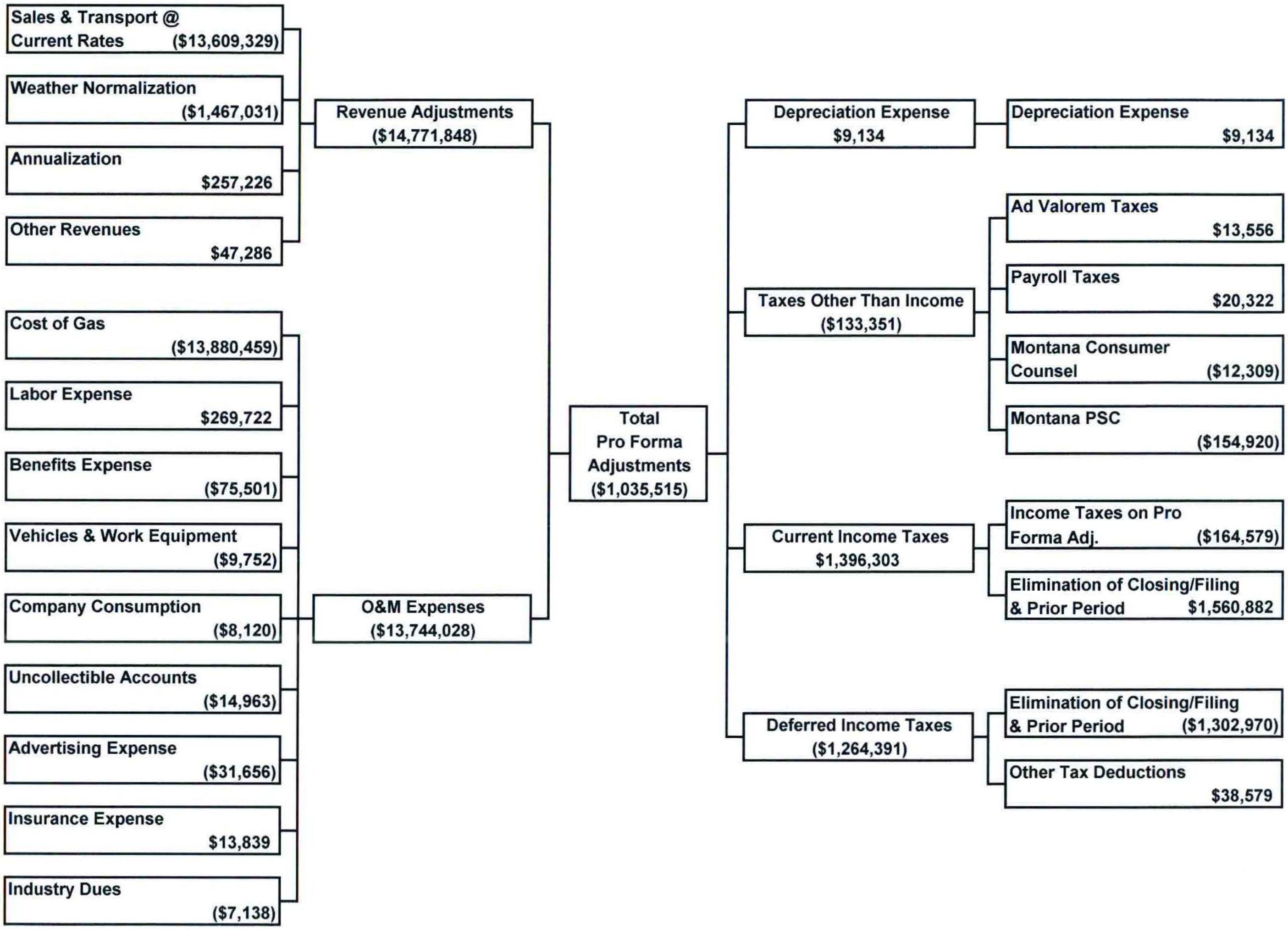
MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
ALLOCATION OF REVENUE INCREASE & RESULTS OF PROPOSED INTERIM RATE DESIGN
Pro Forma 2012

Rate Class	Customers	Dk	Basic Service Charge	Distribution Delivery	Gas Costs	Total Revenues 1/	Proposed Interim Increase 2/ $	Proposed Interim Increase 2/ % 3/
Residential	70,161	6,097,461	$5,346,268	$6,865,741	$23,517,907	$35,729,916	$1,097,860	3.07%
Firm General								
Small Firm General	6,547	1,119,203	817,066	1,514,282	4,316,766	6,648,114	209,588	
Large Firm General	2,153	2,694,623	569,683	3,645,825	10,393,161	14,608,669	378,974	
Total Firm General	8,700	3,813,826	1,386,749	5,160,107	14,709,927	21,256,783	588,562	2.77%
Small Interruptible								
Sales	9	218,586	13,500	162,191	629,091	804,782	0	
Transportation	35	686,293	73,500	509,229	0	582,729	0	
Total Small IT	44	904,879	87,000	671,420	629,091	1,387,511	0	0.00%
Large Interruptible								
Sales	0	0	0	0	0	0	0	
Transportation	5	4,197,933	31,800	517,004	0	548,804	0	
Total Large IT	5	4,197,933	31,800	517,004	0	548,804	0	0.00%
Total Montana	78,910	15,014,099	$6,851,817	$13,214,272	$38,856,925	$58,923,014	$1,686,422	2.86%

Residential & Firm General Revenues - Interim (excluding Cost of Gas)	$18,758,865
Requested Interim Revenue Increase	1,686,101
% Increase applied to bills (excluding Cost of Gas)	8.99%

1/ Rule 38.5.177, Statement M, Page 1.
2/ Increase applied to Residential and Firm General based on increase in Basic Service Charge and Distribution Delivery revenues of 8.99%.
3/ Percentage increase in total revenues.

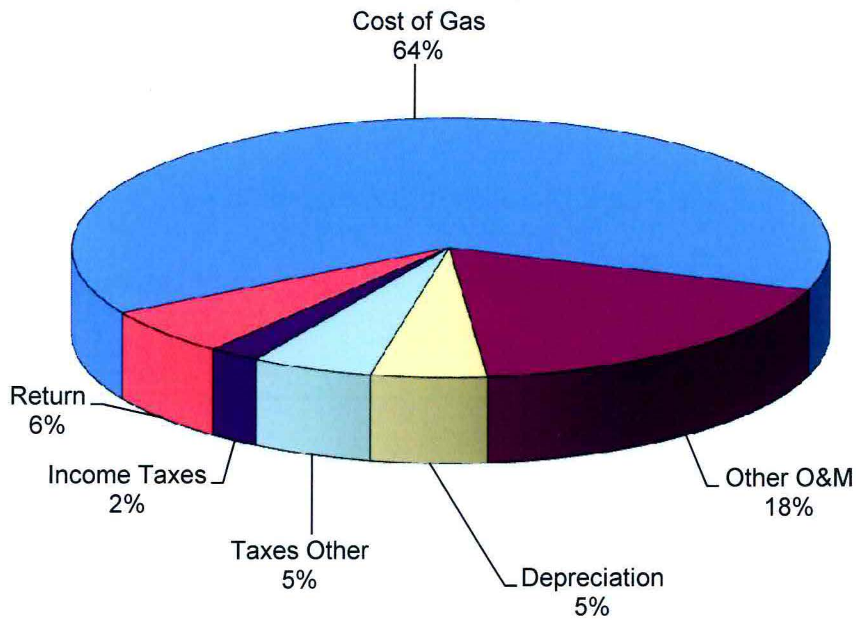
MONTANA-DAKOTA UTILITIES CO.
FLOWCHART OF INTERIM PRO FORMA ADJUSTMENTS TO OPERATING INCOME



MONTANA-DAKOTA UTILITIES CO.
FLOWCHART OF INTERIM PRO FORMA ADJUSTMENTS TO RATE BASE

Item	Amount
Materials & Supplies	$99,695
Gas in Underground Storage	($855,502)
Prepaid Insurance	$93,808
Prepaid Demand & Commodity	($642,915)
Provision for Pensions & Benefits	$1,268,837
Provision for Injuries & Damages	($109,736)
Deferred FAS 106 Costs	$273,775
Additions	**$127,962**
Accumulated Def. Inc. Tax - Normalization	($53,293)
Accumulated Def. Inc. Tax - Def. FAS 106	$105,855
Accumulated Def. Inc. Tax - Pensions & Benefits	$846,179
Accumulated Def. Inc. Tax - Injuries and Damages	($41,583)
ITCs	($4,084)
Customer Advances for Construction	($20,926)
Deductions	**$832,148**
Total Pro Forma Adjustments	**($704,186)**

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF REVENUE REQUIREMENTS - INTERIM



Revenue Requirement - Interim	
Cost of Gas	$38,854,572
Other O&M	11,005,742
Depreciation	3,020,432
Taxes Other	3,180,064
Income Taxes	1,352,915
Return	3,611,502
Miscellaneous Revenue	(416,112)
Total	$60,609,115

MONTANA-DAKOTA UTILITIES CO.
GAS DIVISION

Depreciation Study
as of December 31, 2008

AUS Consultants

AUS CONSULTANTS
792 Old Highway 66, Suite 200
Tijeras, NM 87059
PHONE: (717) 763-9890
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E-MAIL: erobinson@wfw-ausinc.com

Earl M. Robinson, CDP
Principal & Director

January 28, 2010

Mr. Paul Bienek
Montana-Dakota Utilities Company
400 North Fourth Street
Bismark, ND 58501

Dear Mr. Bienek:

Re: MDU Gas Depreciation Study

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Montana-Dakota Utilities Company - Gas Division as of December 31, 2008. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2008 results in an annual depreciation expense of $9,698,264. In comparison, the application of the proposed depreciation rates to the depreciable plant in service at December 31, 2008 results in an annual depreciation expense of $10,224,058, which is a increase of $525,793 from current rates. The composite annual depreciation rate under present rates is 3.85 percent, while the proposed pro forma composite depreciation rate is 4.06 percent.

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON, CDP

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SECTION 2 (continued)

TABLE OF CONTENTS

MONTANA-DAKOTA UTILITIES COMPANY
Gas

Executive Summary

Table 1 on pages 2-1 to 2-2 is a comparative summary which illustrates the effect of instituting the revised depreciation rates. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Montana Dakota Utilities Company – Gas (the "Company") plant in service as of December 31, 2008. Both the present and proposed depreciation rates were developed utilizing the Straight Line (SL) Method, Broad Group (BG) Procedure, and the Average Remaining Life (ARL) Technique. The utilization of the recommended depreciation rates based upon the Straight Line Average Remaining Life Procedure results in the setting of depreciation rates which will continuously true up the Company's level of capital recovery over the life of each asset group. Application of this procedure, which is based upon the current best estimates of service life and net salvage together with the Company's plant in service and accrued depreciation, produces annual depreciation rates that will result in the Company recovering 100 percent of its investment -- no more, no less.

Table 1a on pages 2-3 and 2-4 summarizes the segmentation of the Company's property group's December 31, 2008 book depreciation reserves into the plant only, gross salvage, and cost of removal components.

Table 2 - Plant Only on pages 2-5 through 2-7, (which is the development of average remaining life depreciation rates for the Plant Only recovery component) provides a summary of

the detailed life estimates and service life parameters utilized in preparing the Average Remaining Life depreciation rates for each property group. The schedule provides a summary of the detailed data and narrative of the study results set forth in Sections 4 through 7. The developed depreciation rates (Column I) were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property. This study included an analysis of the content of the property groups, discussions with senior management regarding current and anticipated events that may impact the various property groups.

Table 2 - Gross Salvage on pages 2-8 through 2-10 is a similar table to Table 2 – Plant Only, except that this table develops the component level depreciation rates for the recovery of the gross salvage portion of the property cost.

Table 2 - Cost of Removal on pages 2-11 through 2-13 summarizes the depreciation recovery rates for the cost of removal segment of the total plant cost.

Table 3 on pages 2-14 and 2-15 reconciles the December 31, 2008 account level plant in service balances per books versus the balances utilized in the performance of the depreciation study. The table incorporates pending (unrecorded) retirements identified during the course of completing the depreciation study.

Likewise, Table 4, on pages 2-16 and 2-17, reconciles the December 31, 2008 book depreciation reserve balances per books versus the balances utilized in preparing the depreciation rates per this study. The table incorporates the pending (unrecorded) retirements identified in assembling the detailed accounting data for this study.

Table 5, on pages 2-18 to 2-20, contains a summary of the Company's book depreciation reserve versus the corresponding theoretical depreciation reserve as of December 31, 2008. The theoretical depreciation reserves were developed using each asset category's utility plant in service as of December 31, 2008 together with the current estimated service life characteristics and net salvage factors developed per the study.

Table 6 on page 2-21 summarizes the annual amortization rates and amounts for each of the general plant accounts for which the depreciation amortization approach is being used while Table 7 on page 2-22 to 2-35 are the supporting detail calculations that develop the amortization rates. The amortization of the investments within the selected general plant accounts is driven by the Company's ongoing difficulty to effectively track various of the property account investments that are in many cases related to a large quantity of items of corresponding small investment amounts. Due to the inability to effectively track the items, many times the items are no longer utilized but remain on the company's books and records as unrecorded retirements. Therefore, the accounting procedure for these property items it that the investments within each vintage of the applicable property group is amortized over a predetermined time period. Once attaining the stated amortization period age the asset's original cost investment will have been fully amortized, and accordingly, is retired from the company's books and records. The property accounts for which asset investment amortization is being used includes Account 391, 393, 394, 395, 397, and 398.

In the process of amortization of the selected general plant accounts, there are, by the very nature of average service life dispersion, vintage investments with the applicable property group which exceeds the estimated average service life / proposed amortization period. Given that each vintage of property will be amortized over the average service life an adjustment needs to be incorporated into the change over process to recover the under depreciated position of those older investments. Accordingly, the variance between the amortization starting point depreciation reserve and the Company's actual book reserve (either positive or negative) is being recorded on a straight line basis over the proposed amortization period along with the annual amortization of all other vintage investments. The amortization starting point book depreciation reserve is equal to the sum of the original cost for vintage older than the amortization period plus the calculated deprecation reserve for vintages with ages equal to or less than the amortization period.

It is recommended that the Company continue to apply depreciation rates and maintain its book depreciation reserve on an account-level basis. The maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Maintaining the Company's depreciation records in this detail will aid in completing the various rate studies and, most importantly, clearly identifies the Company's level of capital recovery relative to each category of plant investment.

The general drivers for the proposed depreciation rates include an assessment of the Company's historical experience with regard to achieved service lives and net salvage factors. In addition, consideration is given to current and anticipated events which are anticipated to impact the Company's ability to recover its fixed capital costs related to utility plant in service utilized to provide service to the Company's customers.

The depreciation rate for each individual account changed as a result of reflecting estimates obtained through the in-depth analysis of the Company's most recent data together with an interpretation of ongoing and anticipated future events. Some of the revisions were not significant and typically reflect fine tuning of previously utilized depreciation rates while others were more substantial in nature. Several of the accounts did reflect more significant changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates.

The most notable depreciation/amortization occurred relative to Account 376 - Mains, Account 380 - Services, Account 391.1 - Office Furniture and Equipment, Account 391.5 - Computer Equipment - Other and Account 392.20 - Transportation Equipment - Cars & Trucks.

The proposed depreciation rate for Account 376 – Mains, increased from 1.92 percent to 2.97 percent. The proposed depreciation rate is the result of combined changes of both the average service life and net salvage parameters for the various property categories that comprise the overall plant account. Based upon the Company's actual historical plant in service data individual service life parameters were estimated for each of the primary property groups (including Steel, Plastic, Valves, Manholes, and Bridge and River Crossings) as outlined in section 4 of the depreciation study report. The proposed average service life for each sub property group was changed in accordance with the life indication developed through an analysis of the Company's historical data and consideration of future expectations. The resulting proposed composite average service life of the various property groups is forty-seven (47) years, while the average service life underlying the present depreciation rate is an implicit forty-five (45) years. The future net salvage underlying the proposed depreciation rates is negative 50 percent while the future net salvage underlying the present depreciation rates is negative 60 percent. Notwithstanding the fact that both the estimated average service life was lengthen and the negative net salvage was reduced in developing the proposed depreciation rate, the resulting rate increased. Accordingly, the ARL depreciation rate increase is being driven by the fact that the current book depreciation reserve is at a lower level than required relative to the estimated depreciation parameters and currently average age of the property groups.

The proposed depreciation rate for Account 380 – Services, increased from 5.66 percent to 8.18 percent. The proposed depreciation rate is the result of combined changes of both the average service life and net salvage parameters for the various property categories that comprise the overall plant account. Based upon the Company's actual historical plant in service data individual service life parameters were estimated for each of the primary property groups (including Steel, Plastic, and Farm and Fuel Lines) as outlined in section 4 of the depreciation study report. The proposed average service life for each sub property group was changed in accordance with the life indication developed through an analysis of the Company's historical data and consideration of future expectations. The resulting proposed composite average service life of the various property groups is an implicit forty (40) years, which is the same forty (40) year implicit average service life underlying the present implicit depreciation rate. The future net salvage underlying the proposed depreciation rates is negative two hundred (200) percent while the future net salvage underlying the present depreciation rates is negative one hundred seventy five (175) percent and is reflective of the increased level of negative net salvage being experienced by the company.

The depreciation rate relative to Account 392.20 - Transportation Equipment - Cars & Trucks decreased from 21.13 percent to 0.00 percent. The current estimated average service life is 7 years and the net salvage factor is estimated at 15 percent. The depreciation rate decrease is the product of the fact that the current plant in service investment is fully depreciated. Given the typical shorter average service life experienced by this property class, the depreciable life, net salvage rate and resulting annual depreciation rate requires more frequent review than has previously occurred. To the extent that significant retirements of existing property investments and additions of new property investments occur in the coming intervening years (and the current fully depreciated status of the property group declines significantly) a depreciation rate of 12.14 percent (based upon the 7 year average service life and 15 percent net salvage) should be utilized until the next depreciation study is performed.

Various of the remaining account/sub-accounts experienced increases and/or declines in recommended depreciation rates to a lesser degree, as noted per Table 1 of this report. This revision in annual depreciation rates and expense is the result of both changes in the estimated service lives and salvage factors, and reflects the impact of the Company's property changes since the most recent study.

With regard to the inclusion of higher negative net salvage levels in the development of proposed depreciation rates, as noted within my discussion related to net salvage both in Section 3 of the depreciation report, the level of experienced net salvage should simply be a benchmark from which to estimate future net salvage. It is highly likely that the negative net salvage amounts experienced even recently will simply be the floor above which future negative net salvage levels will increase to a higher level. To appropriately and proportionately allocate the true total asset cost (original cost adjusted for net salvage) over its applicable service life, proper consideration must be given in each accounting period, to the total costs that are anticipated to occur relative to the Company's assets that provide customer service.

Applying the proposed depreciation rates to the Company's December 31, 2008 plant in service produces annual depreciation/amortization expense of $10,224,058 which is a increase of $525,793 from current depreciation rates.

The following summary compares the present and proposed composite depreciation rates for illustrative purposes only. The Composite Depreciation Rate should not be applied to the total Company investment inasmuch as the non-proportional change in plant investment as a result of property additions or retirements would render the composite rate inappropriate. The Table 1 schedule lists the recommended annual depreciation rates for each property account.

Present Depreciation Rates

Depreciable Plant In Service at December 31, 2008	$251,825,094
Annual Depreciation Expense	9,698,264
Composite Annual Depreciation Rate	3.85%

Proposed Depreciation Rates

Depreciable Plant In Service at December 31, 2008	$251,825,094
Annual Depreciation Expense	10,224,058
Composite Annual Depreciation Rate	4.06%

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

			Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Gross Salv Rates		Proposed COR Rates		Total Proposed Rates		
Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Rate % (d)	Annual Accrual (e)	Rate % (f)	Annual Accrual (g)	Rate % (h)	Annual Accrual (i)	Rate % (j)	Annual Accrual (k)	Rate % (l)	Annual Accrual (m)	Net Change Depr.. Exp. (n)
	DEPRECIABLE PLANT												
	Distribution Plant												
374.20	Rights of Way	322,677.60	0.75%	2,420.08	1.39%	4,485.22	0.00%	0.00	0.00%	0.00	1.39%	4,485.22	2,065.14
375.00	Distr. Meas & Reg Station Structures	609,311.11	2.57%	15,659.30	1.52%	9,261.53	0.18%	1,096.76	1.07%	6,519.63	2.77%	16,877.92	1,218.62
	Mains												
376.10	Mains-Steel	41,975,049.45	1.92%	805,920.95	1.77%	742,958.38	0.00%	0.00	1.07%	449,133.03	2.84%	1,192,091.40	386,170.45
376.20	Mains-Plastic	63,935,958.79	1.92%	1,227,570.41	1.99%	1,272,325.58	0.00%	0.00	1.06%	677,721.16	3.05%	1,950,046.74	722,476.33
376.30	Mains-Valves	447,328.09	1.92%	8,588.70	2.29%	10,243.81	0.00%	0.00	1.25%	5,591.60	3.54%	15,835.41	7,246.71
376.40	Mains-Manholes	69,919.29	1.92%	1,342.45	1.83%	1,279.52	0.00%	0.00	1.06%	741.14	2.89%	2,020.67	678.22
376.50	Mains-Bridge & River Crossings	19,818.03	1.92%	380.51	2.06%	408.25	0.00%	0.00	1.07%	212.05	3.13%	620.30	239.79
	Total Mains	106,448,073.65	1.92%	2,043,803.02	1.90%	2,027,215.54	0.00%	0.00	1.06%	1,133,398.98	2.97%	3,160,614.52	1,116,811.50
378.00	Meas & Reg Station Equip-General	2,140,308.63	2.96%	63,353.14	2.22%	47,514.85	0.00%	0.00	0.92%	19,690.84	3.14%	67,205.69	3,852.55
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	3.54%	36,420.29	2.81%	28,909.90	0.00%	0.00	0.94%	9,670.93	3.75%	38,580.82	2,160.53
	Services												
380.10	Services-Steel	7,285,187.87	5.66%	412,341.63	2.48%	180,672.66	0.00%	0.00	7.17%	522,347.97	9.65%	703,020.63	290,679.00
380.20	Services-Plastic	42,690,273.23	5.66%	2,416,269.46	2.50%	1,067,256.83	0.00%	0.00	5.41%	2,309,543.78	7.91%	3,376,800.61	960,531.15
380.30	Farm & Fuel Lines	248,640.18	5.66%	14,073.03	3.34%	8,304.58	0.00%	0.00	7.67%	19,070.70	11.01%	27,375.28	13,302.25
	Total Services	50,224,101.28	5.66%	2,842,684.12	2.50%	1,256,234.07	0.00%	0.00	5.68%	2,850,962.45	8.18%	4,107,196.52	1,264,512.40
381.00	Meters	55,172,050.24	3.19%	1,759,988.40	2.91%	1,605,506.66	0.00%	0.00	0.62%	342,066.71	3.53%	1,947,573.37	187,584.97
383.00	Service Regulators	5,555,207.98	2.59%	143,879.89	2.16%	119,992.49	-0.39%	(21,665.31)	0.00%	0.00	1.77%	98,327.18	(45,552.71)
385.00	Industrial Meas. & Reg. Station Equip	875,376.89	3.04%	26,611.46	2.43%	21,271.66	0.35%	3,063.82	0.53%	4,639.50	3.31%	28,974.98	2,363.52
	MISCELLANEOUS EQUIPMENT												
386.10	Misc Property on Customers Premise	1,679.84	5.19%	87.18	2.39%	40.15	0.00%	0.00	0.00%	0.00	2.39%	40.15	(47.03)
386.20	CNG Refueling station	261,880.34	3.70%	9,689.57	0.27%	707.08	0.00%	0.00	0.00%	0.00	0.27%	707.08	(8,982.49)
386.30	CNG Lease/Demo	0.00											
	TOTAL Account 386	263,560.18	3.71%	9,776.75	0.28%	747.23	0.00%	0.00	0.00%	0.00	0.28%	747.23	(9,029.52)
	OTHER EQUIPMENT												
387.10	Cathodic Protection Equipment	1,737,817.71	5.75%	99,924.52	3.21%	55,783.95	0.00%	0.00	0.00%	0.00	3.21%	55,783.95	(44,140.57)
387.20	Other Distribution Equipment	588,025.51	1.42%	8,349.96	0.99%	5,821.45	0.00%	0.00	0.00%	0.00	0.99%	5,821.45	(2,528.51)
	TOTAL Account 387	2,325,843.22	4.66%	108,274.48	2.65%	61,605.40	0.00%	0.00	0.00%	0.00	2.65%	61,605.40	(46,669.08)
	TOTAL Distribution Plant	224,965,332.67	3.14%	7,052,870.93	2.30%	5,182,744.55	-0.01%	(17,504.73)	1.94%	4,366,949.04	4.24%	9,532,188.85	2,479,317.92
	General Plant												
390.00	General Structures	5,835,295.28	3.73%	217,656.51	3.09%	180,310.62	-0.04%	(2,334.12)	0.41%	23,924.71	3.46%	201,901.22	(15,755.29)
	OFFICE FURNITURE & EQUIPMENT												
391.10	Office Furniture & Equipment	415,861.93	4.97%	20,668.34	6.59%	27,412.62	0.00%	0.00	0.00%	0.00	6.59%	27,412.62	6,744.28
391.30	Computer Equipment - PC	828,118.21	26.02%	215,476.36	11.28%	93,383.50	0.00%	0.00	0.00%	0.00	11.28%	93,383.50	(122,092.86)
391.50	Other Computer Equipment	53,696.84	0.00%	0.00	4.97%	2,667.08	0.00%	0.00	0.00%	0.00	4.97%	2,667.08	2,667.08
	TOTAL Account 391	1,297,676.98	18.20%	236,144.70	9.51%	123,463.20	0.00%	0.00	0.00%	0.00	9.51%	123,463.20	(112,681.50)

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

			Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Rates: Proposed Gross Salv Rates		Proposed Rates: Proposed COR Rates		Proposed Rates: Total Proposed Rates		
Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Rate % (d)	Annual Accrual (e)	Rate % (f)	Annual Accrual (g)	Rate % (h)	Annual Accrual (i)	Rate % (j)	Annual Accrual (k)	Rate % (l)	Annual Accrual (m)	Net Change Depr.. Exp. (n)
	TRANSPORTATION EQUIPMENT												
392.10	Transportation Equipment (Trailers)	397,059.69	4.36%	17,311.80	12.35%	49,036.87	-2.68%	(10,641.20)	0.00%	0.00	9.67%	38,395.67	21,083.87
392.20	Trans Equipment (Cars & Trucks)	8,775,094.21	21.13%	1,854,177.41	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	(1,854,177.41)
	TOTAL Account 392	9,172,153.90	20.40%	1,871,489.21	0.53%	49,036.87	-0.12%	(10,641.20)	0.00%	0.00	0.42%	38,395.67	(1,833,093.54)
393.00	Stores Equipment	148,282.28	2.49%	3,692.23	2.44%	3,613.53	0.00%	0.00	0.00%	0.00	2.44%	3,613.53	(78.70)
	TOOLS, SHOP & GARAGE EQ.												
394.10	Tools, Shop & Garage Equip. (Non-Uni	2,515,638.89	6.62%	166,535.29	5.65%	142,108.78	0.00%	0.00	0.00%	0.00	5.65%	142,108.78	(24,426.51)
394.30	Vehicle Maintenance Equipment	37,100.02	5.78%	2,144.38	7.12%	2,640.27	0.00%	0.00	0.00%	0.00	7.12%	2,640.27	495.89
394.40	Vehicle Refueling Equipment	26,852.90	4.72%	1,267.46	10.32%	2,772.05	0.00%	0.00	0.00%	0.00	10.32%	2,772.05	1,504.59
	TOTAL Account 394	2,579,591.81	6.59%	169,947.13	5.72%	147,521.10	0.00%	0.00	0.00%	0.00	5.72%	147,521.10	(22,426.03)
395.00	Laboratory Equipment	172,283.97	7.67%	13,214.18	6.95%	11,980.02	0.00%	0.00	0.00%	0.00	6.95%	11,980.02	(1,234.16)
	POWER OPERATED EQUIPMENT												
396.10	Work Equipment (Trailers)	530,575.86	5.76%	30,561.17	10.19%	54,065.68	-4.17%	(22,125.01)	0.00%	0.00	6.02%	31,940.67	1,379.50
396.20	Power Operated Equipment	6,142,234.08	0.00%	0.00	31.72%	1,948,316.65	-30.77%	(1,889,965.43)	0.00%	0.00	0.95%	58,351.22	58,351.22
	TOTAL Account 396	6,672,809.94	0.46%	30,561.17	30.01%	2,002,382.33	-28.65%	(1,912,090.44)	0.00%	0.00	1.35%	90,291.89	59,730.72
	COMMUNICATION EQUIPMENT												
397.10	Radio Communication Equip. (Fixed)	226,847.00	7.37%	16,718.62	6.07%	13,763.90	0.00%	0.00	0.00%	0.00	6.07%	13,763.90	(2,954.72)
397.20	Radio Communication Equip. (Mobile)	468,875.34	7.34%	34,415.45	4.06%	19,052.43	0.00%	0.00	0.00%	0.00	4.06%	19,052.43	(15,363.02)
397.30	General Telephone Communication Eq	56,947.69	9.88%	5,626.43	10.69%	6,089.15	0.00%	0.00	0.00%	0.00	10.69%	6,089.15	462.72
397.80	Network Equipment	172,146.81	26.26%	45,205.75	17.68%	30,435.15	0.00%	0.00	0.00%	0.00	17.68%	30,435.15	(14,770.60)
	TOTAL Account 397	924,816.84	11.03%	101,966.25	7.50%	69,340.63	0.00%	0.00	0.00%	0.00	7.50%	69,340.63	(32,625.62)
398.00	Miscellaneous Equipment	56,850.20	1.27%	722.00	9.43%	5,361.40	0.00%	0.00	0.00%	0.00	9.43%	5,361.40	4,639.40
	Sub-Total (General Plant) Amortization	**5,179,502.08**		**525,686.49**	**6.98%**	**361,279.88**	**0.00%**	**0.00**	**0.00%**	**0.00**	**6.98%**	**361,279.88**	**(164,406.61)**
	TOTAL General Plant	26,859,761.20	9.85%	2,645,393.38	9.65%	2,593,009.70	-7.17%	(1,925,065.76)	0.09%	23,924.71	2.58%	691,868.66	(1,953,524.72)
	TOTAL Depreciable Plant	251,825,093.87	3.85%	9,698,264.31	3.09%	7,775,754.25	-0.77%	(1,942,570.49)	1.74%	4,390,873.75	4.06%	10,224,057.51	525,793.20
	NON-DEPRECIABLE PLANT												
374.1	Land (Distribution)	138,261.79											
389	Land & Land Rights (General)	1,328,891.91											
	Total Land	1,467,153.70											
	INTANGIBLE PLANT												
303	Miscellaneous Intangible Plant	3,949,065.10											
	Total Intangible Plant	3,949,065.10											
	TOTAL Non-Depreciable Plant	5,416,218.80											
	TOTAL Plant in Service	257,241,312.67											

Montana-Dakota Utilities Company
Gas Division

Summary of Book Depreciation Reserve by Recovery Component as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Total Book Depr Reserve 12/31/08 (g)	Cost of Removal In Book Res. (h)	Gross Salvage In Book Res. (i)	Plant Only Depr Reserve 12/31/08 (j)
	DEPRECIABLE PLANT					
	Distribution Plant					
374.20	Rights of Way	322,677.60	67,017.62	0.00	0.00	67,017.62
375.00	Distr. Meas & Reg Station Structures	609,311.11	356,503.11	88,819.63	(35,226.21)	302,909.69
	Mains					
376.10	Mains-Steel	41,975,049.45	36,466,142.85	11,014,795.39	643.84	25,450,703.62
376.20	Mains-Plastic	63,935,958.79	30,608,794.32	9,245,551.63	540.42	21,362,702.26
376.30	Mains-Valves	447,328.09	257,220.39	77,694.81	4.54	179,521.04
376.40	Mains-Manholes	69,919.29	55,146.20	16,657.21	0.97	38,488.02
376.50	Mains-Bridge & River Crossings	19,818.03	6,022.66	1,819.18	0.11	4,203.37
	Total Mains	106,448,073.65	67,393,326.41	20,356,518.22	1,189.88	47,035,618.31
378.00	Meas & Reg Station Equip-General	2,140,308.63	934,403.43	99,663.22	0.00	834,740.21
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	566,306.49	0.00	0.00	566,306.49
	Services					
380.10	Services-Steel	7,285,187.87	12,429,968.14	7,570,293.69	249.91	4,859,424.53
380.20	Services-Plastic	42,690,273.23	30,149,319.03	18,362,010.04	606.17	11,786,702.82
380.30	Farm & Fuel Lines	248,640.18	256,290.49	156,090.04	5.15	100,195.29
	Total Services	50,224,101.28	42,835,577.66	26,088,393.78	861.24	16,746,322.64
381.00	Meters	55,172,050.24	16,541,851.01	0.00	0.00	16,541,851.01
383.00	Service Regulators	5,555,207.98	2,508,676.39	0.00	0.00	2,508,676.39
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89	332,350.79	23,704.62	(71,113.80)	379,759.97
	MISCELLANEOUS EQUIPMENT					
386.10	Misc Property on Customers Premise	1,679.84	1,474.70	0.00	0.00	1,474.70
386.20	CNG Refueling station	261,880.34	259,586.77	0.00	0.00	259,586.77
386.30	CNG Lease/Demo	0.00	26,496.25	0.00	0.00	26,496.25
	TOTAL Account 386	263,560.18	287,557.72	0.00	0.00	287,557.72
	OTHER EQUIPMENT					
387.10	Cathodic Protection Equipment	1,737,817.71	1,180,475.15	0.00	0.00	1,180,475.15
387.20	Other Distribution Equipment	588,025.51	507,918.50	0.00	0.00	507,918.50
	TOTAL Account 387	2,325,843.22	1,688,393.65	0.00	0.00	1,688,393.65
	TOTAL Distribution Plant	224,965,332.67	133,511,964.28	46,657,099.47	(104,288.89)	86,959,153.70
	General Plant					
390.00	General Structures	5,835,295.28	1,988,707.89	53,975.67	47,546.19	1,887,186.03
	OFFICE FURNITURE & EQUIPMENT					
391.10	Office Furniture & Equipment	415,861.93	179,231.41	0.00	0.00	179,231.41
391.30	Computer Equipment - PC	828,118.21	823,565.05	0.00	0.00	823,565.05
391.50	Other Computer Equipment	53,696.84	8,767.81	0.00	0.00	8,767.81
	TOTAL Account 391	1,297,676.98	1,011,564.27	0.00	0.00	1,011,564.27

Montana-Dakota Utilities Company
Gas Division

Summary of Book Depreciation Reserve by Recovery Component as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Total Book Depr Reserve 12/31/08 (g)	Cost of Removal In Book Res. (h)	Gross Salvage In Book Res. (i)	Plant Only Depr Reserve 12/31/08 (j)
	TRANSPORTATION EQUIPMENT					
392.10	Transportation Equipment (Trailers)	397,059.69	122,493.27	0.00	0.00	122,493.27
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21	7,366,984.18	0.00	0.00	7,366,984.18
	TOTAL Account 392	9,172,153.90	7,489,477.45	0.00	0.00	7,489,477.45
393.00	Stores Equipment	148,282.28	88,443.55	0.00	0.00	88,443.55
	TOOLS, SHOP & GARAGE EQ.					
394.10	Tools, Shop & Garage Equip. (Non-Unitized	2,515,638.89	1,124,846.96	0.00	0.00	1,124,846.96
394.30	Vehicle Maintenance Equipment	37,100.02	23,917.83	0.00	0.00	23,917.83
394.40	Vehicle Refueling Equipment	26,852.90	16,795.80	0.00	0.00	16,795.80
	TOTAL Account 394	2,579,591.81	1,165,560.59	0.00	0.00	1,165,560.59
395.00	Laboratory Equipment	172,283.97	24,442.45	0.00	0.00	24,442.45
	POWER OPERATED EQUIPMENT					
396.10	Work Equipment (Trailers)	530,575.86	271,074.35	0.00	0.00	271,074.35
396.20	Power Operated Equipment	6,142,234.08	1,077,130.72	0.00	0.00	1,077,130.72
	TOTAL Account 396	6,672,809.94	1,348,205.07	0.00	0.00	1,348,205.07
	COMMUNICATION EQUIPMENT					
397.10	Radio Communication Equip. (Fixed)	226,847.00	117,179.40	0.00	0.00	117,179.40
397.20	Radio Communication Equip. (Mobile)	468,875.34	274,608.16	0.00	0.00	274,608.16
397.30	General Telephone Communication Equip.	56,947.69	24,756.98	0.00	0.00	24,756.98
397.80	Network Equipment	172,146.81	52,766.76	0.00	0.00	52,766.76
						0.00
	TOTAL Account 397	924,816.84	469,311.30	0.00	0.00	469,311.30
398.00	Miscellaneous Equipment	56,850.20	(5,285.64)	0.00	0.00	(5,285.64)
	Sub-Total (General Plant) Amortization	**5,179,502.08**	**2,754,036.52**	**0.00**	**0.00**	**2,754,036.52**
	TOTAL General Plant	26,859,761.20	13,580,426.93	53,975.67	47,546.19	13,478,905.07
	TOTAL Depreciable Plant	251,825,093.87	147,092,391.21	46,711,075.14	(56,742.70)	100,438,058.77
	NON-DEPRECIABLE PLANT					
374.1	Land (Distribution)	138,261.79	0.00			
389	Land & Land Rights (General)	1,328,891.91	0.00			
	Total Land	1,467,153.70	0.00			
	INTANGIBLE PLANT					
303	Miscellaneous Intangible Plant	3,949,065.10	503,426.57			
	Total Intangible Plant	3,949,065.10	503,426.57			
	TOTAL Non-Depreciable Plant	5,416,218.80	503,426.57			
	TOTAL Plant in Service	257,241,312.67	147,595,817.78			

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	322,677.60	0%	0.00	322,677.60	67,017.62	255,659.98	65-R3	57.2	4,469.58	1.39%
375.00	Distr. Meas & Reg Station Structures	609,311.11	0%	0.00	609,311.11	302,909.69	306,401.42	60-R3	33.0	9,284.89	1.52%
	Mains										
376.10	Mains-Steel	41,975,049.45	0%	0.00	41,975,049.45	25,450,703.62	16,524,345.83	47-R4	22.3	741,002.06	1.77%
376.20	Mains-Plastic	63,935,958.79	0%	0.00	63,935,958.79	21,362,702.26	42,573,256.53	47-R4	33.4	1,274,648.40	1.99%
376.30	Mains-Valves	447,328.09	0%	0.00	447,328.09	179,521.04	267,807.05	40-R2.5	26.1	10,260.81	2.29%
376.40	Mains-Manholes	69,919.29	0%	0.00	69,919.29	38,488.02	31,431.27	47-R4	24.6	1,277.69	1.83%
376.50	Mains-Bridge & River Crossings	19,818.03	0%	0.00	19,818.03	4,203.37	15,614.66	47-R4	38.3	407.69	2.06%
	Total Mains	106,448,073.65		0.00	106,448,073.65	47,035,618.31	59,412,455.34			2,027,596.65	1.90%
378.00	Meas & Reg Station Equip-General	2,140,308.63	0%	0.00	2,140,308.63	834,740.21	1,305,568.42	40-R2	27.5	47,475.22	2.22%
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	0%	0.00	1,028,821.89	566,306.49	462,515.40	27-L0	16.0	28,907.21	2.81%
	Services										
380.10	Services-Steel	7,285,187.87	0%	0.00	7,285,187.87	4,859,424.53	2,425,763.34	40-R3	13.4	181,027.11	2.48%
380.20	Services-Plastic	42,690,273.23	0%	0.00	42,690,273.23	11,786,702.82	30,903,570.41	40-R3	29.0	1,065,640.36	2.50%
380.30	Farm & Fuel Lines	248,640.18	0%	0.00	248,640.18	100,195.29	148,444.89	30-R1.5	17.9	8,293.01	3.34%
	Total Services	50,224,101.28		0.00	50,224,101.28	16,746,322.64	33,477,778.64			1,254,960.48	2.50%
381.00	Meters	55,172,050.24	0%	0.00	55,172,050.24	16,541,851.01	38,630,199.23	35-R4	24.1	1,602,912.83	2.91%
383.00	Service Regulators	5,555,207.98	0%	0.00	5,555,207.98	2,508,676.39	3,046,531.59	40-R2	25.4	119,942.19	2.16%
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89	0%	0.00	875,376.89	379,759.97	495,616.92	35-R2	23.3	21,271.11	2.43%
	MISCELLANEOUS EQUIPMENT										
386.10	Miscellaneous Property on Customers Premise	1,679.84	0%	0.00	1,679.84	1,474.70	205.14	15-R3	5.1	40.22	2.39%
386.20	CNG Refueling station	261,880.34	0%	0.00	261,880.34	259,586.77	2,293.57	15R-3	3.3	695.02	0.27%
386.30	CNG Lease/Demo	0.00	0%	0.00	0.00	26,496.25	-26,496.25	0	0.0	0.00	0.00%
	TOTAL Account 386	263,560.18		0.00	263,560.18	287,557.72	-23,997.54			735.24	0.28%
	OTHER EQUIPMENT										
387.10	Cathodic Protection Equipment	1,737,817.71	0%	0.00	1,737,817.71	1,180,475.15	557,342.56	20-R1.5	10.0	55,734.26	3.21%
387.20	Other Distribution Equipment	588,025.51	0%	0.00	588,025.51	507,918.50	80,107.01	25-R3	13.8	5,804.86	0.99%
	TOTAL Account 387	2,325,843.22		0.00	2,325,843.22	1,688,393.65	637,449.57			61,539.11	2.65%
	TOTAL Distribution Plant	224,965,332.67		0.00	224,965,332.67	86,959,153.70	138,006,178.97			5,179,094.52	2.30%
	General Plant										
390.00	General Structures	5,835,295.28	0%	0.00	5,835,295.28	1,887,186.03	3,948,109.25	31-R4	21.9	180,278.96	3.09%

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	OFFICE FURNITURE & EQUIPMENT										
391.10	Office Furniture & Equipment	415,861.93	0%	0.00	415,861.93	179,231.41	236,630.52	15-R1	N/A	27,412.62	6.59% *
391.30	Computer Equipment - PC	828,118.21	0%	0.00	828,118.21	823,565.05	4,553.16	5-R2	N/A	93,383.50	11.28% *
391.50	Other Computer Equipment	53,696.84	0%	0.00	53,696.84	8,767.81	44,929.03	5-R2	N/A	2,667.08	4.97% *
	TOTAL Account 391	1,297,676.98		0.00	1,297,676.98	1,011,564.27	286,112.71			123,463.20	9.51%
	TRANSPORTATION EQUIPMENT										
392.10	Transportation Equipment (Trailers)	397,059.69	0%	0.00	397,059.69	122,493.27	274,566.42	8-R0.5	5.6	49,029.72	12.35%
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21	0%	0.00	8,775,094.21	7,366,984.18	1,408,110.03	7-R3	3.5	0.00	0.00%
	TOTAL Account 392	9,172,153.90		0.00	9,172,153.90	7,489,477.45	1,682,676.45			49,029.72	0.53%
393.00	Stores Equipment	148,282.28	0%	0.00	148,282.28	88,443.55	59,838.73	35-R3	N/A	3,613.53	2.44% *
	TOOLS, SHOP & GARAGE EQ.										
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89	0%	0.00	2,515,638.89	1,124,846.96	1,390,791.93	18-R1.5	N/A	142,108.78	5.65% *
394.30	Vehicle Maintenance Equipment	37,100.02	0%	0.00	37,100.02	23,917.83	13,182.19	20-R3	N/A	2,640.27	7.12% *
394.40	Vehicle Refueling Equipment	26,852.90	0%	0.00	26,852.90	16,795.80	10,057.10	15-R3	N/A	2,772.05	10.32% *
	TOTAL Account 394	2,579,591.81		0.00	2,579,591.81	1,165,560.59	1,414,031.22			147,521.10	5.72%
395.00	Laboratory Equipment	172,283.97	0%	0.00	172,283.97	24,442.45	147,841.52	20-R2	N/A	11,980.02	6.95% *
	POWER OPERATED EQUIPMENT										
396.10	Work Equipment (Trailers)	530,575.86	0%	0.00	530,575.86	271,074.35	259,501.51	10-R2	4.8	54,062.81	10.19%
396.20	Power Operated Equipment	6,142,234.08	0%	0.00	6,142,234.08	1,077,130.72	5,065,103.36	4-L1	2.6	1,948,116.68	31.72%
	TOTAL Account 396	6,672,809.94		0.00	6,672,809.94	1,348,205.07	5,324,604.87			2,002,179.49	30.01%
	COMMUNICATION EQUIPMENT										
397.10	Radio Communication Equip. (Fixed)	226,847.00	0%	0.00	226,847.00	117,179.40	109,667.60	15-R3	N/A	13,763.90	6.07% *
397.20	Radio Communication Equip. (Mobile)	468,875.34	0%	0.00	468,875.34	274,608.16	194,267.18	15-R3	N/A	19,052.43	4.06% *
397.30	General Telephone Communication Equip.	56,947.69	0%	0.00	56,947.69	24,756.98	32,190.71	10-R1	N/A	6,089.15	10.69% *
397.80	Network Equipment	172,146.81	0%	0.00	172,146.81	52,766.76	119,380.05	5-R3	N/A	30,435.15	17.68% *
	TOTAL Account 397	924,816.84		0.00	924,816.84	469,311.30	455,505.54			69,340.63	7.50%
398.00	Miscellaneous Equipment	56,850.20	0%	0.00	56,850.20	(5,285.64)	62,135.84	20-R2	N/A	5,361.40	9.43% *
	Sub-Total (General Plant) Amortization	**5,179,502.08**		**0.00**	**5,179,502.08**	**2,754,036.52**	**2,425,465.56**			**361,279.89**	**6.98%**
	TOTAL General Plant	26,859,761.20		0.00	26,859,761.20	13,478,905.07	13,380,856.13			2,592,768.06	9.65%
	TOTAL Depreciable Plant	251,825,093.87		0.00	251,825,093.87	100,438,058.77	151,387,035.10			7,771,862.58	3.09%

Table 2 - Plant Only

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	NON-DEPRECIABLE PLANT										
374.1	Land (Distribution)	138,261.79									
389	Land & Land Rights (General)	1,328,891.91									
	Total Land	1,467,153.70									
	INTANGIBLE PLANT										
303	Miscellaneous Intangible Plant	3,949,065.10									
	Total Intangible Plant	3,949,065.10									
	TOTAL Non-Depreciable Plant	5,416,218.80									
	TOTAL Plant in Service	257,241,312.67									

* Used Proposed Study Amoritzation Rates.

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No.	Description	Original Cost 12/31/08	Estimated Future Net Salvage %	Estimated Future Net Salvage Amount	Original Cost Less Salvage	Book Depreciation Reserve	Net Original Cost Less Salvage	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Deprecation Rate
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	322,677.60	0%	0.00	322,677.60	0.00	0.00	65-R3	57.2	0.00	0.00%
375.00	Distr. Meas & Reg Station Structures	609,311.11	0%	0.00	609,311.11	(35,226.21)	35,226.21	60-R3	33.0	1,067.46	0.18%
	Mains										
376.10	Mains-Steel	41,975,049.45	0%	0.00	41,975,049.45	643.84	(643.84)	47-R4	22.3	(28.87)	0.00%
376.20	Mains-Plastic	63,935,958.79	0%	0.00	63,935,958.79	540.42	(540.42)	47-R4	33.4	(16.18)	0.00%
376.30	Mains-Valves	447,328.09	0%	0.00	447,328.09	4.54	(4.54)	40-R2.5	26.1	(0.17)	0.00%
376.40	Mains-Manholes	69,919.29	0%	0.00	69,919.29	0.97	(0.97)	47-R4	24.6	(0.04)	0.00%
376.50	Mains-Bridge & River Crossings	19,818.03	0%	0.00	19,818.03	0.11	(0.11)	47-R4	38.3	(0.00)	0.00%
	Total Mains	106,448,073.65		0.00	106,448,073.65	1,189.88	(1,189.88)			(45.27)	0.00%
378.00	Meas & Reg Station Equip-General	2,140,308.63	0%	0.00	2,140,308.63	0.00	0.00	40-R2	27.5	0.00	0.00%
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	0%	0.00	1,028,821.89	0.00	0.00	27-L0	16.0	0.00	0.00%
	Services										
380.10	Services-Steel	7,285,187.87	0%	0.00	7,285,187.87	249.91	(249.91)	40-R3	13.4	(18.65)	0.00%
380.20	Services-Plastic	42,690,273.23	0%	0.00	42,690,273.23	606.17	(606.17)	40-R3	29.0	(20.90)	0.00%
380.30	Farm & Fuel Lines	248,640.18	0%	0.00	248,640.18	5.15	(5.15)	30-R1.5	17.9	(0.29)	0.00%
	Total Services	50,224,101.28		0.00	50,224,101.28	861.24	(861.24)			(39.84)	0.00%
381.00	Meters	55,172,050.24	0%	0.00	55,172,050.24	0.00	0.00	35-R4	24.1	0.00	0.00%
383.00	Service Regulators	5,555,207.98	10%	555,520.80	4,999,687.18	0.00	(555,520.80)	40-R2	25.4	(21,870.90)	-0.39%
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89	0%	0.00	875,376.89	(71,113.80)	71,113.80	35-R2	23.3	3,052.09	0.35%
	MISCELLANEOUS EQUIPMENT										
386.10	Miscellaneous Property on Customers Prem	1,679.84	0%	0.00	1,679.84	0.00	0.00	15-R3	5.1	0.00	0.00%
386.20	CNG Refueling station	261,880.34	0%	0.00	261,880.34	0.00	0.00	15R-3	3.3	0.00	0.00%
386.30	CNG Lease/Demo	0.00	0%	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00%
	TOTAL Account 386	263,560.18		0.00	263,560.18	0.00	0.00			0.00	0.00%
	OTHER EQUIPMENT										
387.10	Cathodic Protection Equipment	1,737,817.71	0%	0.00	1,737,817.71	0.00	0.00	20-R1.5	10.0	0.00	0.00%
387.20	Other Distribution Equipment	588,025.51	0%	0.00	588,025.51	0.00	0.00	25-R3	13.8	0.00	0.00%
	TOTAL Account 387	2,325,843.22		0.00	2,325,843.22	0.00	0.00			0.00	0.00%
	TOTAL Distribution Plant	224,965,332.67		555,520.80	224,409,811.87	(104,288.89)	(451,231.91)			(17,836.45)	-0.01%

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	General Plant										
390.00	General Structures	5,835,295.28	0%	0.00	5,835,295.28	47,546.19	(47,546.19)	31-R4	21.9	(2,171.06)	-0.04%
	OFFICE FURNITURE & EQUIPMENT										
391.10	Office Furniture & Equipment	415,861.93	0%	0.00	415,861.93	0.00	0.00	15-R1	N/A	0.00	0.00% *
391.30	Computer Equipment - PC	828,118.21	0%	0.00	828,118.21	0.00	0.00	5-R2	N/A	0.00	0.00% *
391.50	Other Computer Equipment	53,696.84	0%	0.00	53,696.84	0.00	0.00	5-R2	N/A	0.00	0.00% *
	TOTAL Account 391	1,297,676.98		0.00	1,297,676.98	0.00	0.00			0.00	0.00%
	TRANSPORTATION EQUIPMENT										
392.10	Transportation Equipment (Trailers)	397,059.69	15%	59,558.95	337,500.74	0.00	(59,558.95)	8-R0.5	5.6	(10,635.53)	-2.68%
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21	20%	1,755,018.84	7,020,075.37	0.00	(1,755,018.84)	7-R3	3.5	0.00	0.00%
	TOTAL Account 392	9,172,153.90		1,814,577.79	7,357,576.11	0.00	(1,814,577.79)			(10,635.53)	-0.12%
393.00	Stores Equipment	148,282.28	0%	0.00	148,282.28	0.00	0.00	35-R3	N/A	0.00	0.00% *
	TOOLS, SHOP & GARAGE EQ.										
394.10	Tools, Shop & Garage Equip. (Non-Unitized	2,515,638.89	0%	0.00	2,515,638.89	0.00	0.00	18-R1.5	N/A	0.00	0.00% *
394.30	Vehicle Maintenance Equipment	37,100.02	0%	0.00	37,100.02	0.00	0.00	20-R3	N/A	0.00	0.00% *
394.40	Vehicle Refueling Equipment	26,852.90	0%	0.00	26,852.90	0.00	0.00	15-R3	N/A	0.00	0.00% *
	TOTAL Account 394	2,579,591.81		0.00	2,579,591.81	0.00	0.00			0.00	0.00%
395.00	Laboratory Equipment	172,283.97	0%	0.00	172,283.97	0.00	0.00	20-R2	N/A	0.00	0.00% *
	POWER OPERATED EQUIPMENT										
396.10	Work Equipment (Trailers)	530,575.86	20%	106,115.17	424,460.69	0.00	(106,115.17)	10-R2	4.8	(22,107.33)	-4.17%
396.20	Power Operated Equipment	6,142,234.08	80%	4,913,787.26	1,228,446.82	0.00	(4,913,787.26)	4-L1	2.6	(1,889,918.18)	-30.77%
	TOTAL Account 396	6,672,809.94		5,019,902.43	1,652,907.51	0.00	(5,019,902.43)			(1,912,025.50)	-28.65%
	COMMUNICATION EQUIPMENT										
397.10	Radio Communication Equip. (Fixed)	226,847.00	0%	0.00	226,847.00	0.00	0.00	15-R3	N/A	0.00	0.00% *
397.20	Radio Communication Equip. (Mobile)	468,875.34	0%	0.00	468,875.34	0.00	0.00	15-R3	N/A	0.00	0.00% *
397.30	General Telephone Communication Equip.	56,947.69	0%	0.00	56,947.69	0.00	0.00	10-R1	N/A	0.00	0.00% *
397.80	Network Equipment	172,146.81	0%	0.00	172,146.81	0.00	0.00	5-R3	N/A	0.00	0.00% *
	TOTAL Account 397	924,816.84		0.00	924,816.84	0.00	0.00			0.00	0.00%
398.00	Miscellaneous Equipment	56,850.20	0%	0.00	56,850.20	0.00	0.00	20-R2	N/A	0.00	0.00% *
	Sub-Total (General Plant) Amortization	**5,179,502.08**		**0.00**	**5,179,502.08**	**0.00**	**0.00**			**0.00**	**0.00%**
	TOTAL General Plant	26,859,761.20		6,834,480.22	20,025,280.98	47,546.19	(6,882,026.41)			(1,924,832.09)	-7.17%
	TOTAL Depreciable Plant	251,825,093.87		7,390,001.02	244,435,092.85	(56,742.70)	(7,333,258.32)			(1,942,668.54)	-0.77%

Table 2 - Gross Salvage

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	NON-DEPRECIABLE PLANT										
374.1	Land (Distribution)	138,261.79									
389	Land & Land Rights (General)	1,328,891.91									
	Total Land	1,467,153.70									
	INTANGIBLE PLANT										
303	Miscellaneous Intangible Plant	3,949,065.10									
	Total Intangible Plant	3,949,065.10									
	TOTAL Non-Depreciable Plant	5,416,218.80									
	TOTAL Plant in Service	257,241,312.67									

* Used Proposed Study Amoritzation Rates.

Table 2 - COR

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	Distribution Plant										
374.20	Rights of Way	322,677.60	0%	0.00	322,677.60	0.00	0.00	65-R3	57.2	0.00	0.00%
375.00	Distr. Meas & Reg Station Structures	609,311.11	-50%	(304,655.56)	913,966.67	88,819.63	215,835.93	60-R3	33.0	6,540.48	1.07%
	Mains										
376.10	Mains-Steel	41,975,049.45	-50%	(20,987,524.73)	62,962,574.18	11,014,795.39	9,972,729.34	47-R4	22.3	447,207.59	1.07%
376.20	Mains-Plastic	63,935,958.79	-50%	(31,967,979.40)	95,903,938.19	9,245,551.63	22,722,427.77	47-R4	33.4	680,312.21	1.06%
376.30	Mains-Valves	447,328.09	-50%	(223,664.05)	670,992.14	77,694.81	145,969.24	40-R2.5	26.1	5,592.69	1.25%
376.40	Mains-Manholes	69,919.29	-50%	(34,959.65)	104,878.94	16,657.21	18,302.44	47-R4	24.6	744.00	1.06%
376.50	Mains-Bridge & River Crossings	19,818.03	-50%	(9,909.02)	29,727.05	1,819.18	8,089.84	47-R4	38.3	211.22	1.07%
	Total Mains	106,448,073.65		(53,224,036.85)	159,672,110.50	20,356,518.22	32,867,518.63			1,134,067.72	1.07%
378.00	Meas & Reg Station Equip-General	2,140,308.63	-30%	(642,092.59)	2,782,401.22	99,663.22	542,429.37	40-R2	27.5	19,724.70	0.92%
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	-15%	(154,323.28)	1,183,145.17	0.00	154,323.28	27-L0	16.0	9,645.21	0.94%
	Services										
380.10	Services-Steel	7,285,187.87	-200%	(14,570,375.74)	21,855,563.61	7,570,293.69	7,000,082.05	40-R3	13.4	522,394.18	7.17%
380.20	Services-Plastic	42,690,273.23	-200%	(85,380,546.46)	128,070,819.69	18,362,010.04	67,018,536.42	40-R3	29.0	2,310,984.01	5.41%
380.30	Farm & Fuel Lines	248,640.18	-200%	(497,280.36)	745,920.54	156,090.04	341,190.32	30-R1.5	17.9	19,060.91	7.67%
	Total Services	50,224,101.28		(100,448,202.56)	150,672,303.84	26,088,393.78	74,359,808.78			2,852,439.11	5.68%
381.00	Meters	55,172,050.24	-15%	(8,275,807.54)	63,447,857.78	0.00	8,275,807.54	35-R4	24.1	343,394.50	0.62%
383.00	Service Regulators	5,555,207.98	0%	0.00	5,555,207.98	0.00	0.00	40-R2	25.4	0.00	0.00%
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89	-15%	(131,306.53)	1,006,683.42	23,704.62	107,601.91	35-R2	23.3	4,618.11	0.53%
	MISCELLANEOUS EQUIPMENT										
386.10	Miscellaneous Property on Customers Premise	1,679.84	0%	0.00	1,679.84	0.00	0.00	15-R3	5.1	0.00	0.00%
386.20	CNG Refueling station	261,880.34	0%	0.00	261,880.34	0.00	0.00	15R-3	3.3	0.00	0.00%
386.30	CNG Lease/Demo	0.00	0%	0.00	0.00	0.00	0.00		0.0	0.00	0.00%
	TOTAL Account 386	263,560.18		0.00	263,560.18	0.00	0.00			0.00	0.00%
	OTHER EQUIPMENT										
387.10	Cathodic Protection Equipment	1,737,817.71	0%	0.00	1,737,817.71	0.00	0.00	20-R1.5	10.0	0.00	0.00%
387.20	Other Distribution Equipment	588,025.51	0%	0.00	588,025.51	0.00	0.00	25-R3	13.8	0.00	0.00%
	TOTAL Account 387	2,325,843.22		0.00	2,325,843.22	0.00	0.00			0.00	0.00%
	TOTAL Distribution Plant	224,965,332.67		(163,180,424.91)	388,145,757.58	46,657,099.47	116,523,325.44			4,370,429.83	1.94%
	General Plant										
390.00	General Structures	5,835,295.28	-10%	(583,529.53)	6,418,824.81	53,975.67	529,553.86	31-R4	21.9	24,180.54	0.41%

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	OFFICE FURNITURE & EQUIPMENT										
391.10	Office Furniture & Equipment	415,861.93	0%	0.00	415,861.93	0.00	0.00	15-R1	N/A	0.00	0.00%
391.30	Computer Equipment - PC	828,118.21	0%	0.00	828,118.21	0.00	0.00	5-R2	N/A	0.00	0.00%
391.50	Other Computer Equipment	53,696.84	0%	0.00	53,696.84	0.00	0.00	5-R2	N/A	0.00	0.00%
	TOTAL Account 391	1,297,676.98		0.00	1,297,676.98	0.00	0.00			0.00	0.00%
	TRANSPORTATION EQUIPMENT										
392.10	Transportation Equipment (Trailers)	397,059.69	0%	0.00	397,059.69	0.00	0.00	8-R0.5	5.6	0.00	0.00%
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21	0%	0.00	8,775,094.21	0.00	0.00	7-R3	3.5	0.00	0.00%
	TOTAL Account 392	9,172,153.90		0.00	9,172,153.90	0.00	0.00			0.00	0.00%
393.00	Stores Equipment	148,282.28	0%	0.00	148,282.28	0.00	0.00	35-R3	N/A	0.00	0.00%
	TOOLS, SHOP & GARAGE EQ.										
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89	0%	0.00	2,515,638.89	0.00	0.00	18-R1.5	N/A	0.00	0.00%
394.30	Vehicle Maintenance Equipment	37,100.02	0%	0.00	37,100.02	0.00	0.00	20-R3	N/A	0.00	0.00%
394.40	Vehicle Refueling Equipment	26,852.90	0%	0.00	26,852.90	0.00	0.00	15-R3	N/A	0.00	0.00%
	TOTAL Account 394	2,579,591.81		0.00	2,727,874.09	0.00	0.00			0.00	0.00%
395.00	Laboratory Equipment	172,283.97	0%	0.00	172,283.97	0.00	0.00	20-R2	N/A	0.00	0.00%
	POWER OPERATED EQUIPMENT										
396.10	Work Equipment (Trailers)	530,575.86	0%	0.00	530,575.86	0.00	0.00	10-R2	4.8	0.00	0.00%
396.20	Power Operated Equipment	6,142,234.08	0%	0.00	6,142,234.08	0.00	0.00	4-L1	2.6	0.00	0.00%
	TOTAL Account 396	6,672,809.94		0.00	6,672,809.94	0.00	0.00			0.00	0.00%
	COMMUNICATION EQUIPMENT										
397.10	Radio Communication Equip. (Fixed)	226,847.00	0%	0.00	226,847.00	0.00	0.00	15-R3	N/A	0.00	0.00%
397.20	Radio Communication Equip. (Mobile)	468,875.34	0%	0.00	468,875.34	0.00	0.00	15-R3	N/A	0.00	0.00%
397.30	General Telephone Communication Equip.	56,947.69	0%	0.00	56,947.69	0.00	0.00	10-R1	N/A	0.00	0.00%
397.80	Network Equipment	172,146.81	0%	0.00	172,146.81	0.00	0.00	5-R3	N/A	0.00	0.00%
	TOTAL Account 397	924,816.84		0.00	924,816.84	0.00	0.00			0.00	0.00%
398.00	Miscellaneous Equipment	56,850.20	0%	0.00	56,850.20	0.00	0.00	20-R2	N/A	0.00	0.00%
	Sub-Total (General Plant) Amortization	**5,179,502.08**		**0.00**	**5,327,784.36**	**0.00**	**0.00**			**0.00**	**0.00%**
	TOTAL General Plant	26,859,761.20		(583,529.53)	27,443,290.73	53,975.67	529,553.86			24,180.54	0.09%
	TOTAL Depreciable Plant	251,825,093.87		(163,763,954.44)	415,589,048.31	46,711,075.14	117,052,879.30			4,394,610.37	1.75%

Montana-Dakota Utilities Company
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	NON-DEPRECIABLE PLANT										
374.1	Land (Distribution)	138,261.79									
389	Land & Land Rights (General)	1,328,891.91									
	Total Land	1,467,153.70									
	INTANGIBLE PLANT										
303	Miscellaneous Intangible Plant	3,949,065.10									
	Total Intangible Plant	3,949,065.10									
	TOTAL Non-Depreciable Plant	5,416,218.80									
	TOTAL Plant in Service	257,241,312.67									

Montana-Dakota Utilities Company
Gas Division

Original Cost Per Company Books, Adjustments, And
Original Cost Per Depreciation Study of December 31, 2008

Account No. (a)	Description (b)	Original Cost Per Co. Books 12/31/08 (c)	(Pending) Retirements (d)	Company Pending Adjustments (e)	Original Cost Per Depr Study Data 12/31/08 (e)
	DEPRECIABLE PLANT				
	Distribution Plant				
374.20	Rights of Way	322,677.60			322,677.60
375.00	Distr. Meas & Reg Station Structures	609,311.11			609,311.11
	Mains				
376.10	Mains-Steel	41,975,049.45			41,975,049.45
376.20	Mains-Plastic	63,935,958.79			63,935,958.79
376.30	Mains-Valves	447,328.09			447,328.09
376.40	Mains-Manholes	69,919.29			69,919.29
376.50	Mains-Bridge & River Crossings	19,818.03			19,818.03
	Total Mains	106,448,073.65	0.00	0.00	106,448,073.65
378.00	Meas & Reg Station Equip-General	2,140,308.63			2,140,308.63
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89			1,028,821.89
	Services				
380.10	Services-Steel	7,285,187.87			7,285,187.87
380.20	Services-Plastic	42,690,273.23			42,690,273.23
380.30	Farm & Fuel Lines	248,640.18			248,640.18
	Total Services	50,224,101.28	0.00	0.00	50,224,101.28
381.00	Meters	55,172,050.24			55,172,050.24
383.00	Service Regulators	5,555,207.98			5,555,207.98
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89			875,376.89
	MISCELLANEOUS EQUIPMENT				
386.10	Miscellaneous Property on Customers Premis	1,679.84			1,679.84
386.20	CNG Refueling station	261,880.34			261,880.34
386.30		0.00			0.00
	TOTAL Account 386	263,560.18	0.00	0.00	263,560.18
	OTHER EQUIPMENT				
387.10	Cathodic Protection Equipment	1,737,817.71			1,737,817.71
387.20	Other Distribution Equipment	588,025.51			588,025.51
	TOTAL Account 387	2,325,843.22	0.00	0.00	2,325,843.22
	TOTAL Distribution Plant	224,965,332.67	0.00	0.00	224,965,332.67
	General Plant				
390.00	General Structures	5,835,295.28			5,835,295.28
	OFFICE FURNITURE & EQUIPMENT				
391.10	Office Furniture & Equipment	415,861.93			415,861.93
391.30	Computer Equipment - PC	828,118.21			828,118.21
391.50	Other Computer Equipment	53,696.84			53,696.84
	TOTAL Account 391	1,297,676.98	0.00	0.00	1,297,676.98
	TRANSPORTATION EQUIPMENT				
392.10	Transportation Equipment (Trailers)	397,059.69			397,059.69
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21			8,775,094.21
	TOTAL Account 392	9,172,153.90	0.00	0.00	9,172,153.90
393.00	Stores Equipment	148,282.28			148,282.28

Montana-Dakota Utilities Company
Gas Division

Original Cost Per Company Books, Adjustments, And Original Cost Per Depreciation Study of December 31, 2008

Account No.	Description	Original Cost Per Co. Books 12/31/08	(Pending) Retirements	Company Pending Adjustments	Original Cost Per Depr Study Data 12/31/08
(a)	(b)	(c)	(d)	(e)	(e)
	TOOLS, SHOP & GARAGE EQ.				
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89			2,515,638.89
394.30	Vehicle Maintenance Equipment	37,100.02			37,100.02
394.40	Vehicle Refueling Equipment	26,852.90			26,852.90
	TOTAL Account 394	2,579,591.81	-	-	2,579,591.81
395.00	Laboratory Equipment	172,283.97			172,283.97
	POWER OPERATED EQUIPMENT				
396.10	Work Equipment (Trailers)	530,575.86			530,575.86
396.20	Power Operated Equipment	6,142,234.08			6,142,234.08
	TOTAL Account 396	6,672,809.94	0.00	0.00	6,672,809.94
	COMMUNICATION EQUIPMENT				
397.10	Radio Communication Equip. (Fixed)	226,847.00			226,847.00
397.20	Radio Communication Equip. (Mobile)	468,875.34			468,875.34
397.30	General Telephone Communication Equip.	56,947.69			56,947.69
397.80	Network Equipment	172,146.81			172,146.81
	TOTAL Account 397	924,816.84	0.00	0.00	924,816.84
398.00	Miscellaneous Equipment	56,850.20			56,850.20
	Sub-Total (General Plant) Amortization	**5,179,502.08**	**0.00**	**0.00**	**5,179,502.08**
	TOTAL General Plant	26,859,761.20	0.00	0.00	26,859,761.20
	TOTAL Depreciable Plant	251,825,093.87	0.00	0.00	251,825,093.87
	NON-DEPRECIABLE PLANT				
374.10	Land (Distribution)	$138,261.79			138,261.79
389.00	Land & Land Rights (General)	$1,328,891.91			1,328,891.91
	Total Land	1,467,153.70	0.00	0.00	1,467,153.70
	INTANGIBLE PLANT				
303.00	Miscellaneous Intangible Plant	$3,949,065.10			3,949,065.10
	Total Intangible Plant	3,949,065.10	0.00	0.00	3,949,065.10
	TOTAL Non-Depreciable Plant	5,416,218.80	0.00	0.00	5,416,218.80
	TOTAL Plant in Service	257,241,312.67	0.00	0.00	257,241,312.67
388.00	ARO	115,629.38			
	Total Including ARO	257,356,942.05			

Montana-Dakota Utilities Company
Gas Division

Summary of Book Depreciation Reserves Relative To Original Cost of Utility Plant in Service, Adjustments, And Depreciation Reserves Per Depreciation Study as of December 31, 2008

Account No.	Description	Depr Reserve Per Books 12/31/08	(Pending) Retirements	Depr Reserve Per Depr Study 12/31/08
	(b)	(c)	(d)	(e)
	DEPRECIABLE PLANT			
	Distribution Plant			
374.20	Rights of Way	67,017.62		67,017.62
375.00	Distr. Meas & Reg Station Structures	356,503.11		356,503.11
	Mains			
376.10	Mains-Steel	67,393,326.41		36,466,142.85
376.20	Mains-Plastic	0.00		30,608,794.32
376.30	Mains-Valves	0.00		257,220.39
376.40	Mains-Manholes	0.00		55,146.20
376.50	Mains-Bridge & River Crossings	0.00		6,022.66
	Total Mains	67,393,326.41	0.00	67,393,326.41
378.00	Meas & Reg Station Equip-General	934,403.43		934,403.43
379.00	Meas & Reg Station Equip-City Gate	566,306.49		566,306.49
	Services			
380.10	Services-Steel	42,835,577.66		12,429,968.14
380.20	Services-Plastic	0.00		30,149,319.03
380.30	Farm & Fuel Lines	0.00		256,290.49
	Total Services	42,835,577.66	0.00	42,835,577.66
381.00	Meters	16,541,851.01		16,541,851.01
383.00	Service Regulators	2,508,676.39		2,508,676.39
385.00	Industrial Meas. & Reg. Station Equipment	332,350.79		332,350.79
	MISCELLANEOUS EQUIPMENT			
386.10	Miscellaneous Property on Customers Premise	1,474.70		1,474.70
386.20	CNG Refueling station	259,586.77		259,586.77
386.30	CNG Lease/Demo	26,496.25		26,496.25
	TOTAL Account 386	287,557.72	0.00	287,557.72
	OTHER EQUIPMENT			
387.10	Cathodic Protection Equipment	1,180,475.15		1,180,475.15
387.20	Other Distribution Equipment	507,918.50		507,918.50
	TOTAL Account 387	1,688,393.65	0.00	1,688,393.65
	TOTAL Distribution Plant	133,511,964.28	0.00	133,511,964.28
	General Plant			
390.00	General Structures	1,988,707.89		1,988,707.89
	OFFICE FURNITURE & EQUIPMENT			
391.10	Office Furniture & Equipment	179,231.41		179,231.41
391.30	Computer Equipment - PC	823,565.05		823,565.05
391.50	Other Computer Equipment	8,767.81		8,767.81
	TOTAL Account 391	1,002,796.46	0.00	1,002,796.46
	TRANSPORTATION EQUIPMENT			
392.10	Transportation Equipment (Trailers)	122,493.27		122,493.27
392.20	Transportation Equipment (Cars & Trucks)	7,366,984.18		7,366,984.18
	TOTAL Account 392	7,489,477.45	0.00	7,489,477.45
393.00	Stores Equipment	88,443.55		88,443.55

Montana-Dakota Utilities Company
Gas Division

Summary of Book Depreciation Reserves Relative To Original Cost of Utility Plant in Service, Adjustments, And Depreciation Reserves Per Depreciation Study as of December 31, 2008

Account No.	Description (b)	Depr Reserve Per Books 12/31/08 (c)	(Pending) Retirements (d)	Depr Reserve Per Depr Study 12/31/08 (e)
	TOOLS, SHOP & GARAGE EQ.			
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	1,124,846.96		1,124,846.96
394.30	Vehicle Maintenance Equipment	23,917.83		23,917.83
394.40	Vehicle Refueling Equipment	16,795.80		16,795.80
	TOTAL Account 394	1,165,560.59	0.00	1,165,560.59
395.00	Laboratory Equipment	24,442.45		24,442.45
	POWER OPERATED EQUIPMENT			
396.10	Work Equipment (Trailers)	271,074.35		271,074.35
396.20	Power Operated Equipment	1,077,130.72		1,077,130.72
	TOTAL Account 396	1,348,205.07	0.00	1,348,205.07
	COMMUNICATION EQUIPMENT			
397.10	Radio Communication Equip. (Fixed)	117,179.40		117,179.40
397.20	Radio Communication Equip. (Mobile)	274,608.16		274,608.16
397.30	General Telephone Communication Equip.	24,756.98		24,756.98
397.80	Network Equipment	52,766.76		52,766.76
		-		
	TOTAL Account 397	469,311.30	0.00	469,311.30
398.00	Miscellaneous Equipment	(5,285.64)		(5,285.64)
	Sub-Total (General Plant) Amortization	**2,754,036.52**		**2,754,036.52**
	TOTAL General Plant	13,580,426.93	0.00	13,580,426.93
	TOTAL Depreciable Plant	147,092,391.21	0.00	147,092,391.21
	NON-DEPRECIABLE PLANT			
374.10	Land (Distribution)	0.00		0.00
389.00	Land & Land Rights (General)	0.00		0.00
	Total Land	0.00		0.00
	INTANGIBLE PLANT			
303.00	Miscellaneous Intangible Plant	503,426.57		503,426.57
	Total Intangible Plant	503,426.57		503,426.57
	TOTAL Non-Depreciable Plant	503,426.57	0.00	503,426.57
	TOTAL Plant in Service	147,595,817.78	0.00	147,595,817.78
388.00	ARO	59,099.88		
	Total Including ARO	147,654,917.66		

Montana-Dakota Utilities Company
Gas Division

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

Account No.	Description	Original Cost 12/31/08	Present: Net Salvage W/ COR %	Present: Net Salvage W/O COR %	Present: Gross COR %	Present: A.S.L./ Survivor Curve	Present: Present Depr Rate-%	Present: Average Remaining Life	Proposed: Net Salvage W/ COR %	Proposed: Net Salvage W/O COR %	Proposed: Gross COR %	Proposed: A.S.L./ Survivor Curve	Proposed: Average Remaining Life
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(o)	(p)
	DEPRECIABLE PLANT												
	Distribution Plant												
374.20	Rights of Way	322,677.60	0.0%	0%	0%	65-R2.5	0.75%	49.3	0%	0%	0%	65-R3	57.2
375.00	Distr. Meas & Reg Station Structures	609,311.11	-50.0%	0%	-50%	55-R2.5	2.57%	29.9	-50%	0%	-50%	60-R3	33.0
	Mains												
376.10	Mains-Steel	41,975,049.45	-60.0%	0%	-60%	45-R3	1.92%	21.4	-50%	0%	-50%	47-R4	22.3
376.20	Mains-Plastic	63,935,958.79	-60.0%	0%	-60%	45-R3	1.92%	33.7	-50%	0%	-50%	47-R4	33.4
376.30	Mains-Valves	447,328.09	-60.0%	0%	-60%	40-R2.5	1.92%	30.4	-50%	0%	-50%	40-R2.5	26.1
376.40	Mains-Manholes	69,919.29	-60.0%	0%	-60%	45-R3	1.92%	29.9	-50%	0%	-50%	47-R4	24.6
376.50	Mains-Bridge & River Crossings	19,818.03	-60.0%	0%	-60%	45-R3	1.92%	3.1	-50%	0%	-50%	47-R4	38.3
	Total Mains	106,448,073.65											
378.00	Meas & Reg Station Equip-General	2,140,308.63	-30.0%	0%	-30%	40-R1	2.96%	23.3	-30%	0%	-30%	40-R2	27.5
379.00	Meas & Reg Station Equip-City Gate	1,028,821.89	-15.0%	0%	-15%	35-R2.5	3.54%	18.9	-15%	0%	-15%	27-L0	16.0
	Services												
380.10	Services-Steel	7,285,187.87	-175.0%	0%	-175%	40-R2.5	5.66%	18.8	-200%	0%	-200%	40-R3	13.4
380.20	Services-Plastic	42,690,273.23	-175.0%	0%	-175%	40-R3	5.66%	29.0	-200%	0%	-200%	40-R3	29.0
380.30	Farm & Fuel Lines	248,640.18	-175.0%	0%	-175%	30-R1.5	5.66%	20.6	-200%	0%	-200%	30-R1.5	17.9
	Total Services	50,224,101.28											
381.00	Meters	55,172,050.24	0.0%	0%	0%	35-R2.5	3.19%	19.9	-15%	0%	-15%	35-R4	24.1
383.00	House Regulators	5,555,207.98	10.0%	10%	0%	35-R3	2.59%	18.0	10%	10%	0%	40-R2	25.4
385.00	Industrial Meas. & Reg. Station Equipment	875,376.89	-15.0%	0%	-15%	35-R2	3.04%	20.6	-15%	0%	-15%	35-R2	23.3
	MISCELLANEOUS EQUIPMENT												
386.10	Miscellaneous Property on Customers Premise	1,679.84	0.0%	0%	0%	15-R3	5.19%	10.7	0%	0%	0%	15-R3	5.1
386.20	CNG Refueling station	261,880.34	0.0%	0%	0%	15R-3	3.70%	8.1	0%	0%	0%	15R-3	3.3
386.30	CNG Lease/Demo	0.00											
	TOTAL Account 386	263,560.18											
	OTHER EQUIPMENT												
387.10	Cathodic Protection Equipment	1,737,817.71	0.0%	0%	0%	20-R1.5	5.75%	10.1	0%	0%	0%	20-R1.5	10.0
387.20	Other Distribution Equipment	588,025.51	0.0%	0%	0%	25-R3	1.42%	17.8	0%	0%	0%	25-R3	13.8
	TOTAL Account 387	2,325,843.22											
	TOTAL Distribution Plant	224,965,332.67											

Montana-Dakota Utilities Company
Gas Division

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

Account No.	Description	Original Cost 12/31/08	Present Parameters: Net Salvage W/ COR %	Net Salvage W/O COR %	Gross COR %	A.S.L./ Survivor Curve	Present Depr Rate-%	Average Remaining Life	Proposed Parameters: Net Salvage W/ COR %	Net Salvage W/O COR %	Gross COR %	A.S.L./ Survivor Curve	Average Remaining Life
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(o)	(p)
	General Plant												
390.00	General Structures	5,835,295.28	-10.0%	0%	-10%	35-R3	3.73%	11.3	-10%	0%	-10%	31-R4	21.9
	OFFICE FURNITURE & EQUIPMENT												
391.10	Office Furniture & Equipment	415,861.93	5.0%	5%	0% (2)	15	4.97%	N/A	0%	0%	0%	15-R1	N/A
391.30	Computer Equipment - PC	828,118.21	0.0%	0%	0%	5-R2	26.02%	2.4	0%	0%	0%	5-R2	N/A
391.50	Other Computer Equipment	53,696.84				N/A	0.0	N/A	0%	0%	0%	5-R2	N/A
	TOTAL Account 391	1,297,676.98											
	TRANSPORTATION EQUIPMENT												
392.10	Transportation Equipment (Trailers)	397,059.69	15.0%	15%	0%	8-R3	4.36%	5.3	15%	15%	0%	8-R0.5	5.6
392.20	Transportation Equipment (Cars & Trucks)	8,775,094.21	15.0%	15%	0%	6-R3	21.13%	2.3	20%	20%	0%	7-R3	3.5
	TOTAL Account 392	9,172,153.90											
393.00	Stores Equipment	148,282.28	0.0%	0%	0% (2)	35	2.49%	N/A	0%	0%	0%	35-R3	N/A
	TOOLS, SHOP & GARAGE EQ.												
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89	10.0%	10%	0% (2)	18	6.62%	N/A	0%	0%	0%	18-R1.5	N/A
394.30	Vehicle Maintenance Equipment	37,100.02	0.0%	0%	0% (2)	20	5.78%	N/A	0%	0%	0%	20-R3	N/A
394.40	Vehicle Refueling Equipment	26,852.90	0.0%	0%	0% (2)	15	4.72%	N/A	0%	0%	0%	15-R3	N/A
	TOTAL Account 394	2,579,591.81											
395.00	Laboratory Equipment	172,283.97	0.0%	0%	0% (2)	20	7.67%	N/A	0%	0%	0%	20-R2	N/A
	POWER OPERATED EQUIPMENT												
396.10	Work Equipment (Trailers)	530,575.86	35.0%	35%	0%	10-R2	5.76%	5.9	20%	20%	0%	10-R2	4.8
396.20	Power Operated Equipment	6,142,234.08	60.0%	60%	0%	7-R2	0.00%	3.2	80%	80%	0%	4-L1	2.6
	TOTAL Account 396	6,672,809.94											
	COMMUNICATION EQUIPMENT												
397.10	Radio Communication Equip. (Fixed)	226,847.00	0.0%	0%	0% (2)	15	7.37%	N/A	0%	0%	0%	15-R3	N/A
397.20	Radio Communication Equip. (Mobile)	468,875.34	0.0%	0%	0% (2)	15	7.34%	N/A	0%	0%	0%	15-R3	N/A
397.30	General Telephone Communication Equip.	56,947.69	0.0%	0%	0% (2)	10	9.88%	N/A	0%	0%	0%	10-R1	N/A
397.80	Network Equipment	172,146.81	0.0%	0%	0% (2)	5	26.26%	N/A	0%	0%	0%	5-R3	N/A
	TOTAL Account 397	924,816.84											

Table 5

Montana-Dakota Utilities 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		Gross	A.S.L./	Present	Average	Net Salvage		Gross	A.S.L./	Average
Account No.	Description	Cost 12/31/08	W/ COR %	W/O COR %	COR %	Survivor Curve	Depr Rate-%	Remaining Life	W/ COR %	W/O COR %	COR %	Survivor Curve	Remaining Life
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(o)	(p)
398.00	Miscellaneous Equipment	56,850.20	0.0%	0%	0% (2)	20	1.27%	N/A	0%	0%	0%	20-R2	N/A
	Sub-Total (General Plant) Amortization	**5,179,502.08**											
	TOTAL General Plant	26,859,761.20											
	TOTAL Depreciable Plant	251,825,093.87											
	NON-DEPRECIABLE PLANT												
374.1	Land (Distribution)	138,261.79											
389	Land & Land Rights (General)	1,328,891.91											
	Total Land	1,467,153.70											
	INTANGIBLE PLANT												
303	Miscellaneous Intangible Plant	3,949,065.10											
	Total Intangible Plant	3,949,065.10											
	TOTAL Non-Depreciable Plant	5,416,218.80											
	TOTAL Plant in Service	257,241,312.67											

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.
(2) General Plant Amortization

Montana-Dakota Utilities Company
Gas Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation/Amortization Expense
Under Present Rates and Proposed Amortization

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Present Rates Rate % (d)	Present Rates Annual Accrual (e)	Proposed Amortization Rate % (f)	Proposed Amortization Annual Accrual (g)	Net Change Depr/Amort Expense (h)
	DEPRECIABLE PLANT						
	General Plant						
	GENERAL STRUCTURES						
	OFFICE FURNITURE & EQUIPMENT						
391.10	Office Furniture & Equipment	415,861.93	4.97%	20,668.34	6.59%	27,412.62	6,744.28
391.30	Computer Equipment - PC	828,118.21	26.02%	215,476.36	11.28%	93,383.50	-122,092.86
391.50	Other Computer Equipment	53,696.84	0.00%	0.00	4.97%	2,667.08	2,667.08
	TOTAL Account 391.10, 391.30 &391.5	1,297,676.98	18.20%	236,144.70	9.51%	123,463.20	-112,681.50
393.00	Stores Equipment	148,282.28	2.49%	3,692.23	2.44%	3,613.53	-78.70
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	2,515,638.89	6.62%	166,535.29	5.65%	142,108.78	-24,426.51
394.30	Vehicle Maintainence Equipment	37,100.02	5.78%	2,144.38	7.12%	2,640.27	495.89
394.40	Vehicle Refueling Equipment	26,852.90	4.72%	1,267.46	10.32%	2,772.05	1,504.59
	TOTAL Account 394	2,579,591.81	6.59%	169,947.13	5.72%	147,521.10	-22,426.03
395.00	Laboratory Equipment	172,283.97	7.67%	13,214.18	6.95%	11,980.02	-1,234.16
	COMMUNICATION EQUIPMENT						
397.10	Radio Communication Equip. (Fixed)	226,847.00	7.37%	16,718.62	6.07%	13,763.90	-2,954.72
397.20	Radio Communication Equip. (Mobile)	468,875.34	7.34%	34,415.45	4.06%	19,052.43	-15,363.02
397.30	General Telephone Communication Equip.	56,947.69	9.88%	5,626.43	10.69%	6,089.15	462.72
397.80	Network Equipment	172,146.81	26.26%	45,205.75	17.68%	30,435.15	-14,770.60
	TOTAL Account 397	924,816.84	11.03%	101,966.25	7.50%	69,340.63	-32,625.62
398.00	Miscellaneous Equipment	56,850.20	1.27%	722.00	9.43%	5,361.40	4,639.40
	Sub-Total (General Plant) Amortization	**5,179,502.08**	**10.15%**	**525,686.49**	**6.98%**	**361,279.88**	**-164,406.61**

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 391.10 - Office Furniture & Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15 R1
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1981	0.00	0	(1)	0.00	0.00	0	0.00
1982	0.00	0	(1)	0.00	0.00	0	0.00
1983	7,307.73	6,569	(1)	7,307.73	0.00	0	0.00
1984	16,479.54	14,486	(1)	16,479.54	0.00	0	0.00
1985	10,979.03	9,421	(1)	10,979.03	0.00	0	0.00
1986	4,822.91	4,033	(1)	4,822.91	0.00	0	0.00
1987	4,502.87	3,661	(1)	4,502.87	0.00	0	0.00
1988	4,948.78	3,903	(1)	4,948.78	0.00	0	0.00
1989	3,828.83	2,923	(1)	3,828.83	0.00	0	0.00
1990	2,689.60	1,981	(1)	2,689.60	0.00	0	0.00
1991	34,433.72	24,398	(1)	34,433.72	0.00	0	0.00
1992	1,536.78	1,044	(1)	1,536.78	0.00	0	0.00
1993	10,058.25	6,520	(1)	10,058.25	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	8,216.74	4,783	(2)	4,783.00	3,433.74	2	1,716.87
1996	12,579.64	6,877	(2)	6,877.00	5,702.64	3	1,900.88
1997	2,820.08	1,437	(2)	1,437.00	1,383.08	4	345.77
1998	2,737.78	1,290	(2)	1,290.00	1,447.78	5	289.56
1999	5,933.10	2,558	(2)	2,558.00	3,375.10	6	562.52
2000	8,854.29	3,452	(2)	3,452.00	5,402.29	7	771.76
2001	449.66	156	(2)	156.00	293.66	8	36.71
2002	211,189.90	64,097	(2)	64,097.00	147,092.90	9	16,343.66
2003	18,121.04	4,692	(2)	4,692.00	13,429.04	10	1,342.90
2004	5,956.62	1,272	(2)	1,272.00	4,684.62	11	425.87
2005	10,911.21	1,828	(2)	1,828.00	9,083.21	12	756.93
2006	10,584.90	1,279	(2)	1,279.00	9,305.90	13	715.84
2007	15,918.93	1,165	(2)	1,165.00	14,753.93	14	1,053.85
2008	0.00	0	(2)	0.00	0.00	15	0.00
	415,861.93	173,825		196,474.04	219,387.89	6.32%	26,263.11

Book Reserve	179,231.41		
Starting Point Depreciation Reserve	196,474.04		
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)	17,242.63	15	1,149.51
Total Amortization Amount		6.59%	27,412.62

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Montana-Dakota Utilities Company
Gas Division
Account 391.30 - Computer Equipment - PC

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R2
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2000	0.00	0	(1)	0.00	0.00	0	0.00
2001	0.00	0	(1)	0.00	0.00	0	0.00
2002	1,020.09	844	(1)	1,020.09	0.00	0	0.00
2003	161,255.28	122,499	(1)	161,255.28	0.00	0	0.00
2004	219,235.28	146,494	(2)	146,494.00	72,741.28	1	72,741.28
2005	163,217.13	90,089	(2)	90,089.00	73,128.13	2	36,564.07
2006	110,818.82	45,905	(2)	45,905.00	64,913.82	3	21,637.94
2007	99,484.66	25,760	(2)	25,760.00	73,724.66	4	18,431.17
2008	73,086.95	6,529	(2)	6,529.00	66,557.95	5	13,311.59
	828,118.21	438,120		477,052.37	351,065.84	3.16%	162,686.04

Book Reserve	823,565.05		
Starting Point Depreciation Reserve	477,052.37		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	-346,512.68	5	-69,302.54
Total Amortization Amount		11.28%	93,383.50

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 391.50 - Other Computer Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R2
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2007	25,878.68	6,701	(2)	6,701.00	19,177.68	4	4,794.42
2008	27,818.16	2,485	(2)	2,485.00	25,333.16	5	5,066.63
	53,696.84	9,186		9,186.00	44,510.84	3.16%	9,861.05
Book Reserve				8,767.81			
Starting Point Depreciation Reserve				9,186.00			
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)				418.19		5	9,857.85
Total Amortization Amount						4.97%	27,033.65

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **35** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1956	0.00	0	(1)	0.00	0.00	0	0.00
1957	0.00	0	(1)	0.00	0.00	0	0.00
1958	15.51	15	(1)	15.51	0.00	0	0.00
1959	430.38	401	(1)	430.38	0.00	0	0.00
1960	2,526.36	2,335	(1)	2,526.36	0.00	0	0.00
1961	553.94	508	(1)	553.94	0.00	0	0.00
1962	1,082.68	985	(1)	1,082.68	0.00	0	0.00
1963	1,045.67	943	(1)	1,045.67	0.00	0	0.00
1964	485.33	434	(1)	485.33	0.00	0	0.00
1965	0.00	0	(1)	0.00	0.00	0	0.00
1966	2,157.35	1,895	(1)	2,157.35	0.00	0	0.00
1967	1,651.60	1,436	(1)	1,651.60	0.00	0	0.00
1968	5,567.94	4,791	(1)	5,567.94	0.00	0	0.00
1969	516.52	439	(1)	516.52	0.00	0	0.00
1970	1,330.08	1,118	(1)	1,330.08	0.00	0	0.00
1971	9,040.24	7,496	(1)	9,040.24	0.00	0	0.00
1972	2,993.64	2,447	(1)	2,993.64	0.00	0	0.00
1973	5,710.69	4,595	(1)	5,710.69	0.00	0	0.00
1974	1,448.26	1,146	(2)	1,146.00	302.26	1	302.26
1975	967.22	752	(2)	752.00	215.22	2	107.61
1977	2,974.56	2,220	(2)	2,220.00	754.56	4	188.64
1978	7,363.43	5,375	(2)	5,375.00	1,988.43	5	397.69
1979	0.00	0	(2)	0.00	0.00	6	0.00
1980	2,475.39	1,720	(2)	1,720.00	755.39	7	107.91
1981	0.00	0	(2)	0.00	0.00	8	0.00
1982	608.44	400	(2)	400.00	208.44	9	23.16
1983	0.00	0	(2)	0.00	0.00	10	0.00
1984	0.00	0	(2)	0.00	0.00	11	0.00
1985	0.00	0	(2)	0.00	0.00	12	0.00
1986	2,247.72	1,293	(2)	1,293.00	954.72	13	73.44
1987	12,024.02	6,656	(2)	6,656.00	5,368.02	14	383.43
1988	0.00	0	(2)	0.00	0.00	15	0.00
1989	0.00	0	(2)	0.00	0.00	16	0.00
1990	761.71	370	(2)	370.00	391.71	17	23.04
1991	0.00	0	(2)	0.00	0.00	18	0.00
1992	14,689.00	6,436	(2)	6,436.00	8,253.00	19	434.37
1993	852.74	353	(2)	353.00	499.74	20	24.99
1994	11,358.34	4,420	(2)	4,420.00	6,938.34	21	330.40
1995	0.00	0	(2)	0.00	0.00	22	0.00
1996	1,284.52	435	(2)	435.00	849.52	23	36.94
1997	0.00	0	(2)	0.00	0.00	24	0.00
1998	0.00	0	(2)	0.00	0.00	25	0.00

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 35 R3
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1999	0.00	0	(2)	0.00	0.00	26	0.00
2000	697.76	163	(2)	163.00	534.76	27	19.81
2001	19,702.69	4,085	(2)	4,085.00	15,617.69	28	557.77
2002	14,197.38	2,559	(2)	2,559.00	11,638.38	29	401.32
2003	14,253.48	2,180	(2)	2,180.00	12,073.48	30	402.45
2004	0.00	0	(2)	0.00	0.00	31	0.00
2005	5,267.69	515	(2)	515.00	4,752.69	32	148.52
2006	0.00	0	(2)	0.00	0.00	33	0.00
2007	0.00	0	(2)	0.00	0.00	34	0.00
2008	0.00	0	(2)	0.00	0.00	35	0.00
	148,282.28	70,916		76,185.93	72,096.35	2.67%	3,963.74

Book Reserve	88,443.55		
Starting Point Depreciation Reserve	76,185.93		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	-12,257.62	35	-350.22
Total Amortization Amount		2.44%	3,613.53

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Montana-Dakota Utilities Company
Gas Division
Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 18 R1.5
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1978	0.00	0	(1)	0.00	0.00	0	0.00
1979	0.00	0	(1)	0.00	0.00	0	0.00
1980	10,467.90	9,204	(1)	10,467.90	0.00	0	0.00
1981	45,439.51	39,280	(1)	45,439.51	0.00	0	0.00
1982	38,635.11	32,802	(1)	38,635.11	0.00	0	0.00
1983	12,607.97	10,500	(1)	12,607.97	0.00	0	0.00
1984	0.00	0	(1)	0.00	0.00	0	0.00
1985	139,100.33	111,035	(1)	139,100.33	0.00	0	0.00
1986	84,211.26	65,644	(1)	84,211.26	0.00	0	0.00
1987	14,238.35	10,815	(1)	14,238.35	0.00	0	0.00
1988	21,344.59	15,757	(1)	21,344.59	0.00	0	0.00
1989	45,044.89	32,224	(1)	45,044.89	0.00	0	0.00
1990	36,693.43	25,354	(1)	36,693.43	0.00	0	0.00
1991	24,443.91	16,253	(2)	16,253.00	8,190.91	1	8,190.91
1992	53,753.21	34,256	(2)	34,256.00	19,497.21	2	9,748.61
1993	11,046.15	6,716	(2)	6,716.00	4,330.15	3	1,443.38
1994	207,471.21	119,751	(2)	119,751.00	87,720.21	4	21,930.05
1995	11,983.39	6,529	(2)	6,529.00	5,454.39	5	1,090.88
1996	88,738.37	45,348	(2)	45,348.00	43,390.37	6	7,231.73
1997	79,855.62	38,003	(2)	38,003.00	41,852.62	7	5,978.95
1998	75,440.20	33,152	(2)	33,152.00	42,288.20	8	5,286.03
1999	60,557.07	24,334	(2)	24,334.00	36,223.07	9	4,024.79
2000	103,232.71	37,483	(2)	37,483.00	65,749.71	10	6,574.97
2001	88,807.59	28,719	(2)	28,719.00	60,088.59	11	5,462.60
2002	136,247.42	38,521	(2)	38,521.00	97,726.42	12	8,143.87
2003	140,533.90	33,908	(2)	33,908.00	106,625.90	13	8,201.99
2004	132,041.11	26,282	(2)	26,282.00	105,759.11	14	7,554.22
2005	194,448.84	30,348	(2)	30,348.00	164,100.84	15	10,940.06
2006	279,393.80	31,400	(2)	31,400.00	247,993.80	16	15,499.61
2007	231,829.38	15,756	(2)	15,756.00	216,073.38	17	12,710.20
2008	148,031.67	3,381	(2)	3,381.00	144,650.67	18	8,036.15
	2,515,638.89	922,755		1,017,923.34	1,497,715.55	5.89%	148,048.98

Book Reserve	1,124,846.96		
Starting Point Depreciation Reserve	1,017,923.34		
Book/Amortization Starting Point Depr Reserve Varianc (Amortize over Amortization Period)	-106,923.62	18	-5,940.20
Total Amortization Amount		5.65%	142,108.78

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 394.3 - Vehicle Maintainence Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20 R3
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1987	5,304.03	4,403	(1)	5,304.03	0.00	0	0.00
1988	0.00	0	(1)	0.00	0.00	0	0.00
1989	3,393.19	2,666	(2)	2,666.00	727.19	1	727.19
1990	0.00	0	(2)	0.00	0.00	2	0.00
1991	8,613.81	6,304	(2)	6,304.00	2,309.81	3	769.94
1992	261.32	183	(2)	183.00	78.32	4	19.58
1993	1,728.56	1,157	(2)	1,157.00	571.56	5	114.31
1994	11,875.67	7,542	(2)	7,542.00	4,333.67	6	722.28
1995	0.00	0	(2)	0.00	0.00	7	0.00
1996	0.00	0	(2)	0.00	0.00	8	0.00
1997	0.00	0	(2)	0.00	0.00	9	0.00
1998	0.00	0	(2)	0.00	0.00	10	0.00
1999	0.00	0	(2)	0.00	0.00	11	0.00
2000	0.00	0	(2)	0.00	0.00	12	0.00
2001	0.00	0	(2)	0.00	0.00	13	0.00
2002	0.00	0	(2)	0.00	0.00	14	0.00
2003	0.00	0	(2)	0.00	0.00	15	0.00
2004	0.00	0	(2)	0.00	0.00	16	0.00
2005	0.00	0	(2)	0.00	0.00	17	0.00
2006	5,923.44	723	(2)	723.00	5,200.44	18	288.91
2007	0.00	0	(2)	0.00	0.00	19	0.00
2008	0.00	0	(2)	0.00	0.00	20	0.00
	37,100.02	22,978		23,879.03	13,220.99	7.12%	2,642.21

Book Reserve	23,917.83		
Starting Point Depreciation Reserve	23,879.03		
Book/Amortization Starting Point Depr Reserve Var (Amortize over Amortization Period)	-38.80	20	-1.94
Total Amortization Amount		7.12%	2,640.27

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 394.4 - Vehicle Refueling Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1995	0.00	0	(2)	0.00	0.00	2	0.00
1996	26,852.90	18,972	(2)	18,972.00	7,880.90	3	2,626.97
1997	0.00	0	(2)	0.00	0.00	4	0.00
1998	0.00	0	(2)	0.00	0.00	5	0.00
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	0.00	0	(2)	0.00	0.00	7	0.00
2001	0.00	0	(2)	0.00	0.00	8	0.00
2002	0.00	0	(2)	0.00	0.00	9	0.00
2003	0.00	0	(2)	0.00	0.00	10	0.00
2004	0.00	0	(2)	0.00	0.00	11	0.00
2005	0.00	0	(2)	0.00	0.00	12	0.00
2006	0.00	0	(2)	0.00	0.00	13	0.00
2007	0.00	0	(2)	0.00	0.00	14	0.00
2008	0.00	0	(2)	0.00	0.00	15	0.00
	26,852.90	18,972		18,972.00	7,880.90	9.78%	2,626.97

Book Reserve	16,795.80		
Starting Point Depreciation Reserve	18,972.00		
Book/Amortization Starting Point Depr Reserve Varianc((Amortize over Amortization Period)	2,176.20	15	145.08
Total Amortization Amount		10.32%	2,772.05

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 395 - Laboratory Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20 R2
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1981	0.00	0	(1)	0.00	0.00	0	0.00
1982	0.00	0	(1)	0.00	0.00	0	0.00
1983	8,582.06	7,143	(1)	8,582.06	0.00	0	0.00
1984	2,706.78	2,207	(1)	2,706.78	0.00	0	0.00
1985	17,869.81	14,245	(1)	17,869.81	0.00	0	0.00
1987	17,045.88	12,903	(1)	17,045.88	0.00	0	0.00
1988	1,235.97	908	(1)	1,235.97	0.00	0	0.00
1989	1,656.98	1,178	(2)	1,178.00	478.98	1	478.98
1990	522.68	358	(2)	358.00	164.68	2	82.34
1991	14,199.27	9,357	(2)	9,357.00	4,842.27	3	1,614.09
1992	1,179.16	744	(2)	744.00	435.16	4	108.79
1993	4,433.74	2,666	(2)	2,666.00	1,767.74	5	353.55
1994	0.00	0	(2)	0.00	0.00	6	0.00
1995	20,858.40	11,221	(2)	11,221.00	9,637.40	7	1,376.77
1996	1,164.44	587	(2)	587.00	577.44	8	72.18
1997	0.00	0	(2)	0.00	0.00	9	0.00
1998	0.00	0	(2)	0.00	0.00	10	0.00
1999	0.00	0	(2)	0.00	0.00	11	0.00
2000	22,599.05	8,108	(2)	8,108.00	14,491.05	12	1,207.59
2001	5,104.84	1,632	(2)	1,632.00	3,472.84	13	267.14
2002	53,124.91	14,863	(2)	14,863.00	38,261.91	14	2,732.99
2003	0.00	0	(2)	0.00	0.00	15	0.00
2004	0.00	0	(2)	0.00	0.00	16	0.00
2005	0.00	0	(2)	0.00	0.00	17	0.00
2006	0.00	0	(2)	0.00	0.00	18	0.00
2007	0.00	0	(2)	0.00	0.00	19	0.00
2008	0.00	0	(2)	0.00	0.00	20	0.00
	172,283.97	88,120		98,154.50	74,129.47	4.81%	8,294.42

Book Reserve	24,442.45		
Starting Point Depreciation Reserve	98,154.50		
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)	73,712.05	20	3,685.60
Total Amortization Amount		6.95%	11,980.02

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Montana-Dakota Utilities Company
Gas Division
Account 397.1 - Radio Communication Equipment (Fixed)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1987	0.00	0	(1)	0.00	0.00	0	0.00
1988	0.00	0	(1)	0.00	0.00	0	0.00
1989	0.00	0	(1)	0.00	0.00	0	0.00
1990	0.00	0	(1)	0.00	0.00	0	0.00
1991	70,527.50	60,805	(1)	70,527.50	0.00	0	0.00
1992	0.00	0	(1)	0.00	0.00	0	0.00
1993	0.00	0	(1)	0.00	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	17,943.49	13,384	(2)	13,384.00	4,559.49	2	2,279.75
1996	19,525.74	13,795	(2)	13,795.00	5,730.74	3	1,910.25
1997	17,886.14	11,867	(2)	11,867.00	6,019.14	4	1,504.79
1998	1,719.80	1,061	(2)	1,061.00	658.80	5	131.76
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	0.00	0	(2)	0.00	0.00	7	0.00
2001	18,737.92	8,656	(2)	8,656.00	10,081.92	8	1,260.24
2002	27,774.34	11,265	(2)	11,265.00	16,509.34	9	1,834.37
2003	0.00	0	(2)	0.00	0.00	10	0.00
2004	10,670.34	3,063	(2)	3,063.00	7,607.34	11	691.58
2005	0.00	0	(2)	0.00	0.00	12	0.00
2006	16,384.34	2,655	(2)	2,655.00	13,729.34	13	1,056.10
2007	25,677.39	2,512	(2)	2,512.00	23,165.39	14	1,654.67
2008	0.00	0	(2)	0.00	0.00	15	0.00
	226,847.00	129,063		138,785.50	88,061.50	5.43%	12,323.50

Book Reserve	117,179.40		
Starting Point Depreciation Reserve	138,785.50		
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)	21,606.10	15	1,440.41
Total Amortization Amount		6.07%	13,763.90

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 397.2 - Radio Communication Equipment (Mobile)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1991	0.00	0	(1)	0.00	0.00	0	0.00
1992	234,529.05	196,806	(1)	234,529.05	0.00	0	0.00
1993	14,099.41	11,453	(1)	14,099.41	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	18,861.62	14,069	(2)	14,069.00	4,792.62	2	2,396.31
1996	11,115.37	7,853	(2)	7,853.00	3,262.37	3	1,087.46
1997	7,034.48	4,667	(2)	4,667.00	2,367.48	4	591.87
1998	2,166.65	1,337	(2)	1,337.00	829.65	5	165.93
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	57,474.36	29,665	(2)	29,665.00	27,809.36	7	3,972.77
2001	0.00	0	(2)	0.00	0.00	8	0.00
2002	15,101.42	6,125	(2)	6,125.00	8,976.42	9	997.38
2003	0.00	0	(2)	0.00	0.00	10	0.00
2004	3,093.15	888	(2)	888.00	2,205.15	11	200.47
2005	0.00	0	(2)	0.00	0.00	12	0.00
2006	1,624.26	263	(2)	263.00	1,361.26	13	104.71
2007	5,743.94	562	(2)	562.00	5,181.94	14	370.14
2008	98,031.63	3,213	(2)	3,213.00	94,818.63	15	6,321.24
	468,875.34	276,901		317,270.46	151,604.88	3.46%	16,208.27

Book Reserve	274,608.16		
Starting Point Depreciation Reserve	317,270.46		
Book/Amortization Starting Point Depr Reserve Va (Amortize over Amortization Period)	42,662.30	15	2,844.15
Total Amortization Amount		4.06%	19,052.43

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 397.3 - General Telephone Communication Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **10** R1
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1991	0.00	0	(1)	0.00	0.00	**0**	0.00
1992	0.00	0	(1)	0.00	0.00	**0**	0.00
1993	1,982.48	1,686	(1)	1,982.48	0.00	**0**	0.00
1994	979.46	800	(1)	979.46	0.00	**0**	0.00
1995	0.00	0	(1)	0.00	0.00	**0**	0.00
1996	5,341.73	3,965	(1)	5,341.73	0.00	**0**	0.00
1997	0.00	0	(1)	0.00	0.00	**0**	0.00
1998	236.42	155	(1)	236.42	0.00	**0**	0.00
1999	2,071.91	1,258	(2)	1,258.00	813.91	**1**	813.91
2000	0.00	0	(2)	0.00	0.00	**2**	0.00
2001	0.00	0	(2)	0.00	0.00	**3**	0.00
2002	11,527.07	5,084	(2)	5,084.00	6,443.07	**4**	1,610.77
2003	0.00	0	(2)	0.00	0.00	**5**	0.00
2004	3,609.94	1,135	(2)	1,135.00	2,474.94	**6**	412.49
2005	31,198.68	7,723	(2)	7,723.00	23,475.68	**7**	3,353.67
2006	0.00	0	(2)	0.00	0.00	**8**	0.00
2007	0.00	0	(2)	0.00	0.00	**9**	0.00
2008	0.00	0	(2)	0.00	0.00	**10**	0.00
	56,947.69	21,806		23,740.09	33,207.60	10.87%	6,190.84

Book Reserve	24,756.98		
Starting Point Depreciation Reserve	23,740.09		
Book/Amortization Starting Point Depr Reserve Variar (Amortize over Amortization Period)	-1,016.89	10	-101.69
Total Amortization Amount		10.69%	6,089.15

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 397.8 - Network Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1997	0.00		(1)	0.00	0.00	0	0.00
1998	0.00		(1)	0.00	0.00	0	0.00
1999	0.00		(1)	0.00	0.00	0	0.00
2000	0.00		(1)	0.00	0.00	0	0.00
2001	4,440.95	3,997	(1)	4,440.95	0.00	0	0.00
2002	1,360.68	1,194	(1)	1,360.68	0.00	0	0.00
2003	2,420.43	2,003	(1)	2,420.43	0.00	0	0.00
2004	1,076.81	798	(2)	798.00	278.81	1	278.81
2005	0.00		(2)	0.00	0.00	2	0.00
2006	31,232.56	14,401	(2)	14,401.00	16,831.56	3	5,610.52
2007	114,735.71	32,898	(2)	32,898.00	81,837.71	4	20,459.43
2008	16,879.67	1,651	(2)	1,651.00	15,228.67	5	3,045.73
	172,146.81	56,942		57,970.06	114,176.75	17.08%	29,394.49
Book Reserve				52,766.76			
Starting Point Depreciation Reserve				57,970.06			
Book/Amortization Starting Point Depr Reserve Vai (Amortize over Amortization Period)				5,203.30		5	1,040.66
Total Amortization Amount						17.68%	30,435.15

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Gas Division
Account 398 - Miscellaneous Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **20** R2
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1980	0.00	0	(1)	0.00	0.00	**0**	0.00
1981	0.00	0	(1)	0.00	0.00	**0**	0.00
1982	517.46	439	(1)	517.46	0.00	**0**	0.00
1983	2,295.46	1,911	(1)	2,295.46	0.00	**0**	0.00
1984	940.17	766	(1)	940.17	0.00	**0**	0.00
1985	1,072.89	855	(1)	1,072.89	0.00	**0**	0.00
1986	150.93	117	(1)	150.93	0.00	**0**	0.00
1987	0.00	0	(1)	0.00	0.00	**0**	0.00
1988	259.43	191	(1)	259.43	0.00	**0**	0.00
1989	512.29	364	(2)	364.00	148.29	**1**	148.29
1990	1,079.95	741	(2)	741.00	338.95	**2**	169.48
1991	2,406.18	1,586	(2)	1,586.00	820.18	**3**	273.39
1992	3,002.27	1,894	(2)	1,894.00	1,108.27	**4**	277.07
1993	2,104.05	1,265	(2)	1,265.00	839.05	**5**	167.81
1994	20,687.82	11,798	(2)	11,798.00	8,889.82	**6**	1,481.64
1995	0.00	0	(2)	0.00	0.00	**7**	0.00
1996	2,257.88	1,139	(2)	1,139.00	1,118.88	**8**	139.86
1997	1,968.54	925	(2)	925.00	1,043.54	**9**	115.95
1998	2,379.33	1,032	(2)	1,032.00	1,347.33	**10**	134.73
1999	0.00	0	(2)	0.00	0.00	**11**	0.00
2000	493.66	177	(2)	177.00	316.66	**12**	26.39
2001	1,357.10	434	(2)	434.00	923.10	**13**	71.01
2002	2,240.64	627	(2)	627.00	1,613.64	**14**	115.26
2003	541.85	129	(2)	129.00	412.85	**15**	27.52
2004	0.00	0	(2)	0.00	0.00	**16**	0.00
2005	0.00	0	(2)	0.00	0.00	**17**	0.00
2006	10,582.30	1,178	(2)	1,178.00	9,404.30	**18**	522.46
2007	0.00	0	(2)	0.00	0.00	**19**	0.00
2008	0.00	0	(2)	0.00	0.00	**20**	0.00
	56,850.20	27,568		28,525.34	28,324.86	6.46%	3,670.85

Book Reserve	-5,285.64		
Starting Point Depreciation Reserve	28,525.34		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	33,810.98	20	1,690.55
Total Amortization Amount		9.43%	5,361.40

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

MONTANA-DAKOTA UTILITIES

Gas Division

General

This report sets forth the results of our study of the depreciable property of Montana-Dakota Utilities - Gas (MDU or the Company) as of December 31, 2008 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2008.

The scope of the study included an analysis of MDU's historical data through December 31, 2008, discussions with Company management and staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant. The service lives and life characteristics resulting from the in-depth study were utilized together with the Company's plant in service and book depreciation reserve to determine the recommended Average Remaining Life (ARL) depreciation rates for the Company's plant in service as of December 31, 2008.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the MDU's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property.

The Company maintains property records containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line Group Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Average Remaining Life Technique.

The distinction between the Whole Life and Remaining Life Techniques is that under the Whole Life Technique, the depreciation rate is based on the recovery of the investment and average net salvage over the average service life of the property group. In comparison, under the Average Remaining Life Technique, the resulting annual depreciation rate incorporates the recovery of the investment (and future net salvage) less any recovery experienced to date over the average remaining life of the property group.

That is, the Average Remaining Life technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. As the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's average remaining life depreciation rate in subsequent years will be increased or decreased to compensate for the variance, thereby, assuring full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be recognized is based upon the remaining productive life over which the un-depreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Average Remaining Life Technique, the Company will recover the un-depreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintaged surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the ARL technique meets the objective of providing a straight line recovery of the un-depreciated fixed capital property investment.

The use of the Average Remaining Life Technique results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by the end of the life of the property. The annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group Depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption that the retired property was at average service life.

<u>Group Depreciation Procedures</u>

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

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average life of the overall property group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is viewed as being the more definitive procedure for identifying the life characteristics of utility property and as a basis for developing service lives and depreciation rates, nevertheless, the Broad Group procedure is more widely utilized throughout the utility industry by regulatory commissions as a basis for depreciation rates. That is, the ELG Procedure is more definitive because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby not only reducing the risk of incomplete cost recovery, but also resulting in less return on rate base over the life of a depreciable group. The total depreciation expense over the life of the property is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the Equal Life Group procedure has been known to depreciation experts for many years, widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at

XYZ UTILITY COMPANY

CALCULATION OF ASL, ARL AND ACCRUED DEPRECIATION FACTORS — Table 8

BASED UPON AN NEW YORK STATE (KIMBALL) h3.00 CURVE USING THE EQUAL LIFE GROUP (ELG) PROCEDURE

							EQUAL LIFE GROUP PROCEDURE			
AGE AT BEGIN OF INTERVAL	LIFE TABLE BEGIN OF INTERVAL	RETIREMENT DURING INTERVAL	AVERAGE SURVIVING	AGE OF AMOUNT RETIRED	AMOUNT FOR EACH LIFE GROUP	AMOUNT FOR REMAINING LIFE GROUPS	AVERAGE SERVICE LIFE	AVERAGE REMAINING LIFE	ELG/ARL DEPR RATE	ACCRUED DEPR RES FACTOR
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
0.0	1.0000000	0.0006400	0.9996800	0.25	0.0006400	0.0587873	8.50	8.50	11.76	0.0000000
0.5	0.9993600	0.0029600	0.9978800	1.0	0.0029600	0.1148146	8.69	8.19	11.51	0.0575293
1.5	0.9964000	0.0064000	0.9932000	2.0	0.0032000	0.1117346	8.89	7.39	11.25	0.1687494
2.5	0.9900000	0.0126200	0.9836900	3.0	0.0042067	0.1080313	9.11	6.61	10.98	0.2745562
3.5	0.9773800	0.0227600	0.9660000	4.0	0.0056900	0.1030830	9.37	5.87	10.67	0.3734890
4.5	0.9546200	0.0375500	0.9358450	5.0	0.0075100	0.0964830	9.70	5.20	10.31	0.4639372
5.5	0.9170700	0.0566100	0.8887650	6.0	0.0094350	0.0880105	10.10	4.60	9.90	0.5446406
6.5	0.8604600	0.0780600	0.8214300	7.0	0.0111514	0.0777172	10.57	4.07	9.46	0.6149789
7.5	0.7824000	0.0984200	0.7331900	8.0	0.0123025	0.0659903	11.11	3.61	9.00	0.6750325
8.5	0.6839800	0.1134200	0.6272700	9.0	0.0126022	0.0535379	11.72	3.22	8.54	0.7254808
9.5	0.5705600	0.1195400	0.5107900	10.0	0.0119540	0.0412598	12.38	2.88	8.08	0.7673764
10.5	0.4510200	0.1151700	0.3934350	11.0	0.0104700	0.0300478	13.09	2.59	7.64	0.8019165
11.5	0.3358500	0.1014600	0.2851200	12.0	0.0084550	0.0205853	13.85	2.35	7.22	0.8302857
12.5	0.2343900	0.0817300	0.1935250	13.0	0.0062869	0.0132143	14.65	2.15	6.83	0.8535298
13.5	0.1526600	0.0601800	0.1225700	14.0	0.0042986	0.0079216	15.47	1.97	6.46	0.8724942
14.5	0.0924800	0.0405200	0.0722200	15.0	0.0027013	0.0044216	16.33	1.83	6.12	0.8877583
15.5	0.0519600	0.0249500	0.0394850	16.0	0.0015594	0.0022913	17.23	1.73	5.80	0.8994571
16.5	0.0270100	0.0140400	0.0199900	17.0	0.0008259	0.0010987	18.19	1.69	5.50	0.9068526
17.5	0.0129700	0.0072300	0.0093550	18.0	0.0004017	0.0004849	19.29	1.79	5.18	0.9070652
18.5	0.0057400	0.0000000	0.0057400	19.0	0.0000000	0.0002841	20.21	1.71	4.95	0.9155172
19.5	0.0057400	0.0048600	0.0033100	20.0	0.0002430	0.0001626	20.36	0.86	4.91	0.9576667
20.5	0.0008800	0.0005800	0.0005900	21.0	0.0000276	0.0000272	21.65	1.15	4.62	0.9467615
21.5	0.0003000	0.0002000	0.0002000	22.0	0.0000091	0.0000089	22.49	0.99	4.45	0.9560277
22.5	0.0001000	0.0001000	0.0000500	23.0	0.0000043	0.0000022	23.00	0.50	4.35	0.9782609
23.5	0.0000000	0.0000000	0.0000000	24.0	0.0000000	0.0000000				
		1.0000000				1.0000000				

the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column (B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 1/2 to 4 1/2, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 1/2 to 5 1/2 and experiences a service life of five years. Furthermore, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. In as much as additions retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to .5 must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover 100% of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34% (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

Remaining Life Technique

As previously noted, while I prefer the Average Remaining Life Technique (because it considers all factors in developing the applicable depreciation rates) the NY Commission and its staff have indicated that the Whole Life depreciation Technique should be used to develop depreciation rates other than for Electric generating facilities.

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant less (U) the accumulated provision for depreciation less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining lives are determined for each depreciable group, (i.e., property account).

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is determined by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R\ \text{Group} = \frac{\sum D/L \times E}{\sum D/L}$$

The accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account as per this report, was obtained from the Company's books and records.

Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant, as well as normal environmental clean up costs associated with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

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

Many retired assets generate little, if any, positive salvage. Instead, many of the Company's asset property groups generate negative net salvage at end of their life as a result of the cost of removal (retirement).

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

The Company's historical net salvage experience was analyzed to identify the historical net salvage factor for each applicable property group. This analysis routinely identifies that historical retirements have occurred at average ages significantly prior to the property group's average service life. This occurrence of historical retirements, at an age which is significantly younger than the average service life of the property category, clearly demonstrates that the historical data does not appropriately recognize the true level of retirement cost at the end of the property's useful life. An additional level of cost to retire will occur due to the passage of time until all the current in service plant is retired at end of life. That is, the level of retirement costs will increase over time until the average service life is attained. The estimated additional inflation, within the estimate of retirement cost, is related to those additional year's cost increases (primarily higher labor costs over time) that will occur prior to the end of the property group's average life.

To provide an additional explanation of the issue, several general principles surrounding property retirements and related net salvage need to be highlighted. Those are that as property continues to age, the retirement of assets, if generating positive salvage when retired, will typically generate a lower percent of positive salvage. By comparison, if the class of property is one that typically generates negative net salvage (cost of removal), with increasing age at retirement the negative percentage as related to original cost will typically be greater. This situation is routinely driven by the higher labor cost with the passage of time.

Next, a simple example will aid in a better understanding of the above discussed net salvage analysis and the required adjustment to the historical analysis results. Assume the following scenario. A company has two (2) 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 (2 Yrs. Plus 10 Yrs./2). 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 analysis indication is incorrect and 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 with the majority of the Company's historical net salvage data except that most of the Company's plant property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

The total end of life net salvage amount must be incorporated in the development of annual depreciation rates to enable the Company to fully recover its total plant life costs. Otherwise, upon retirement of the plant, the Company will incur end of life costs without having recovered those plant related costs from the customers who benefitted from the use of the expired plant.

With regard to location type properties (e.g. generation facilities, etc.) a company will routinely experience both interim and terminal net salvage. Interim net salvage occurs in conjunction with interim retirements that occur throughout the life of the asset group. This net salvage activity (routinely and largely cost of removal) is attributable to the removal of components within the Company's facilities to enable the placement of a new asset component. Interim net salvage is routinely negative given the care required in removing the defective component so as not to damage the remaining plant in service. Interim net salvage is applicable to the estimated interim retirement assets.

The terminal net salvage component is attributable to the end of life costs incurred (less any gross salvage received) to disconnect, remove, demolish and/or dispose of the operating asset. Terminal net salvage is attributable to those assets remaining in service subsequent to the occurrence of interim retirements.

The total net salvage incorporated into the depreciation rate for location type plant account investments is the sum of interim and terminal net salvage. Both of the items must be incorporated in the development of annual depreciation rates to enable the Company to fully recover its total plant life costs. Otherwise, upon retirement of the plant, the Company will incur end of life costs without having recovered those plant related costs from the customers who benefitted from the use of the expired facility.

Service Lives

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

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

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

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family of curves are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Furthermore, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgment Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company retirement experience to develop a survivor curve (Observed Life Table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least squares technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each proceeding year's original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes a Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If, in the past, the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date.

Judgment Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgment are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgment alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what is considered to be a reasonable life for this plant giving consideration to the current age and use of the facilities.

MONTANA-DAKOTA UTILITIES CO. - GAS

Study Analysis & Results

ACCOUNT – 374.20 Land Rights

Historical Experience

Plant Statistics
Plant Balance = $322,678
Original Gross Additions = $275,515
Oldest Surviving Vintage = 1977
Retirements = $36,507 or 13.3% of historical additions.

Experience Bands 1977-08 (Simulated) 65-R3

Historic Net Salvage: (85-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1977-2008
23%	0%	0%	1%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
9%	10%	9%	0%

Forecasted Net Salvage: 0%

Plant Considerations/Future Expectations

The investments in this limited account are related to rights of way acquired by the Company for the purpose of installing components of its utility plant.

Life Analysis Method: Simulated Plant Analysis Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 65-R2.5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 65-R3
Future Net Salv: 0%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	1.39%	0.75%
Average Remaining Life	57.2 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 375.00 Distr. Meas. & Reg. Structures And Improvements

Historical Experience

Plant Statistics	Plant Balance = $609,311 Original Gross Additions = $896,007 Oldest Surviving Vintage = 1918 Retirements = $145,619 or 16.3% of historical additions.
Experience Bands	1918- 08 (Simulated) 60-R3

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-54%	-61%	-40%	-26%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
3%	0%	0%	0%

Forecasted Net Salvage: -82%

Plant Considerations/Future Expectations

The costs included in this account investment are related to various distribution related structures. Ongoing changes occur due to required component upgrades as well as changes in business environment conditions. End of life costs relative to rehabilitation or disposal is routinely experience within this property class.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

Interim Retirement ASL/Curve: 55-R2.5
Net Salv: -50%

Proposed Depreciation Parameters

Interim Retirement ASL/Curve: 60-R3
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.77%	2.57 %
Average Remaining Life	33.0 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.10 Distribution Mains – Steel

Historical Experience

Plant Statistics	Plant Balance = $41,975,049 Original Gross Additions = $113,372,232 (Total Account) Oldest Surviving Vintage = 1904 Retirements = $6,061,120 (Total Account) or 5.3% of historical additions.
Experience Bands	1916 – 2008 (Simulated) 47-R4
Historic Net Salvage:	(68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-27%	-35%	-25%	-32%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
2%	0%	0%	0%

Forecasted Net Salvage: -92%

Plant Considerations/Future Expectations

This property group is comprised of the Company's investment and related experience of Steel Distribution Mains. While portions of this property class (bare steel) were originally installed during earlier years, coated and wrapped steel has continue to be installed for higher pressure and larger size requirements. The earlier vintage assets in this account have aged considerably. Likewise, due to the lack of serviceability of the older vintaged property (which are Bare Steel Mains) contained within the Steel Mains category, they are being replaced.

Life Analysis Method: Simulated Plant Analysis Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -60%

Proposed Depreciation Parameters

ASL/Curve: 47-R4
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.84%	1.92%
Average Remaining Life	22.3 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.20 Distribution Mains – Plastic

Historical Experience

Plant Statistics	Plant Balance = $63,935,959 Original Gross Additions = $113,372,232 (Total Account) Oldest Surviving Vintage = 1969 Retirements = $6,061,120 (Total Account) or 5.3% of historical additions.
Experience Bands	1916 – 2008 (Simulated) 47-R4
Historic Net Salvage:	(68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-27%	-35%	-25%	-32%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
2%	0%	0%	0%

Forecasted Net Salvage: -92%

Plant Considerations/Future Expectations

This property group investment is comprised of the Company's investment and related experience of Plastic Distribution Mains and are typically related to the more recently installed portions of Mains. Studies of this class of property, in numerous completed depreciation studies, have identified that Plastic Mains routinely experience shorter lives than their metal counterparts. Such shorter lives are the product of higher levels of physical issues (e.g. physical damage, etc) impacting the mains as well as the fact that the Plastic mains have often been installed in areas that experience higher growth and replacements.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -60%

Proposed Depreciation Parameters

ASL/Curve: 47-R4
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.05%	1.92%
Average Remaining Life	33.4 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.30 Mains – Valves

Historical Experience

Plant Statistics: Plant Balance = $447,328
Original Gross Additions =$113,372,232 (Total Account)
Oldest Surviving Vintage = 1904
Retirements = $6,061,120 (Total Account) or 5.3% of historical additions.

Experience Bands: Estimated 40-R2.5

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-27%	-35%	-25%	-32%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
2%	0%	0%	0%

Forecasted Net Salvage: -92%

Plant Considerations/Future Expectations

This account is comprised of costs related to recent vintage Valves installed in the distribution system. Given the mechanical nature of the property the class is anticipated to have a shorter life than Mains pipe.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 40-R2.5
Net Salv: -60%

Proposed Depreciation Parameters

ASL/Curve: 40-R2.5
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.54%	1.92%
Average Remaining Life	26.1 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.40 Mains – Manholes

Historical Experience

Plant Statistics
Plant Balance = $69,919
Original Gross Additions =$113,372,232 (Total Account)
Oldest Surviving Vintage = 1960
Retirements = $6,061,120 (Total Account) or 5.3% of historical additions.

Experience Bands 1916-2008 (Simulated) 47-R4

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-27%	-35%	-25%	-32%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
2%	0%	0%	0%

Forecasted Net Salvage: -92%

Plant Considerations/Future Expectations

The investment in this property category is limited and is anticipated to experience a life generally similar to the overall Mains.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -60%

Proposed Depreciation Parameters

ASL/Curve: 47-R4
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.89%	1.92%
Average Remaining Life	24.6%	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 376.50 Bridge & River Crossings

Historical Experience

Plant Statistics	Plant Balance = $19,818 Original Gross Additions =$113,372,232 (Total Account) Oldest Surviving Vintage = 1995 Retirements = $6,061,120 (Total Account) or 5.3% of historical additions.
Experience Bands	1916-2008 (Simulated) 47-R4
Historic Net Salvage:	(68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-27%	-35%	-25%	-32%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
2%	0%	0%	0%

Forecasted Net Salvage: -92%

Plant Considerations/Future Expectations

The investment in this property category is limited and is anticipated to experience a life generally similar to the overall Mains.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 45-R3
Net Salv: -60%

Proposed Depreciation Parameters

ASL/Curve: 47-R4
Future Net Salv: -50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.13%	1.92%
Average Remaining Life	38.3%	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 378 .00 Measuring & Regulating Station Equipment - General

Historical Experience

Plant Statistics
Plant Balance = $2,140,309
Original Gross Additions = $2,708,505
Oldest Surviving Vintage = 1920
Retirements = $569,872 or 21.0% of historical additions.

Experience Bands 1920 – 2008 (Simulated) 40-R2

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-22%	-10%	- 4%	- 7%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -40%

Plant Considerations/Future Expectations

This account investment is applicable to the costs associated with measuring and regulating vaults and equipment located throughout the Company's distribution system. This class of property is impacted by system pressure upgrades/changes as well as by manufacture discontinued properties.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 40-R1
Net Salv: -30%

Proposed Depreciation Parameters

ASL/Curve: 40-R2
Future Net Salv: -30%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.14%	2.96%
Average Remaining Life	27.5 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

379.00 Measuring & Regulating Station Equipment – City Gate

Historical Experience

Plant Statistics	Plant Balance = $1,028,822 Original Gross Additions = $2,157,166 Oldest Surviving Vintage = 1951 Retirements = $458,632 or 21.3% of historical additions.
Experience Bands	1951 – 2008 (Simulated) 27-L0

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
0%	0%	0%	21%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
1%	0%	0%	0%

Forecasted Net Salvage: -9%

Plant Considerations/Future Expectations

This account investment is applicable to the costs associated with measuring and regulating vaults and equipment located throughout the Company's City Gate Stations. Similar to general M&R equipment, this class of property is impacted by system pressure upgrades/changes as well as by manufacture discontinued properties.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 35-R2.5
Net Salv: -15%

Proposed Depreciation Parameters

ASL/Curve: 27-L0
Future Net Salv: -15%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.14	3.54%
Average Remaining Life	16.0 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.10 Services – Steel

Historical Experience

Plant Statistics	Plant Balance = $7,285,188 Original Gross Additions = $54,121,206 (Total Account) Oldest Surviving Vintage = 1928 Retirements = $3,625,013 (Total Account) or 6.7% of historical additions.
Experience Bands	1920– 2008 (Simulated) 40-R3

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-234%	-240%	-243%	-88%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -210%

Plant Considerations/Future Expectations

This property group is comprised of the Company's investment and related experience of Steel Services. The older vintage investments within the property group are related to Bare Steel Service which routinely experience higher replacement rates.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 40-R2.5
Net Salv: -175%

Proposed Depreciation Parameters

ASL/Curve: 40-R3
Future Net Salv: -200%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	9.65%	5.66%
Average Remaining Life	13.4 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.20 Services – Plastic

Historical Experience

Plant Statistics	Plant Balance = $42,690,273 Original Gross Additions = $54,121,206 (Total Account) Oldest Surviving Vintage = 1969 Retirements = $3,625,013 (Total Account) or 6.7% of historical additions.
Experience Bands	1920 – 2008 (Simulated) 40-R3

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-234%	-240%	-243%	-88%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -210%

Plant Considerations/Future Expectations

This property group is comprised of the Company's investment and related experience of Plastic Services. The future service life of this asset class is anticipated to generally be reflective the recent experience.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 40-R3
Net Salv: -175%

Proposed Depreciation Parameters

ASL/Curve: 40-R3
Future Net Salv: -200%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	7.91%	5.66%
Average Remaining Life	29.0 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 380.30 Services – Farm & Fuel Lines

Historical Experience

Plant Statistics — Plant Balance = $248,640
Original Gross Additions = $54,121,206 (Total Account)
Oldest Surviving Vintage = 1977
Retirements = $3,625,013 (Total Account) or 6.7% of historical additions.

Experience Bands — Estimated 30-R1.5

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-234%	-240%	-243%	-88%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0	0%	0%	0%

Forecasted Net Salvage: -210%

Plant Considerations/Future Expectations

This property group is comprised of the Company's investment in a limited amount of Farm and Fuel service lines. The future service life of this asset class is anticipated to generally be reflective the recent experience.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 30-R1.5
Net Salv: -175%

Proposed Depreciation Parameters

ASL/Curve: 30-R1.5
Future Net Salv: -200%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	11.01%	5.66%
Average Remaining Life	17.9 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 381 Meters

Historical Experience

Plant Statistics   Plant Balance = $55,172,050
Original Gross Additions = $63,302,194
Oldest Surviving Vintage = 1956
Retirements = $7,690,772 or 12.1% of historical additions.

Experience Bands   1933 - 2008 (Simulated) 35-R4

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-25%	-18%	-9%	7%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
10%	15%	16%	0%

Forecasted Net Salvage: -19%

Plant Considerations/Future Expectations

While no specific consideration has been factored into the estimated average service life of meters, in future years the Company's Meter can be anticipated to be impact by Automated Meter Reading technology. It is anticipated that the Company will is investigate the benefits and cost of installing such a Meter system. Under a typical Meter upgrade model/program customer's Meters would routinely be replaced with new property to enhance the efficiency of the Meter reading task. Accordingly, the current service life being achieved by this property class can be anticipated to be materially impacted (shortened) in future years.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 35-R2.5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 35-R4
Future Net Salv: -15%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.53%	3.19%
Average Remaining Life	24.1 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 383.00 House Regulators

Historical Experience

Plant Statistics	Plant Balance = $5,555,208 Original Gross Additions = $6,567,312 Oldest Surviving Vintage = 1946 Retirements = $1,025,159 or 15.6% of historical additions.
Experience Bands	1946 – 2008 (Simulated) 40-R2

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
289%	866%	264%	20%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
285%.	358%	481%	692%

Forecasted Net Salvage: 691%

Plant Considerations/Future Expectations

The account contains the Company's investments related to the residential gas regulators located at the customer's location. It is believed that in more recent years not all retirements may have been reported. Research is being completed to identify any such not reported retirements.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve 35-R3
Net Salv: 10%

Proposed Depreciation Parameters

ASL/Curve: 40-R2
Future Net Salv: 10%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	1.77%	2.59%
Average Remaining Life	25.4 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 385.00 Ind. Meas. & Reg. Station Equipment

Historical Experience

Plant Statistics	Plant Balance = $875,377 Original Gross Additions = $895,516 Oldest Surviving Vintage = 1951 Retirements = $120,608 or 13.5% of historical additions.
Experience Bands	Estimated 35-R2

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
0%	0%	0%	-36%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
16%	12%	0%	0%

Forecasted Net Salvage: -13%

Plant Considerations/Future Expectations

The account contains the Company's investments related to the residential gas regulators located at the customer's location. Future activity is not anticipated to be materially different than historical experience.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 35-R2
Net Salv: -15%

Proposed Depreciation Parameters

ASL/Curve: 35-R2
Future Net Salv: -15%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.31%	3.04%
Average Remaining Life	23.3 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 386.10 Misc. Property on Customer Premise

Historical Experience

Plant Statistics	Plant Balance = $1,680 Original Gross Additions = $1,680 Oldest Surviving Vintage = 1997 Retirements - $0 or 0% of historical additions.
Experience Bands	Estimated 15-R3

Historic Net Salvage: N/A

Forecasted Net Salvage: N/A

Plant Considerations/Future Expectations

The account currently contains only a minimal investment.

Life Analysis Method: Simulated Plant Analysis Method

Average Remaining Life Development: Full Mortality

Current Depreciation Parameters

ASL/Curve: 15-R3
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 15-R3
Future Net Salv: 0%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.39%	5.19%
Average Remaining Life	5.1 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 386.20 CNG Refueling Station

Historical Experience

Plant Statistics	Plant Balance = $261,880 Original Gross Additions = $465,811 Oldest Surviving Vintage = 1992 Retirements - $174,931 or 37.6% of historical additions.
Experience Bands	Estimated 15-R3

Historic Net Salvage: (06-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	2006-2008
0%	0%	0%	0%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: 0%

Plant Considerations/Future Expectations

The account contains the Company's investments related to CNG refueling equipment. The property was placed into service within the more recent years. While retirements have only occurred during one year they have aggregated more than 37 percent of the originally installed plant.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 15-R3
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 15-R3
Future Net Salv: 0%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	0.27%	3.70%
Average Remaining Life	3.3 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 387.10 Cathodic Protection Equipment

Historical Experience

Plant Statistics	Plant Balance = $1,737,818 Original Gross Additions = $2,437,225 Oldest Surviving Vintage = 1969 Retirements = $714,543 or 29.3% of historical additions.
Experience Bands	Estimated 20-R1.5

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
0%	-1%	-2%	-1%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
1%	0%	1%	0%

Forecasted Net Salvage: -2%

Plant Considerations/Future Expectations

This account includes the cost related to cathodic protection equipment used to control corrosion of the Company's plant.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 20-R1.5
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 20-R1.5
Future Net Salv: 0%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.21%	5.75%
Average Remaining Life	10.0 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 387.20 Other Distribution Equipment

Historical Experience

Plant Statistics	Plant Balance = \$588,026 Original Gross Additions = \$456,584 Oldest Surviving Vintage = 1950 Retirements = \$764,016 or N/A of historical additions.
Experience Bands	Estimated 25-R3

Historic Net Salvage: (77-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1977-2008
0%	0%	0%	0.2%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
0%	0%	0%	0%

Forecasted Net Salvage: -0.3%

Plant Considerations/Future Expectations

This account includes the limited cost of non specifically classified equipment related to the distribution plant.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

AS/Curve: 25-R3
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 25-R3
Future Net Salv: 0%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	1.42%	0.99%
Average Remaining Life	13.8 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 390.00 Structures And Improvements

Historical Experience

Plant Statistics	Plant Balance = $5,835,295 Original Gross Additions = $7,544,536 Oldest Surviving Vintage = 1928 Retirements - $2,183,743 or 28.9% of historical additions.
Experience Bands	1928-2008 (Simulated) 31-R4
Historic Net Salvage:	(68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
-1%	108%	115%	62%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
80%	51%	100%	126%

Forecasted Net Salvage: 120%

Plant Considerations/Future Expectations

This investment is related to cost of various General related structures and improvements. Ongoing changes occur due to required component upgrades as well as changes in business environment conditions. End of life costs relative to rehabilitation or disposal is routinely experienced within this property class.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 35-R3
Net Salv: -10%

Proposed Depreciation Parameters

ASL/Curve: 31-R4
Future Net Salv: -10%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	3.46%	3.73%
Average Remaining Life	21.9 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 392.10 Transportation Equipment - Trailers

Historical Experience

Plant Statistics	Plant Balance = $397,060 Original Gross Additions = $265,847 Oldest Surviving Vintage = 1992 Retirements = $23,062 or 8.7% of historical additions.
Experience Bands	Estimated 8-R0.5

Historic Net Salvage: (96-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1996-2008
5%	32%	35%	20%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
13%	13%	27%	38%

Forecasted Net Salvage: 38%

Plant Considerations/Future Expectations

This account includes the cost related to trailers use by the Company's workforce.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 8-R3
Net Salv: 15%

Proposed Depreciation Parameters

ASL/Curve: 8-R0.5
Future Net Salv: 15%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	9.67%	4.36%
Average Remaining Life	5.6 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 392.20 Transportation Equipment – (Cars & Trucks)

Historical Experience

Plant Statistics	Plant Balance = $8,775,094 Original Gross Additions = $11,097,752 Oldest Surviving Vintage = 1997 Retirements = $7,705,514 or 69.4% of historical additions.
Experience Bands	1995-2008 (Simulated) 7-R3

Historic Net Salvage: (95-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1995-2008
20%	21%	21%	19%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
19%	19%	20%	22%

Forecasted Net Salvage: 22%

Plant Considerations/Future Expectations

This investment is related to investments in automobiles & trucks used to maintain the Company's operating property. The Company general vehicle policy is to replace transportation equipment in the 7-8 year life range.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 6-R3
Net Salv: 15%

Proposed Depreciation Parameters

ASL/Curve: 7-R3
Future Net Salv: 20%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	0.00%	21.13%
Average Remaining Life	3.5 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 396.10 Work Equipment - Trailers

Historical Experience

Plant Statistics — Plant Balance = $530,576
Original Gross Additions = $550,630
Oldest Surviving Vintage = 1992
Retirements = $63,724 or 11.6% of historical additions.

Experience Bands — Estimated 10-R2

Historic Net Salvage: (96-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1996-2008
3%	42%	19%	35%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
32%	32%	10%	29%

Forecasted Net Salvage: 29%

Plant Considerations/Future Expectations

This investment is related to investments in work trailers.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 10-R2
Net Salv: 35%

Proposed Depreciation Parameters

ASL/Curve: 10-R2
Future Net Salv: 20%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	6.02%	5.76%
Average Remaining Life	4.8 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 396.20 Power Operated Equipment

Historical Experience

Plant Statistics	Plant Balance = $6,142,234 Original Gross Additions = $28,265,694 Oldest Surviving Vintage = 1996 Retirements = $23,046,715 or 81.5% of historical additions.
Experience Bands	1963-2008 (Simulated) 4-L1

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
84%	86%	88%	81%

Gross Salvage Trend Analysis			
20 Year	15 Year	10 Year	5 Year
87%	79%	83%	93%

Forecasted Net Salvage: 93%

Plant Considerations/Future Expectations

This investment is related to investments in Power Operated equipment such as backhoes and other power equipment. Historic equipment vendor practices and trade in values have resulted in the Company replacing its equipment on quicker than usual basis.

Life Analysis Method: Simulated Plant Analysis Method

Current Depreciation Parameters

ASL/Curve: 7-R2
Net Salv: 60%

Proposed Depreciation Parameters

ASL/Curve: 4-L1
Future Net Salv: 80%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	0.95%	0%
Average Remaining Life	2.6 years	N/A

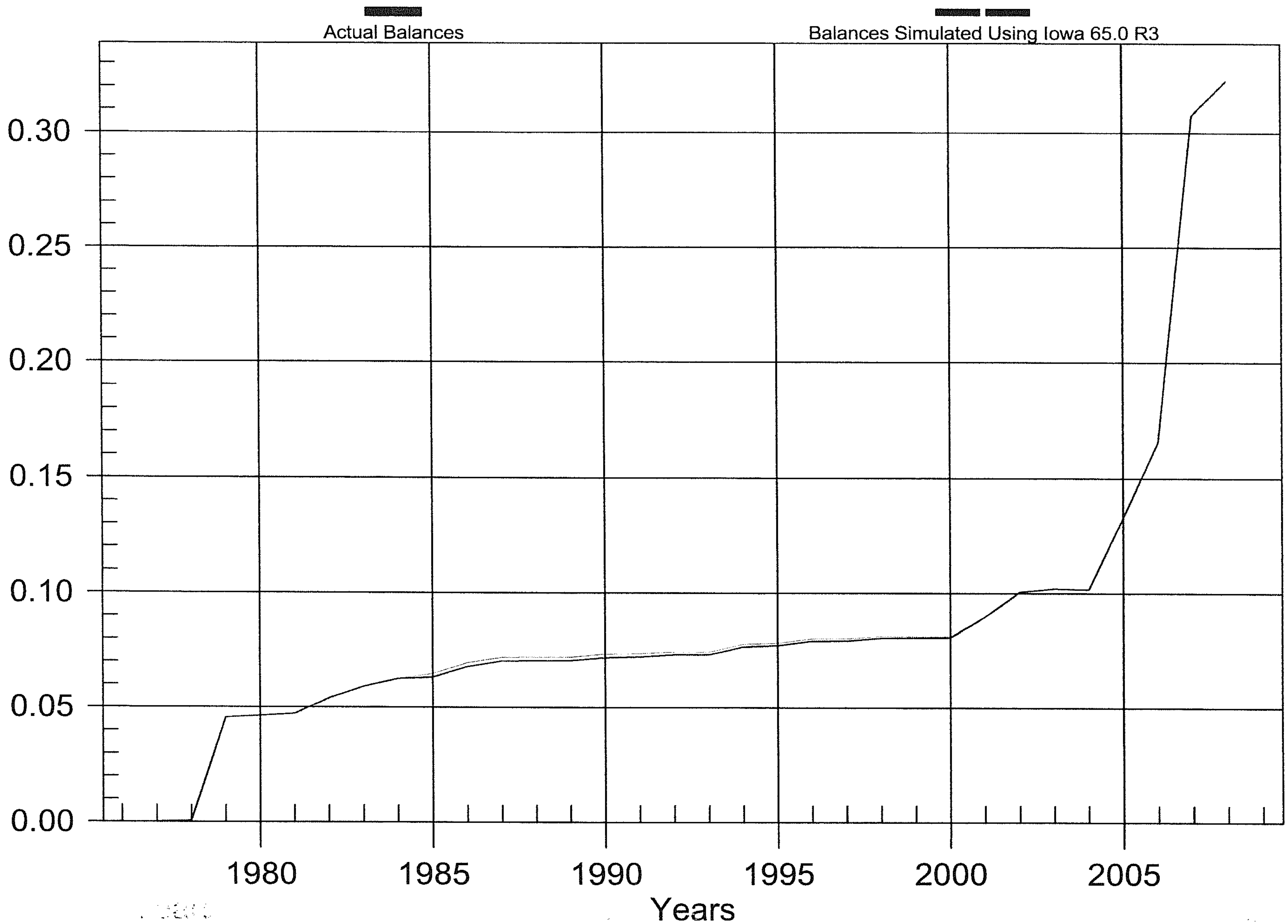
(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

Montana-Dakota Utilities Company

Gas Division

374.20 LAND RIGHTS

Actual And Simulated Balances 1977-2008

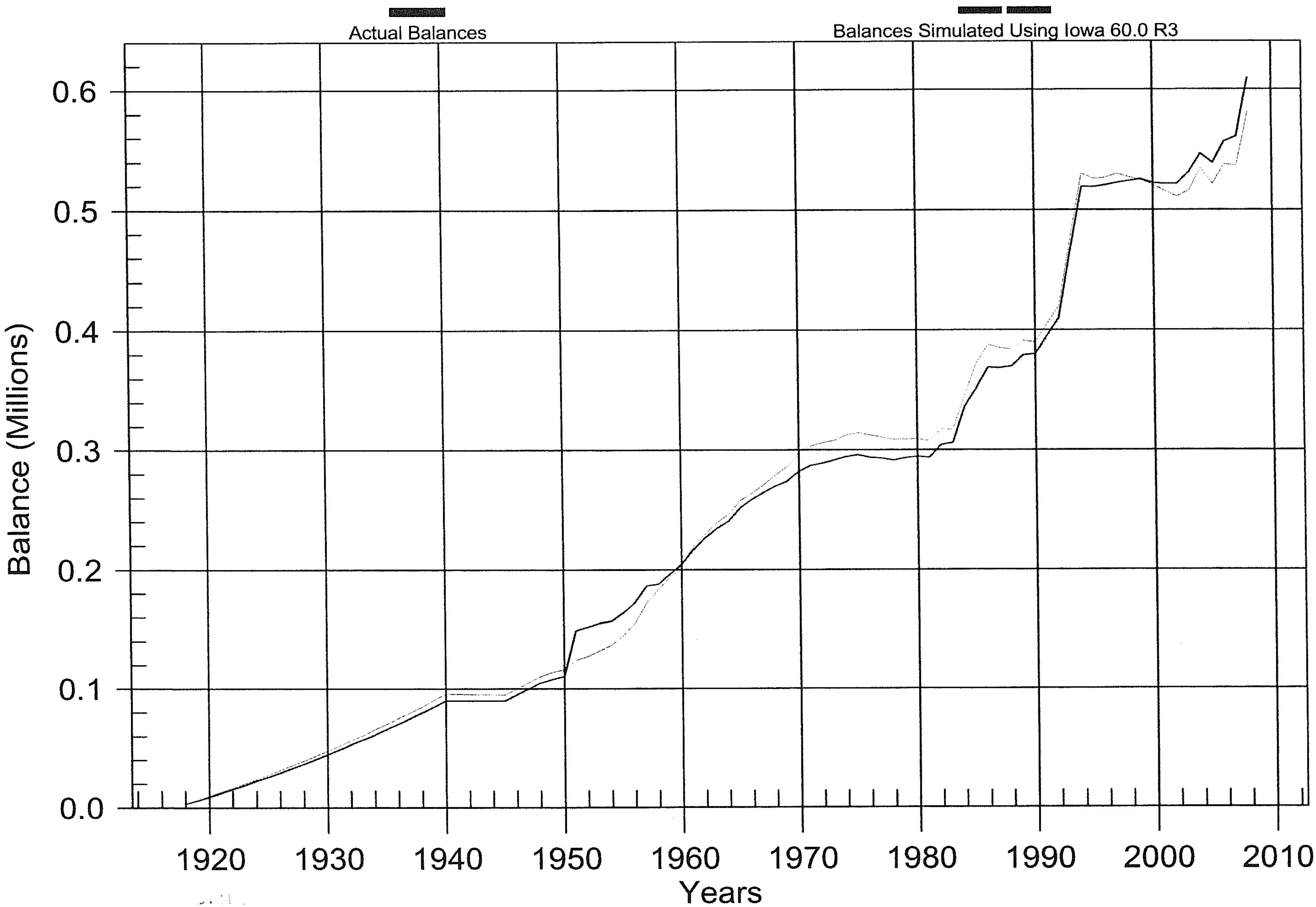


Montana-Dakota Utilities Company

Gas Division

375.00 STRUCTURES & IMPROVEMENTS

Actual And Simulated Balances 1918-2008

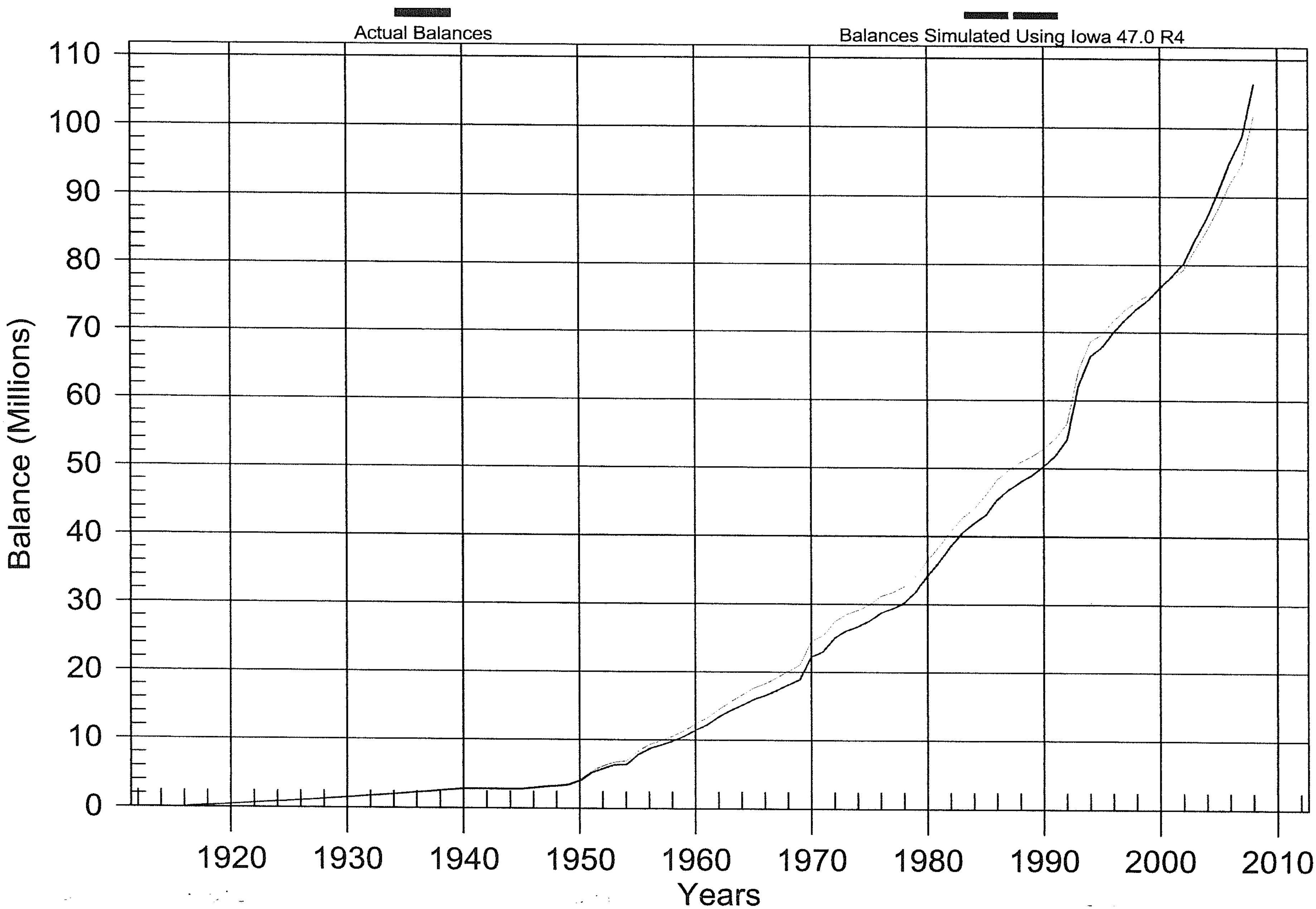


Montana-Dakota Utilities Company

Gas Division

376.00 MAINS

Actual And Simulated Balances 1916-2008

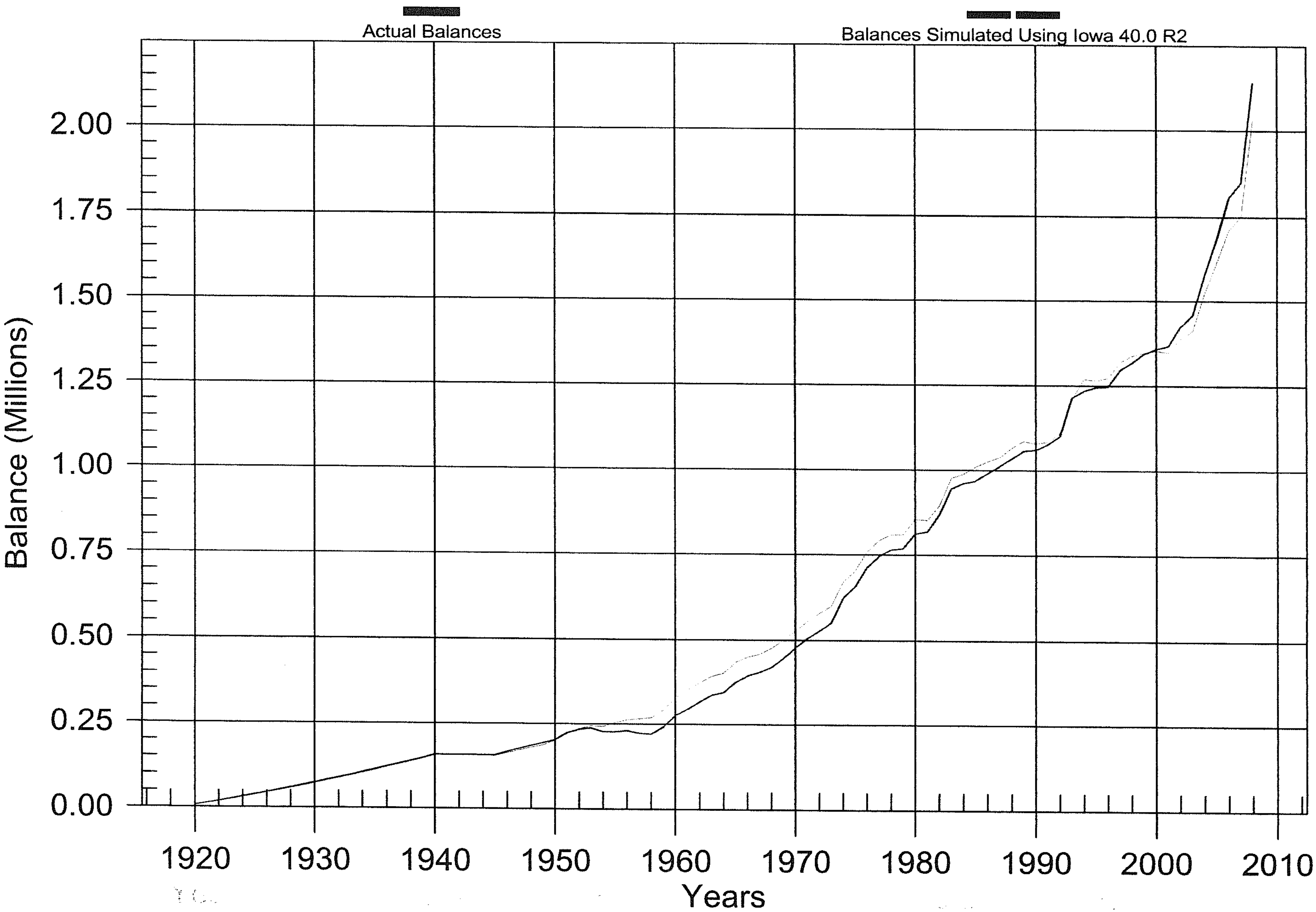


Montana-Dakota Utilities Company

Gas Division

378.00 MEAS. & REG. STATION EQUIP. - GENERAL

Actual And Simulated Balances 1920-2008

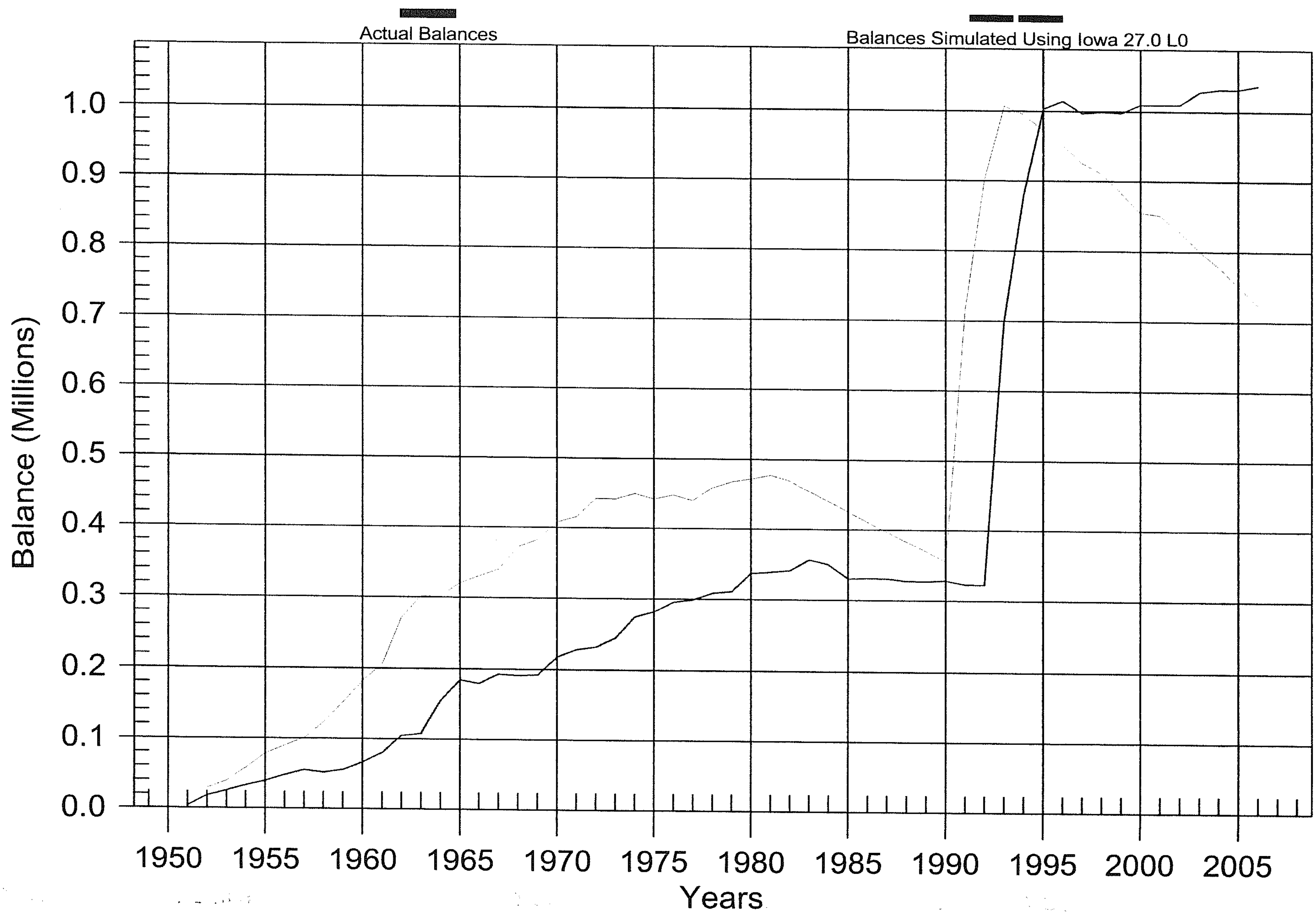


Montana-Dakota Utilities Company

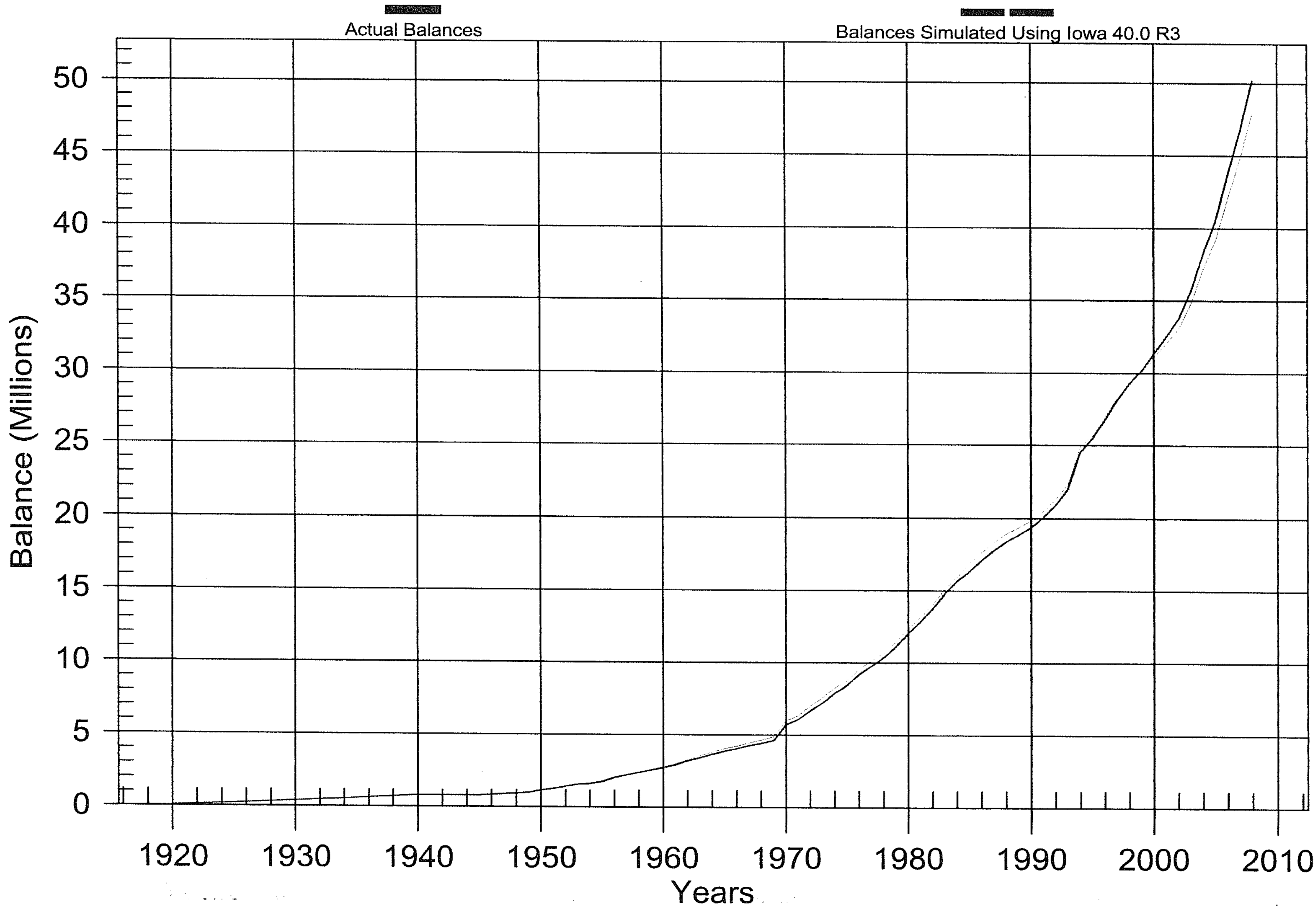
Gas Division

379.00 MEAS. & REG. STATION EQUIP. - CITY GATE

Actual And Simulated Balances 1951-2006



Montana-Dakota Utilities Company
Gas Division
380.00 SERVICES
Actual And Simulated Balances 1920-2008

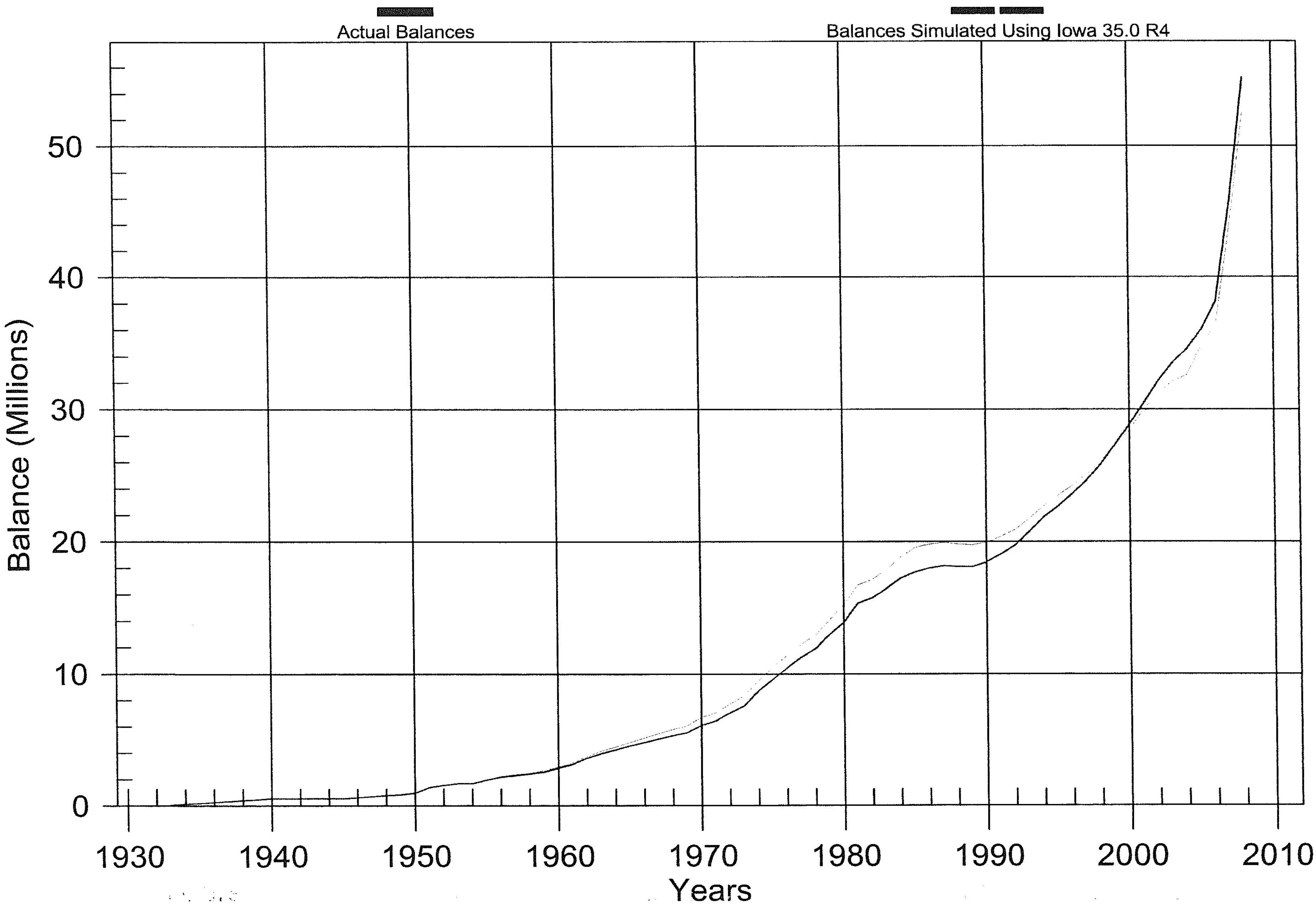


Montana-Dakota Utilities Company

Gas Division

381.00 METERS

Actual And Simulated Balances 1933-2008

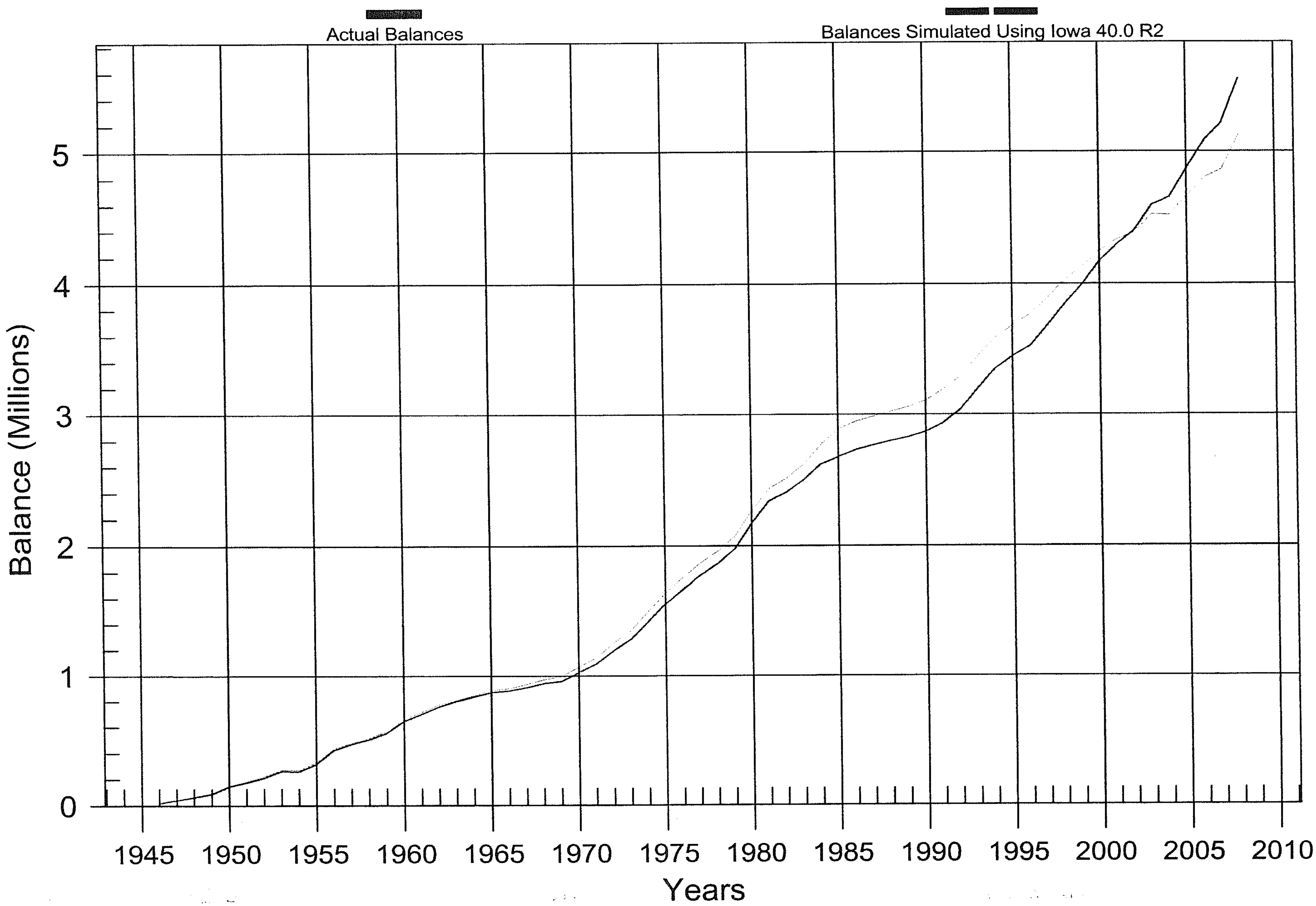


Montana-Dakota Utilities Company

Gas Division

383.00 HOUSE REGULATORS

Actual And Simulated Balances 1946-2008

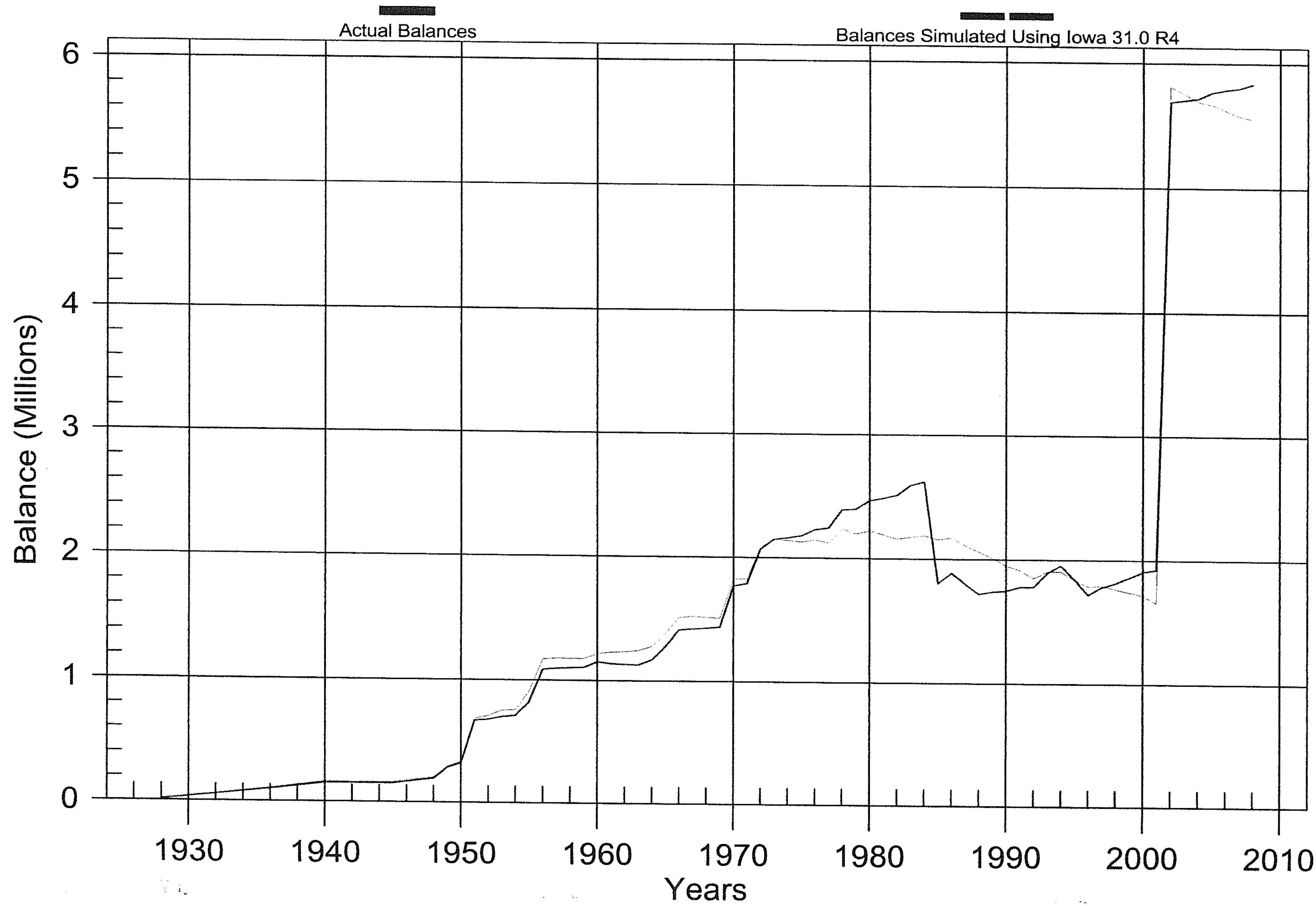


Montana-Dakota Utilities Company

Gas Division

390.00 STRUCTURES & IMPROVEMENTS

Actual And Simulated Balances 1928-2008

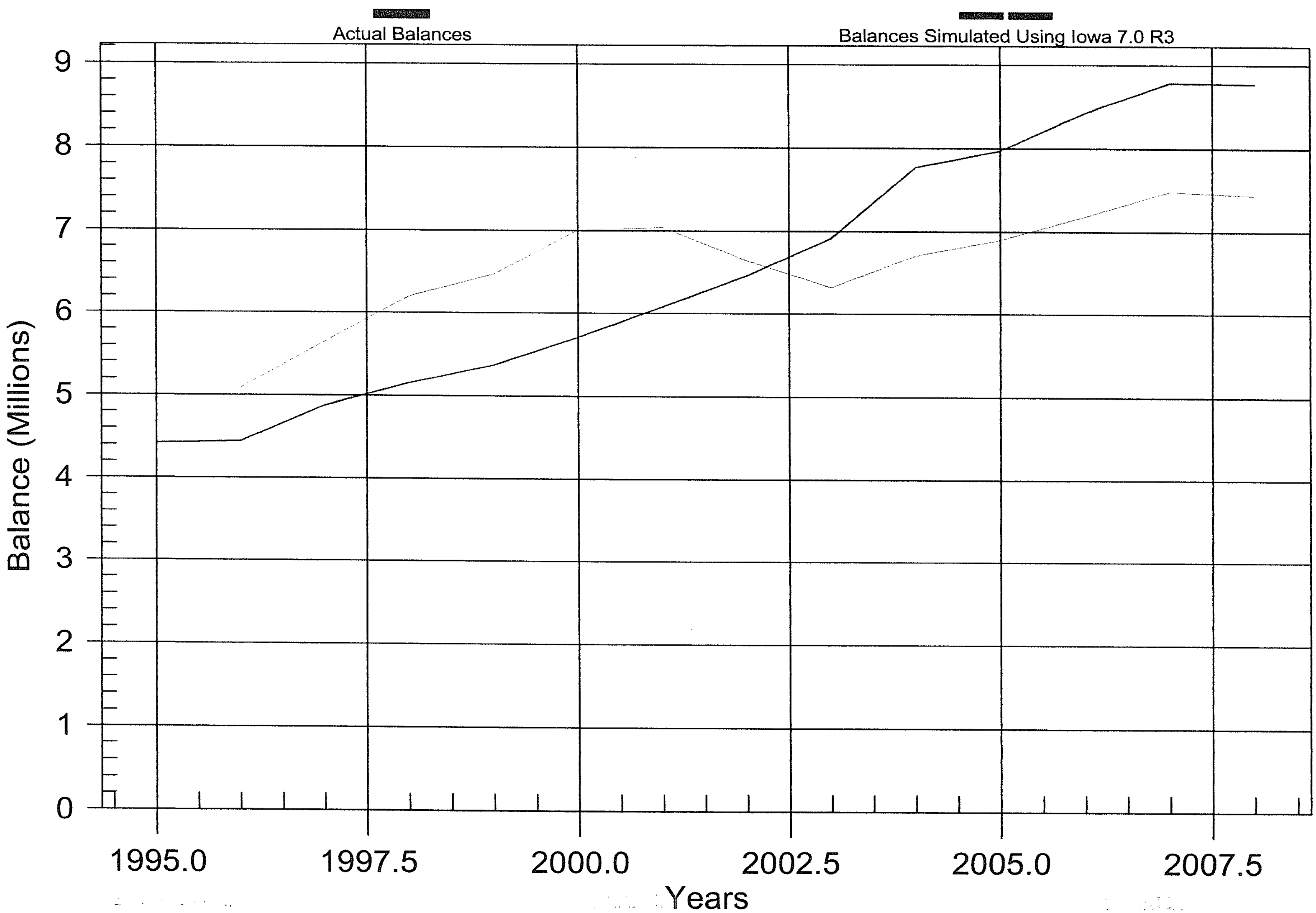


Montana-Dakota Utilities Company

Gas Division

392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Actual And Simulated Balances 1995-2008

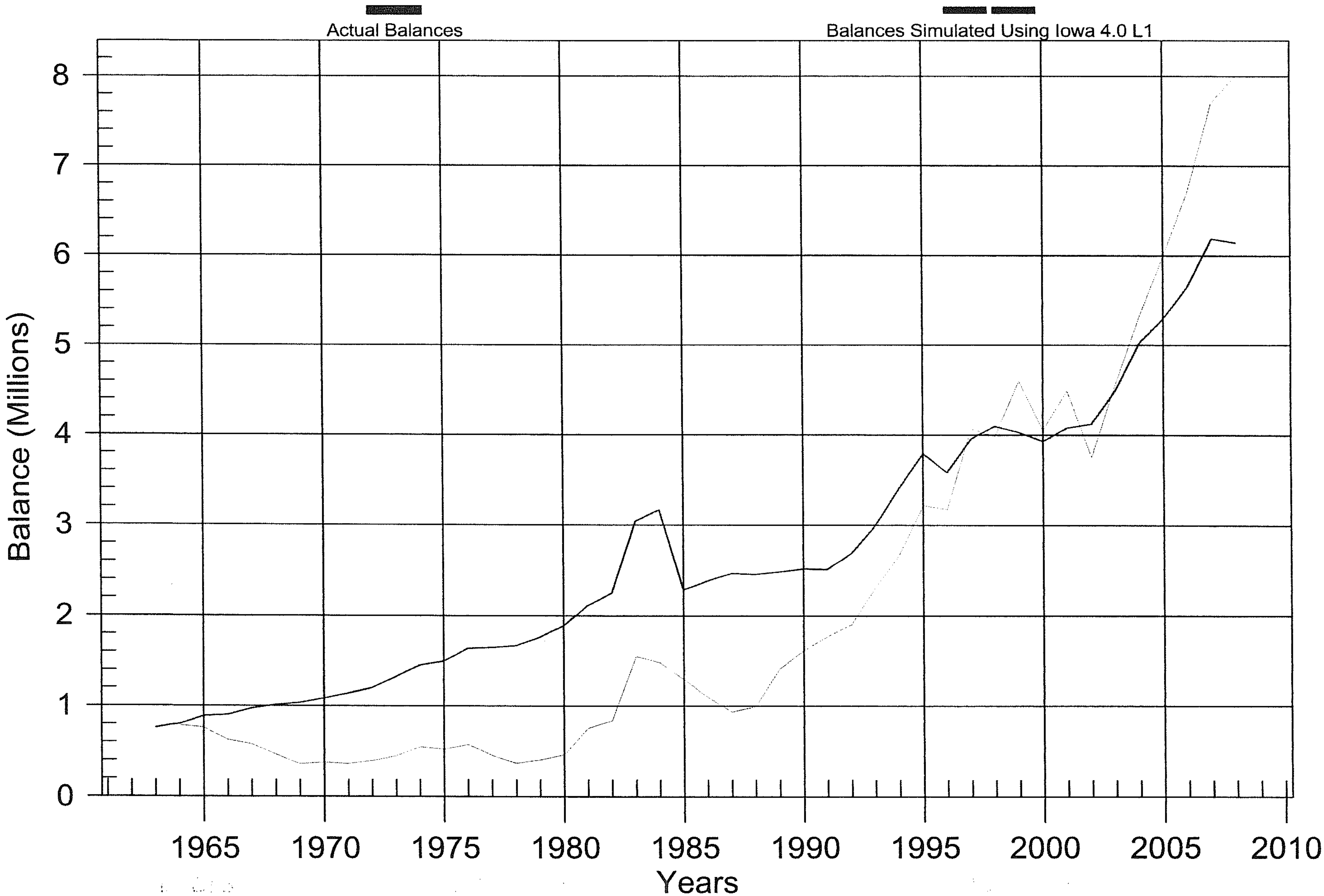


Montana-Dakota Utilities Company

Gas Division

396.20 POWER OPERATED EQUIPMENT

Actual And Simulated Balances 1963-2008



Montana-Dakota Utilities Company
Gas Division
374.20 LAND RIGHTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1977	123.84	65.00	1.91	35.80	68.21
1978	367.89	65.00	5.66	36.64	207.37
1979	44,010.92	65.00	677.09	37.49	25,383.04
1980	838.18	65.00	12.90	38.34	494.44
1981	880.70	65.00	13.55	39.21	531.22
1982	6,579.26	65.00	101.22	40.07	4,056.35
1983	4,970.03	65.00	76.46	40.95	3,131.26
1984	3,479.57	65.00	53.53	41.83	2,239.43
1985	2,255.99	65.00	34.71	42.72	1,482.84
1986	4,636.58	65.00	71.33	43.62	3,111.37
1987	2,388.48	65.00	36.75	44.52	1,635.95
1988	100.97	65.00	1.55	45.43	70.57
1989	50.96	65.00	0.78	46.34	36.33
1990	1,319.11	65.00	20.29	47.26	959.10
1991	374.48	65.00	5.76	48.18	277.60
1992	866.88	65.00	13.34	49.11	655.01
1994	3,384.15	65.00	52.06	50.99	2,654.53
1995	534.85	65.00	8.23	51.93	427.29
1996	1,974.62	65.00	30.38	52.88	1,606.33
1997	120.23	65.00	1.85	53.83	99.57
1998	1,198.38	65.00	18.44	54.78	1,010.03
1999	165.20	65.00	2.54	55.74	141.67
2001	8,907.38	65.00	137.04	57.67	7,903.04
2002	10,670.49	65.00	164.16	58.64	9,626.50
2003	1,465.36	65.00	22.54	59.61	1,343.90
2005	31,178.33	65.00	479.67	61.56	29,530.09
2006	32,961.57	65.00	507.10	62.54	31,715.52

Montana-Dakota Utilities Company

Gas Division

374.20 LAND RIGHTS

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2007	141,818.68	65.00	2,181.83	63.52	138,599.14
2008	15,054.53	65.00	231.61	64.51	14,940.46
Total	322,677.61	65.00	4,964.27	57.20	283,938.14

Composite Average Remaining Life ... 57.2 Years

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 60 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1918	2,549.67	60.00	42.49	2.64	112.23
1919	2,613.41	60.00	43.56	2.89	125.71
1920	2,678.75	60.00	44.65	3.14	140.19
1921	2,745.72	60.00	45.76	3.40	155.81
1922	2,814.36	60.00	46.91	3.65	171.44
1923	2,884.72	60.00	48.08	3.93	188.72
1924	2,956.84	60.00	49.28	4.17	205.58
1925	3,030.76	60.00	50.51	4.42	223.47
1926	3,106.53	60.00	51.78	4.68	242.33
1927	3,184.20	60.00	53.07	4.94	262.37
1928	3,263.80	60.00	54.40	5.20	282.74
1929	3,345.40	60.00	55.76	5.47	304.80
1930	3,429.03	60.00	57.15	5.72	326.95
1931	3,514.76	60.00	58.58	5.98	350.42
1932	3,602.63	60.00	60.04	6.25	375.26
1933	3,692.70	60.00	61.55	6.53	401.70
1934	3,785.01	60.00	63.08	6.80	429.21
1935	3,879.64	60.00	64.66	7.10	458.83
1936	3,976.63	60.00	66.28	7.39	489.59
1937	4,076.04	60.00	67.93	7.69	522.38
1938	4,177.94	60.00	69.63	8.00	557.33
1939	4,282.40	60.00	71.37	8.33	594.61
1940	4,389.45	60.00	73.16	8.67	634.12
1946	4,389.45	60.00	73.16	10.98	803.41
1947	4,389.46	60.00	73.16	11.42	835.47
1948	4,389.45	60.00	73.16	11.87	868.60
1949	2,946.37	60.00	49.11	12.34	606.14

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 60 *Survivor Curve: R3*

Year	*Original Cost*	*Avg. Service Life*	*Avg. Annual Accrual*	*Avg. Remaining Life*	*Future Annual Accruals*
(1)	*(2)*	*(3)*	*(4)*	*(5)*	*(6)*
1950	2,260.43	60.00	37.67	12.83	483.33
1951	6,436.86	60.00	107.28	13.33	1,430.00
1952	3,100.30	60.00	51.67	13.85	715.54
1953	3,872.92	60.00	64.55	14.38	928.08
1954	4,296.04	60.00	71.60	14.93	1,068.87
1955	6,514.69	60.00	108.58	15.49	1,682.20
1956	8,930.82	60.00	148.85	16.07	2,392.26
1957	14,470.07	60.00	241.17	16.66	4,018.73
1958	9,585.30	60.00	159.76	17.27	2,759.34
1959	8,520.71	60.00	142.01	17.89	2,540.69
1960	8,522.94	60.00	142.05	18.53	2,631.82
1961	13,248.79	60.00	220.81	19.18	4,234.46
1962	8,989.91	60.00	149.83	19.84	2,972.32
1963	8,131.68	60.00	135.53	20.51	2,779.57
1964	6,371.60	60.00	106.19	21.20	2,250.79
1965	9,992.23	60.00	166.54	21.89	3,645.32
1966	5,828.89	60.00	97.15	22.60	2,195.38
1967	6,612.01	60.00	110.20	23.32	2,569.62
1968	7,048.88	60.00	117.48	24.05	2,825.07
1969	6,707.67	60.00	111.79	24.78	2,770.83
1970	10,359.50	60.00	172.66	25.54	4,408.85
1971	5,664.76	60.00	94.41	26.29	2,482.27
1972	3,152.21	60.00	52.54	27.06	1,421.73
1973	2,925.15	60.00	48.75	27.84	1,357.28
1974	4,943.72	60.00	82.40	28.63	2,358.75
1975	2,684.77	60.00	44.75	29.42	1,316.52
1979	1,871.19	60.00	31.19	32.69	1,019.54

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 60 *Survivor Curve: R3*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1980	1,902.46	60.00	31.71	33.53	1,063.15
1981	547.81	60.00	9.13	34.37	313.85
1982	10,227.11	60.00	170.45	35.23	6,004.86
1983	1,482.50	60.00	24.71	36.09	891.69
1984	24,793.29	60.00	413.22	36.96	15,272.14
1985	24,176.80	60.00	402.95	37.84	15,245.69
1986	15,234.12	60.00	253.90	38.72	9,830.83
1987	476.01	60.00	7.93	39.61	314.23
1988	1,364.46	60.00	22.74	40.51	921.15
1989	8,732.82	60.00	145.55	41.41	6,026.85
1990	1,621.38	60.00	27.02	42.32	1,143.59
1991	14,966.44	60.00	249.44	43.24	10,784.66
1992	15,110.26	60.00	251.84	44.16	11,120.15
1993	48,046.30	60.00	800.77	45.08	36,102.18
1994	47,764.38	60.00	796.07	46.02	36,633.27
1996	3,737.66	60.00	62.29	47.90	2,983.78
1997	6,437.20	60.00	107.29	48.85	5,240.52
1998	1,253.75	60.00	20.90	49.80	1,040.57
1999	1,684.23	60.00	28.07	50.75	1,424.68
2000	552.36	60.00	9.21	51.71	476.08
2003	8,264.23	60.00	137.74	54.62	7,522.56
2004	19,358.84	60.00	322.65	55.59	17,935.56
2006	21,838.49	60.00	363.98	57.54	20,944.38
2007	4,224.14	60.00	70.40	58.52	4,120.23
2008	50,374.93	60.00	839.58	59.51	49,961.50

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **60** *Survivor Curve:* **R3**

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
Total	609,311.13	60.00	10,155.19	33.01	335,246.70

Composite Average Remaining Life ... 33.0 Years

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve: R4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1904	469.74	0.00	0.00	0.00	0.00
1905	755.55	0.00	0.00	0.00	0.00
1926	0.46	0.00	0.00	0.00	0.00
1927	7.90	0.00	0.00	0.00	0.00
1928	37.89	0.00	0.00	0.00	0.00
1929	111.24	0.00	0.00	0.00	0.00
1930	253.98	0.00	0.00	0.00	0.00
1931	493.63	0.00	0.00	0.00	0.00
1932	703.03	0.00	0.00	0.00	0.00
1933	655.15	0.00	0.00	0.00	0.00
1934	450.01	0.00	0.00	0.00	0.00
1935	418.47	0.00	0.00	0.00	0.00
1936	2,005.57	0.00	0.00	0.00	0.00
1937	4,246.91	47.00	90.36	0.50	45.18
1938	1,424.88	47.00	30.32	0.51	15.35
1939	2,306.00	47.00	49.06	0.61	29.73
1940	923.00	47.00	19.64	0.76	14.91
1946	24,144.41	47.00	513.71	2.04	1,047.40
1947	34,507.81	47.00	734.20	2.29	1,678.51
1948	39,544.48	47.00	841.36	2.54	2,136.18
1949	46,827.51	47.00	996.32	2.80	2,786.18
1950	218,884.19	47.00	4,657.06	3.05	14,192.90
1951	476,663.48	47.00	10,141.66	3.32	33,629.07
1952	296,702.94	47.00	6,312.76	3.59	22,658.37
1953	270,639.75	47.00	5,758.23	3.87	22,279.19
1954	74,257.30	47.00	1,579.93	4.16	6,568.24
1955	731,467.72	47.00	15,562.97	4.46	69,354.32

Montana-Dakota Utilities Company

Gas Division

376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1956	538,098.79	47.00	11,448.78	4.77	54,600.66
1957	314,770.47	47.00	6,697.17	5.10	34,146.89
1958	391,106.28	47.00	8,321.32	5.45	45,327.76
1959	546,461.29	47.00	11,626.71	5.82	67,689.88
1960	720,787.84	47.00	15,335.74	6.22	95,445.84
1961	630,728.66	47.00	13,419.61	6.66	89,315.49
1962	927,542.70	47.00	19,734.73	7.12	140,509.86
1963	863,732.22	47.00	18,377.08	7.62	140,005.30
1964	826,387.83	47.00	17,582.53	8.15	143,331.25
1965	840,851.87	47.00	17,890.27	8.72	155,995.76
1966	599,061.81	47.00	12,745.86	9.32	118,841.55
1967	846,189.44	47.00	18,003.83	9.95	179,174.21
1968	1,040,360.26	47.00	22,135.08	10.60	234,704.74
1969	938,031.03	47.00	19,957.89	11.27	224,987.59
1970	3,206,435.77	47.00	68,221.29	11.96	815,800.21
1971	777,937.31	47.00	16,551.68	12.66	209,501.66
1972	819,681.51	47.00	17,439.84	13.37	233,197.72
1973	904,826.77	47.00	19,251.42	14.10	271,466.59
1974	441,083.34	47.00	9,384.65	14.85	139,359.15
1975	56,815.00	47.00	1,208.82	15.61	18,871.56
1976	719,735.33	47.00	15,313.35	16.39	250,979.40
1977	398,931.83	47.00	8,487.82	17.18	145,850.76
1978	356,063.94	47.00	7,575.75	17.99	136,312.37
1979	692,815.95	47.00	14,740.60	18.82	277,394.72
1980	838,852.11	47.00	17,847.72	19.66	350,860.12
1981	1,021,359.93	47.00	21,730.82	20.51	445,767.12
1982	1,208,817.07	47.00	25,719.23	21.38	549,978.60

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1983	965,584.46	47.00	20,544.12	22.27	457,429.93
1984	320,731.56	47.00	6,824.00	23.16	158,042.93
1985	788,387.51	47.00	16,774.02	24.07	403,676.48
1986	1,209,008.32	47.00	25,723.30	24.98	642,621.61
1987	344,343.54	47.00	7,326.38	25.91	189,815.96
1988	568,793.49	47.00	12,101.86	26.84	324,864.86
1989	444,873.54	47.00	9,465.29	27.79	263,033.78
1990	442,123.14	47.00	9,406.77	28.74	270,359.95
1991	545,918.18	47.00	11,615.15	29.70	344,963.68
1992	632,954.05	47.00	13,466.96	30.66	412,950.34
1993	1,087,025.48	47.00	23,127.95	31.63	731,625.84
1994	385,968.63	47.00	8,212.01	32.61	267,780.87
1995	93,201.40	47.00	1,982.99	33.59	66,602.95
1996	160,286.25	47.00	3,410.31	34.57	117,892.68
1997	103,532.09	47.00	2,202.79	35.56	78,320.69
1998	263,997.66	47.00	5,616.91	36.54	205,260.65
1999	411,147.59	47.00	8,747.73	37.53	328,333.80
2000	415,155.29	47.00	8,832.99	38.53	340,297.94
2001	112,871.05	47.00	2,401.49	39.52	94,905.47
2002	177,935.15	47.00	3,785.81	40.51	153,380.27
2003	1,137,902.51	47.00	24,210.43	41.51	1,004,988.12
2004	1,103,475.58	47.00	23,477.95	42.51	997,988.29
2005	1,561,295.64	47.00	33,218.69	43.51	1,445,185.25
2006	368,109.51	47.00	7,832.03	44.50	348,551.72
2007	513,100.14	47.00	10,916.90	45.50	496,740.71
2008	4,120,958.34	47.00	87,679.00	46.50	4,077,155.34

Montana-Dakota Utilities Company
Gas Division
376.10 MAINS - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	41,975,049.45	39.36	892,940.98	22.36	19,968,622.34

Composite Average Remaining Life ... 22.3 Years

Montana-Dakota Utilities Company
Gas Division
376.20 MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1969	135,279.43	47.00	2,878.25	11.27	32,446.89
1970	375,086.60	47.00	7,980.48	11.96	95,431.73
1971	142,625.39	47.00	3,034.55	12.66	38,409.59
1972	1,294,061.62	47.00	27,532.92	13.37	368,157.89
1973	297,950.57	47.00	6,339.30	14.10	89,391.28
1974	65,675.19	47.00	1,397.33	14.85	20,749.91
1975	893,346.54	47.00	19,007.16	15.61	296,732.33
1976	652,826.63	47.00	13,889.78	16.39	227,647.62
1977	318,479.60	47.00	6,776.09	17.18	116,437.16
1978	523,726.09	47.00	11,142.99	17.99	200,498.66
1979	1,099,370.09	47.00	23,390.60	18.82	440,173.84
1980	1,499,614.40	47.00	31,906.34	19.66	627,232.00
1981	1,106,155.39	47.00	23,534.96	20.51	482,775.64
1982	1,140,141.23	47.00	24,258.06	21.38	518,732.98
1983	1,178,844.50	47.00	25,081.52	22.27	558,458.41
1984	1,247,938.59	47.00	26,551.59	23.16	614,931.28
1985	1,266,384.82	47.00	26,944.06	24.07	648,424.48
1986	1,207,695.76	47.00	25,695.37	24.98	641,923.95
1987	1,245,600.97	47.00	26,501.86	25.91	686,625.19
1988	798,772.36	47.00	16,994.97	26.84	456,216.67
1989	616,172.76	47.00	13,109.91	27.79	364,315.32
1990	900,428.29	47.00	19,157.84	28.74	550,615.25
1991	1,258,329.77	47.00	26,772.68	29.70	795,133.93
1992	1,909,825.75	47.00	40,634.14	30.66	1,246,003.85
1993	6,716,425.25	47.00	142,901.10	31.63	4,520,510.63
1994	4,144,868.16	47.00	88,187.72	32.61	2,875,664.84
1995	1,260,540.60	47.00	26,819.72	33.59	900,798.89

Montana-Dakota Utilities Company
Gas Division
376.20 MAINS - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve: R4*

Year *(1)*	*Original Cost* *(2)*	*Avg. Service Life* *(3)*	*Avg. Annual Accrual* *(4)*	*Avg. Remaining Life* *(5)*	*Future Annual Accruals* *(6)*
1996	2,326,335.52	47.00	49,495.96	34.57	1,711;050.83
1997	1,961,601.15	47.00	41,735.74	35.56	1,483,925.97
1998	1,434,972.07	47.00	30,530.99	36.54	1,115,704.21
1999	1,002,858.81	47.00	21,337.19	37.53	800,861.91
2000	1,465,621.71	47.00	31,183.10	38.53	1,201,352.99
2001	1,596,263.87	47.00	33,962.69	39.52	1,342,188.03
2002	1,642,908.92	47.00	34,955.13	40.51	1,416,189.02
2003	3,159,607.85	47.00	67,224.96	41.51	2,790,545.16
2004	2,466,222.75	47.00	52,472.25	42.51	2,230,462.98
2005	3,699,727.95	47.00	78,716.75	43.51	3,424,586.68
2006	3,378,408.81	47.00	71,880.25	44.50	3,198,912.73
2007	3,274,264.95	47.00	69,664.45	45.50	3,169,869.93
2008	3,230,998.08	47.00	68,743.89	46.50	3,196,654.76
Total	63,935,958.79	47.00	1,360,324.62	33.45	45,496,745.44

Composite Average Remaining Life ... 33.4 Years

Montana-Dakota Utilities Company
Gas Division
376.30 MAINS - VALVES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1904	627.59	0.00	0.00	0.00	0.00
1977	1,442.20	40.00	36.05	14.21	512.47
1978	1,809.82	40.00	45.25	14.85	671.99
1979	8,309.96	40.00	207.75	15.50	3,221.12
1980	3,512.48	40.00	87.81	16.18	1,420.39
1981	2,710.94	40.00	67.77	16.86	1,142.60
1982	10,041.69	40.00	251.04	17.56	4,408.04
1983	1,791.09	40.00	44.78	18.27	818.13
1984	8,052.13	40.00	201.30	19.00	3,824.43
1985	38,658.45	40.00	966.46	19.74	19,075.05
1986	10,734.69	40.00	268.37	20.49	5,498.79
1987	28,426.45	40.00	710.66	21.25	15,103.91
1988	24,014.92	40.00	600.37	22.03	13,226.32
1989	8,493.27	40.00	212.33	22.82	4,844.81
1990	5,192.49	40.00	129.81	23.62	3,065.75
1991	3,640.35	40.00	91.01	24.43	2,222.98
1992	13,194.19	40.00	329.85	25.25	8,327.86
1993	142,145.32	40.00	3,553.62	26.08	92,668.81
1994	17,817.20	40.00	445.43	26.92	11,990.28
1995	4,300.00	40.00	107.50	27.77	2,985.08
1997	5,405.53	40.00	135.14	29.50	3,986.05
1999	36,828.93	40.00	920.72	31.26	28,780.04
2000	8,767.06	40.00	219.18	32.15	7,046.81
2001	4,650.56	40.00	116.26	33.05	3,842.65
2004	28,251.97	40.00	706.30	35.79	25,280.14
2005	495.32	40.00	12.38	36.72	454.68
2008	28,013.49	40.00	700.33	39.53	27,682.69

Montana-Dakota Utilities Company
Gas Division
376.30 MAINS - VALVES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve: R2.5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	447,328.09	38.52	11,167.47	26.16	292,101.86

Composite Average Remaining Life ... 26.1 Years

Montana-Dakota Utilities Company
Gas Division
376.40 MAINS - MANHOLES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 47 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1960	9.90	47.00	0.21	6.22	1.31
1978	3,706.52	47.00	78.86	17.99	1,418.97
1979	1,211.43	47.00	25.77	18.82	485.04
1980	7,430.06	47.00	158.08	19.66	3,107.71
1981	4,708.73	47.00	100.18	20.51	2,055.10
1982	10,590.76	47.00	225.33	21.38	4,818.51
1983	4,593.08	47.00	97.72	22.27	2,175.90
1984	2,952.00	47.00	62.81	23.16	1,454.62
1985	5,397.11	47.00	114.83	24.07	2,763.47
1986	1,716.97	47.00	36.53	24.98	912.62
1987	3,512.13	47.00	74.73	25.91	1,936.03
1988	3,739.38	47.00	79.56	26.84	2,135.74
1990	9,279.86	47.00	197.44	28.74	5,674.67
1991	1,140.52	47.00	24.27	29.70	720.69
1993	4,344.30	47.00	92.43	31.63	2,923.94
1995	2,299.05	47.00	48.92	33.59	1,642.93
1996	3,287.49	47.00	69.95	34.57	2,417.99
Total	69,919.29	47.00	1,487.63	24.63	36,645.24

Composite Average Remaining Life ... 24.6 *Years*

Montana-Dakota Utilities Company
Gas Division
376.50 MAINS - BRIDGE & RIVER CROSSINGS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *47* *Survivor Curve:* *R4*

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
1995	8,923.21	47.00	189.85	33.59	6,376.64
1996	39.60	47.00	0.84	34.57	29.13
1998	1,723.00	47.00	36.66	36.54	1,339.65
2002	2,617.45	47.00	55.69	40.51	2,256.24
2006	6,514.77	47.00	138.61	44.50	6,168.64
Total	19,818.03	47.00	421.66	38.35	16,170.30

Composite Average Remaining Life ... 38.3 Years

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1920	5.33	0.00	0.00	0.00	0.00
1921	5.46	0.00	0.00	0.00	0.00
1922	5.60	0.00	0.00	0.00	0.00
1923	5.74	0.00	0.00	0.00	0.00
1924	5.88	0.00	0.00	0.00	0.00
1925	6.03	0.00	0.00	0.00	0.00
1926	6.18	0.00	0.00	0.00	0.00
1927	6.34	0.00	0.00	0.00	0.00
1928	6.49	0.00	0.00	0.00	0.00
1929	6.66	0.00	0.00	0.00	0.00
1930	6.82	0.00	0.00	0.00	0.00
1931	6.99	0.00	0.00	0.00	0.00
1932	7.17	0.00	0.00	0.00	0.00
1933	7.35	0.00	0.00	0.00	0.00
1934	7.53	0.00	0.00	0.00	0.00
1935	7.72	40.00	0.19	0.50	0.10
1936	7.91	40.00	0.20	0.57	0.11
1937	8.11	40.00	0.20	0.81	0.16
1938	8.31	40.00	0.21	1.03	0.21
1939	8.52	40.00	0.21	1.29	0.28
1940	8.73	40.00	0.22	1.55	0.34
1946	489.20	40.00	12.23	3.23	39.44
1947	604.62	40.00	15.12	3.52	53.16
1948	734.64	40.00	18.37	3.80	69.84
1949	879.71	40.00	21.99	4.10	90.08
1950	1,600.14	40.00	40.00	4.38	175.38
1951	2,849.35	40.00	71.23	4.68	333.31

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1952	2,115.27	40.00	52.88	4.97	262.91
1953	1,717.67	40.00	42.94	5.27	226.39
1954	108.96	40.00	2.72	5.57	15.18
1955	3,142.11	40.00	78.55	5.88	462.10
1956	2,639.38	40.00	65.98	6.20	408.85
1957	1,503.55	40.00	37.59	6.52	245.08
1958	1,714.37	40.00	42.86	6.85	293.62
1959	8,319.67	40.00	207.99	7.19	1,496.10
1960	14,130.63	40.00	353.26	7.54	2,665.36
1961	10,145.84	40.00	253.64	7.91	2,006.20
1962	10,044.22	40.00	251.10	8.29	2,080.57
1963	10,161.65	40.00	254.04	8.68	2,203.87
1964	6,445.78	40.00	161.14	9.08	1,462.91
1965	19,082.02	40.00	477.05	9.50	4,529.62
1966	10,303.98	40.00	257.60	9.93	2,557.06
1967	8,379.44	40.00	209.48	10.37	2,172.78
1968	12,799.00	40.00	319.97	10.83	3,466.26
1969	18,931.14	40.00	473.28	11.31	5,351.75
1970	21,037.63	40.00	525.94	11.80	6,205.42
1971	22,575.80	40.00	564.39	12.30	6,943.96
1972	21,137.04	40.00	528.42	12.82	6,776.63
1973	19,906.67	40.00	497.66	13.36	6,648.06
1974	59,348.43	40.00	1,483.70	13.91	20,636.61
1975	30,705.56	40.00	767.63	14.47	11,109.40
1976	50,457.18	40.00	1,261.42	15.05	18,986.18
1977	34,819.04	40.00	870.47	15.64	13,616.90
1978	22,058.32	40.00	551.45	16.25	8,961.25

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1979	7,819.46	40.00	195.49	16.87	3,297.71
1980	47,248.23	40.00	1,181.20	17.50	20,674.82
1981	7,681.73	40.00	192.04	18.15	3,485.31
1982	47,423.38	40.00	1,185.58	18.81	22,298.75
1983	84,198.01	40.00	2,104.94	19.48	41,002.03
1984	22,208.23	40.00	555.20	20.16	11,194.66
1985	31,853.53	40.00	796.33	20.86	16,609.82
1986	26,322.27	40.00	658.05	21.57	14,191.25
1987	25,326.71	40.00	633.16	22.28	14,108.86
1988	40,505.08	40.00	1,012.62	23.01	23,303.53
1989	33,013.57	40.00	825.33	23.75	19,603.77
1990	6,910.53	40.00	172.76	24.50	4,233.32
1991	21,678.77	40.00	541.97	25.26	13,692.23
1992	39,095.68	40.00	977.39	26.04	25,446.74
1993	119,100.20	40.00	2,977.49	26.82	79,843.13
1994	74,508.87	40.00	1,862.71	27.61	51,422.75
1995	13,568.57	40.00	339.21	28.41	9,635.47
1996	25,376.57	40.00	634.41	29.21	18,534.06
1997	65,941.20	40.00	1,648.52	30.03	49,507.78
1998	38,354.50	40.00	958.86	30.86	29,588.73
1999	29,411.54	40.00	735.28	31.69	23,302.99
2000	26,311.25	40.00	657.78	32.54	21,401.32
2001	17,102.56	40.00	427.56	33.39	14,274.66
2002	62,899.76	40.00	1,572.49	34.25	53,850.16
2003	45,097.40	40.00	1,127.43	35.11	39,585.18
2004	137,137.70	40.00	3,428.42	35.98	123,371.60
2005	115,007.32	40.00	2,875.17	36.87	105,993.53

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **40** *Survivor Curve:* **R2**

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2006	122,689.53	40.00	3,067.22	37.75	115,796.90
2007	66,813.13	40.00	1,670.32	38.65	64,552.53
2008	308,670.43	40.00	7,716.72	39.55	305,178.67
Total	2,140,308.59	32.86	53,505.03	27.50	1,471,535.68

Composite Average Remaining Life ... 27.5 *Years*

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 27 *Survivor Curve:* L0

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1951	4,763.00	27.00	176.41	8.42	1,485.11
1952	11,605.70	27.00	429.85	8.60	3,697.90
1953	9,220.02	27.00	341.49	8.79	3,002.26
1954	10,450.11	27.00	387.05	8.98	3,475.87
1955	7,367.76	27.00	272.88	9.17	2,503.00
1956	13,355.52	27.00	494.66	9.37	4,633.65
1957	14,707.12	27.00	544.72	9.57	5,210.95
1958	8,630.30	27.00	319.65	9.77	3,121.82
1959	8,975.93	27.00	332.45	9.97	3,314.48
1960	16,459.18	27.00	609.61	10.18	6,204.45
1961	21,671.86	27.00	802.67	10.39	8,337.23
1962	22,845.37	27.00	846.14	10.60	8,968.53
1963	19,139.82	27.00	708.89	10.82	7,667.88
1964	47,586.96	27.00	1,762.50	11.04	19,449.97
1965	24,797.89	27.00	918.45	11.26	10,339.80
1966	3,421.68	27.00	126.73	11.48	1,455.38
1967	17,749.93	27.00	657.41	11.71	7,701.35
1968	11,464.28	27.00	424.61	11.95	5,073.09
1969	12,112.73	27.00	448.63	12.18	5,466.40
1970	27,389.11	27.00	1,014.43	12.43	12,605.95
1971	13,097.20	27.00	485.09	12.67	6,146.70
1972	23,744.65	27.00	879.44	12.92	11,362.57
1973	12,291.58	27.00	455.25	13.17	5,997.20
1974	25,335.72	27.00	938.37	13.43	12,603.66
1975	7,402.42	27.00	274.17	13.69	3,754.18
1976	13,088.27	27.00	484.76	13.96	6,766.88
1977	3,225.52	27.00	119.47	14.23	1,700.08

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 27 *Survivor Curve:* L0

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1978	12,328.86	27.00	456.63	14.51	6,623.97
1979	3,373.66	27.00	124.95	14.79	1,847.62
1980	21,593.70	27.00	799.78	15.07	12,054.68
1981	15,030.08	27.00	556.68	15.36	8,552.14
1982	12,329.86	27.00	456.67	15.66	7,150.72
1983	14,205.57	27.00	526.14	15.96	8,396.95
1984	3,797.50	27.00	140.65	16.27	2,287.87
1986	501.80	27.00	18.59	16.90	314.03
1987	25.16	27.00	0.93	17.22	16.05
1990	1,186.46	27.00	43.94	18.23	801.04
1991	625.27	27.00	23.16	18.58	430.23
1993	260,306.27	27.00	9,641.11	19.30	186,028.51
1994	141,232.03	27.00	5,230.89	19.66	102,863.73
1995	86,380.16	27.00	3,199.31	20.04	64,117.58
1996	8,000.39	27.00	296.31	20.42	6,052.23
1997	1,194.00	27.00	44.22	20.82	920.63
1998	3,153.00	27.00	116.78	21.22	2,478.36
1999	444.07	27.00	16.45	21.64	355.93
2000	7,782.26	27.00	288.24	22.07	6,362.70
2003	16,027.24	27.00	593.61	23.50	13,947.91
2004	3,587.40	27.00	132.87	24.02	3,191.69
2006	3,817.54	27.00	141.39	25.18	3,560.69
Total	1,028,821.91	27.00	38,105.04	16.02	610,401.60

Composite Average Remaining Life ... 16.0 Years

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1928	0.47	0.00	0.00	0.00	0.00
1929	4.51	0.00	0.00	0.00	0.00
1930	16.60	0.00	0.00	0.00	0.00
1931	40.94	0.00	0.00	0.00	0.00
1932	53.64	0.00	0.00	0.00	0.00
1933	38.45	0.00	0.00	0.00	0.00
1934	48.97	0.00	0.00	0.00	0.00
1935	0.12	0.00	0.00	0.00	0.00
1936	22.69	0.00	0.00	0.00	0.00
1937	78.82	0.00	0.00	0.00	0.00
1938	677.09	0.00	0.00	0.00	0.00
1939	599.18	0.00	0.00	0.00	0.00
1940	774.02	0.00	0.00	0.00	0.00
1946	591.31	40.00	14.78	1.25	18.55
1947	4,357.15	40.00	108.93	1.50	163.63
1948	5,452.02	40.00	136.30	1.74	236.66
1949	6,772.12	40.00	169.30	1.99	337.38
1950	27,160.57	40.00	679.01	2.24	1,519.77
1951	26,972.27	40.00	674.31	2.50	1,684.84
1952	39,264.39	40.00	981.61	2.75	2,697.98
1953	37,957.36	40.00	948.93	3.01	2,855.55
1954	14,217.48	40.00	355.44	3.26	1,158.97
1955	49,393.21	40.00	1,234.83	3.52	4,348.96
1956	99,949.76	40.00	2,498.74	3.78	9,439.06
1957	75,819.13	40.00	1,895.48	4.04	7,666.20
1958	79,928.15	40.00	1,998.20	4.31	8,615.29
1959	100,640.26	40.00	2,516.00	4.59	11,555.61

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1960	89,050.64	40.00	2,226.26	4.88	10,866.00
1961	112,357.81	40.00	2,808.94	5.19	14,567.49
1962	169,239.40	40.00	4,230.98	5.50	23,288.51
1963	159,665.64	40.00	3,991.64	5.84	23,320.03
1964	177,339.62	40.00	4,433.49	6.20	27,479.72
1965	170,592.55	40.00	4,264.81	6.58	28,043.94
1966	144,823.91	40.00	3,620.60	6.98	25,253.71
1967	169,034.50	40.00	4,225.86	7.40	31,257.38
1968	163,711.36	40.00	4,092.78	7.84	32,098.74
1969	191,374.08	40.00	4,784.35	8.31	39,764.11
1970	865,791.54	40.00	21,644.77	8.81	190,590.46
1971	306,691.43	40.00	7,667.28	9.32	71,469.49
1972	327,925.45	40.00	8,198.13	9.86	80,857.30
1973	291,296.50	40.00	7,282.41	10.43	75,920.60
1974	63,353.13	40.00	1,583.83	11.01	17,441.27
1975	203,683.97	40.00	5,092.10	11.62	59,161.33
1976	117,032.32	40.00	2,925.81	12.25	35,833.58
1977	135,115.57	40.00	3,377.89	12.89	43,554.94
1978	117,572.98	40.00	2,939.32	13.56	39,862.99
1979	45,290.54	40.00	1,132.26	14.25	16,129.86
1980	162,676.15	40.00	4,066.90	14.95	60,794.72
1981	226,695.48	40.00	5,667.38	15.67	88,785.50
1982	235,468.24	40.00	5,886.70	16.40	96,548.06
1983	166,298.87	40.00	4,157.47	17.15	71,297.56
1984	120,946.52	40.00	3,023.66	17.91	54,165.16
1985	110,092.56	40.00	2,752.31	18.69	51,442.33
1986	160,136.81	40.00	4,003.42	19.48	77,997.06

Montana-Dakota Utilities Company
Gas Division
380.10 SERVICES - STEEL

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1987	219,656.54	40.00	5,491.41	20.29	111,400.26
1988	77,099.90	40.00	1,927.50	21.10	40,678.40
1989	71,993.16	40.00	1,799.83	21.93	39,476.16
1990	48,732.97	40.00	1,218.32	22.78	27,748.37
1991	42,639.17	40.00	1,065.98	23.63	25,187.89
1992	40,192.84	40.00	1,004.82	24.49	24,612.69
1993	92,030.54	40.00	2,300.76	25.37	58,370.76
1994	412,292.10	40.00	10,307.30	26.26	270,644.11
1995	35,156.93	40.00	878.92	27.15	23,866.24
1996	49,846.17	40.00	1,246.15	28.06	34,968.51
1997	47,892.35	40.00	1,197.31	28.98	34,693.94
1998	34,510.43	40.00	862.76	29.90	25,797.99
1999	37,193.65	40.00	929.84	30.83	28,670.81
2000	119,070.32	40.00	2,976.76	31.77	94,586.22
2001	22,706.88	40.00	567.67	32.72	18,575.42
2002	10,378.08	40.00	259.45	33.68	8,737.43
2003	26,232.42	40.00	655.81	34.64	22,714.80
2004	30,822.27	40.00	770.56	35.60	27,433.31
2005	7,071.96	40.00	176.80	36.57	6,465.91
2006	85,580.94	40.00	2,139.52	37.55	80,332.79
Total	7,285,187.87	32.97	182,070.69	13.43	2,445,052.31

Composite Average Remaining Life ... 13.4 *Years*

Montana-Dakota Utilities Company

Gas Division

380.20 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1969	639.26	40.00	15.98	8.31	132.83
1970	125.87	40.00	3.15	8.81	27.71
1971	7,513.09	40.00	187.83	9.32	1,750.80
1972	243,712.32	40.00	6,092.80	9.86	60,092.68
1973	219,978.45	40.00	5,499.46	10.43	57,332.98
1974	526,036.71	40.00	13,150.91	11.01	144,819.16
1975	303,921.23	40.00	7,598.03	11.62	88,275.89
1976	605,864.37	40.00	15,146.60	12.25	185,506.76
1977	415,865.67	40.00	10,396.63	12.89	134,055.65
1978	433,295.85	40.00	10,832.39	13.56	146,908.50
1979	681,544.71	40.00	17,038.61	14.25	242,726.69
1980	749,224.62	40.00	18,730.60	14.95	279,997.40
1981	629,692.61	40.00	15,742.30	15.67	246,619.70
1982	690,819.50	40.00	17,270.48	16.40	283,253.84
1983	914,242.95	40.00	22,856.06	17.15	391,964.72
1984	806,396.70	40.00	20,159.90	17.91	361,139.84
1985	894,262.37	40.00	22,356.54	18.69	417,856.95
1986	650,601.01	40.00	16,265.01	19.48	316,885.08
1987	581,559.46	40.00	14,538.98	20.29	294,941.71
1988	599,627.69	40.00	14,990.68	21.10	316,367.39
1989	480,530.33	40.00	12,013.25	21.93	263,490.23
1990	549,693.31	40.00	13,742.32	22.78	312,993.30
1991	761,453.49	40.00	19,036.32	23.63	449,807.30
1992	909,137.81	40.00	22,728.43	24.49	556,724.32
1993	1,029,232.49	40.00	25,730.79	25.37	652,795.07
1994	2,174,187.96	40.00	54,354.66	26.26	1,427,219.09
1995	1,010,168.27	40.00	25,254.19	27.15	685,751.54

Montana-Dakota Utilities Company
Gas Division
380.20 SERVICES - PLASTIC

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1996	1,353,943.67	40.00	33,848.57	28.06	949,830.22
1997	1,394,110.19	40.00	34,852.73	28.98	1,009,914.53
1998	1,279,471.07	40.00	31,986.76	29.90	956,458.15
1999	996,161.31	40.00	24,904.02	30.83	767,893.18
2000	1,133,469.07	40.00	28,336.71	31.77	900,396.93
2001	1,201,231.23	40.00	30,030.76	32.72	982,670.30
2002	1,327,820.31	40.00	33,195.49	33.68	1,117,907.43
2003	2,443,249.82	40.00	61,081.20	34.64	2,115,623.51
2004	2,608,376.50	40.00	65,209.37	35.60	2,321,581.35
2005	2,823,012.41	40.00	70,575.26	36.57	2,581,086.12
2006	2,919,892.55	40.00	72,997.26	37.55	2,740,833.49
2007	3,067,885.95	40.00	76,697.10	38.53	2,954,799.51
2008	3,272,321.05	40.00	81,807.97	39.51	3,232,057.45
Total	42,690,273.23	40.00	1,067,256.11	29.00	30,950,489.31

Composite Average Remaining Life ... 29.0 Years

Montana-Dakota Utilities Company
Gas Division
380.30 SERVICES - FARM & FUEL LINES

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1977	277.44	30.00	9.25	8.96	82.89
1980	6,116.04	30.00	203.86	10.37	2,114.36
1981	9,184.73	30.00	306.15	10.88	3,329.51
1982	34,231.80	30.00	1,141.03	11.40	13,005.04
1983	7,818.86	30.00	260.62	11.94	3,110.82
1984	18,901.15	30.00	630.02	12.49	7,869.75
1985	13,311.43	30.00	443.70	13.06	5,796.45
1986	1,610.76	30.00	53.69	13.65	732.96
1987	1,964.42	30.00	65.48	14.25	933.38
1988	9,854.82	30.00	328.49	14.87	4,885.84
1989	1,711.71	30.00	57.06	15.51	884.74
1991	3,912.84	30.00	130.42	16.81	2,193.04
1992	4,904.22	30.00	163.47	17.49	2,858.74
1993	1,286.17	30.00	42.87	18.17	779.11
1994	63,263.97	30.00	2,108.75	18.87	39,794.25
1997	18,107.93	30.00	603.58	21.03	12,691.35
1998	3,815.98	30.00	127.20	21.76	2,768.34
1999	2,163.03	30.00	72.10	22.51	1,623.00
2000	3,381.11	30.00	112.70	23.27	2,622.08
2001	3,381.69	30.00	112.72	24.03	2,708.51
2003	1,614.04	30.00	53.80	25.58	1,376.12
2004	1,959.95	30.00	65.33	26.36	1,722.42
2006	5,554.58	30.00	185.15	27.96	5,177.05
2007	4,128.53	30.00	137.61	28.77	3,959.36
2008	26,182.98	30.00	872.74	29.59	25,823.50

Montana-Dakota Utilities Company

Gas Division

380.30 SERVICES - FARM & FUEL LINES

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 30 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	248,640.18	30.00	8,287.81	17.96	148,842.60

Composite Average Remaining Life ... 17.9 *Years*

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1956	4.09	35.00	0.12	0.50	0.06
1957	45.10	35.00	1.29	0.56	0.72
1958	179.31	35.00	5.12	0.71	3.61
1959	962.55	35.00	27.50	0.89	24.45
1960	3,488.50	35.00	99.67	1.11	110.21
1961	7,018.73	35.00	200.53	1.31	263.06
1962	19,225.60	35.00	549.30	1.54	846.87
1963	23,272.67	35.00	664.93	1.79	1,187.38
1964	30,460.15	35.00	870.29	2.04	1,774.60
1965	48,386.33	35.00	1,382.46	2.30	3,179.14
1966	61,082.38	35.00	1,745.20	2.57	4,479.76
1967	76,538.71	35.00	2,186.81	2.85	6,225.24
1968	106,050.55	35.00	3,030.00	3.13	9,482.99
1969	103,252.28	35.00	2,950.05	3.43	10,117.71
1970	287,816.06	35.00	8,223.27	3.75	30,849.14
1971	207,409.99	35.00	5,925.97	4.10	24,299.72
1972	424,892.55	35.00	12,139.72	4.48	54,419.74
1973	421,937.56	35.00	12,055.29	4.90	59,115.42
1974	902,080.96	35.00	25,773.60	5.37	138,298.37
1975	845,873.98	35.00	24,167.69	5.88	142,036.42
1976	846,194.48	35.00	24,176.85	6.44	155,581.84
1977	815,695.45	35.00	23,305.45	7.04	163,986.41
1978	749,874.08	35.00	21,424.85	7.67	164,410.87
1979	1,227,085.87	35.00	35,059.40	8.34	292,355.75
1980	1,198,260.48	35.00	34,235.82	9.02	308,973.98
1981	1,577,742.46	35.00	45,078.10	9.73	438,547.56
1982	548,679.84	35.00	15,676.48	10.46	163,899.92

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1983	848,124.07	35.00	24,231.98	11.20	271,467.25
1984	1,090,435.13	35.00	31,155.11	11.97	372,991.21
1985	826,611.63	35.00	23,617.34	12.76	301,422.96
1986	425,761.29	35.00	12,164.54	13.57	165,129.15
1987	288,585.15	35.00	8,245.24	14.41	118,789.11
1988	85,552.91	35.00	2,444.36	15.26	37,295.14
1989	115,481.85	35.00	3,299.46	16.13	53,216.27
1990	405,126.97	35.00	11,574.99	17.02	196,972.34
1991	697,757.76	35.00	19,935.82	17.92	357,273.65
1992	762,983.82	35.00	21,799.41	18.84	410,694.86
1993	1,139,059.30	35.00	32,544.37	19.77	643,441.46
1994	1,231,332.26	35.00	35,180.72	20.71	728,740.51
1995	1,083,266.23	35.00	30,950.29	21.67	670,591.33
1996	1,098,322.81	35.00	31,380.47	22.63	710,102.89
1997	1,195,724.93	35.00	34,163.38	23.60	806,197.50
1998	1,401,185.88	35.00	40,033.66	24.57	983,788.12
1999	1,604,913.84	35.00	45,854.42	25.55	1,171,807.42
2000	1,559,545.77	35.00	44,558.20	26.54	1,182,581.34
2001	2,011,299.14	35.00	57,465.37	27.53	1,581,953.49
2002	1,653,583.71	35.00	47,244.98	28.52	1,347,432.81
2003	1,433,810.90	35.00	40,965.79	29.51	1,209,057.27
2004	1,009,165.10	35.00	28,833.13	30.51	879,675.33
2005	2,812,347.38	35.00	80,352.33	31.51	2,531,567.34
2006	2,188,549.32	35.00	62,529.63	32.50	2,032,428.74
2007	8,063,249.48	35.00	230,377.26	33.50	7,718,048.59
2008	9,606,762.91	35.00	274,477.39	34.50	9,469,642.95

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R4

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
Total	55,172,050.25	35.00	1,576,335.40	24.19	38,126,779.95

Composite Average Remaining Life ... 24.1 Years

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1946	968.71	40.00	24.22	3.23	78.11
1947	1,596.34	40.00	39.91	3.52	140.36
1948	1,939.60	40.00	48.49	3.80	184.40
1949	2,322.64	40.00	58.07	4.10	237.82
1950	6,177.73	40.00	154.44	4.38	677.08
1951	4,184.77	40.00	104.62	4.68	489.52
1952	5,799.08	40.00	144.98	4.97	720.79
1953	8,613.73	40.00	215.34	5.27	1,135.30
1954	165.41	40.00	4.14	5.57	23.05
1955	12,537.67	40.00	313.44	5.88	1,843.86
1956	26,331.90	40.00	658.29	6.20	4,078.88
1957	12,724.80	40.00	318.12	6.52	2,074.15
1958	11,135.45	40.00	278.38	6.85	1,907.14
1959	19,098.97	40.00	477.47	7.19	3,434.52
1960	33,403.74	40.00	835.09	7.54	6,300.70
1961	22,425.96	40.00	560.65	7.91	4,434.42
1962	25,275.42	40.00	631.88	8.29	5,235.58
1963	18,599.42	40.00	464.98	8.68	4,033.86
1964	19,028.09	40.00	475.70	9.08	4,318.54
1965	21,237.31	40.00	530.93	9.50	5,041.23
1966	12,397.28	40.00	309.93	9.93	3,076.54
1967	20,567.31	40.00	514.18	10.37	5,333.08
1968	26,395.48	40.00	659.88	10.83	7,148.49
1969	19,585.32	40.00	489.63	11.31	5,536.68
1970	51,342.38	40.00	1,283.55	11.80	15,144.34
1971	55,885.95	40.00	1,397.14	12.30	17,189.65
1972	88,716.27	40.00	2,217.89	12.82	28,442.84

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1973	79,350.28	40.00	1,983.75	13.36	26,499.93
1974	119,043.64	40.00	2,976.07	13.91	41,393.81
1975	123,469.89	40.00	3,086.73	14.47	44,671.93
1976	107,001.98	40.00	2,675.03	15.05	40,263.03
1977	101,770.14	40.00	2,544.24	15.64	39,799.87
1978	86,775.98	40.00	2,169.39	16.25	35,252.98
1979	113,374.14	40.00	2,834.34	16.87	47,813.35
1980	192,944.77	40.00	4,823.59	17.50	84,428.53
1981	170,728.06	40.00	4,268.18	18.15	77,461.81
1982	91,313.14	40.00	2,282.82	18.81	42,935.98
1983	122,805.13	40.00	3,070.11	19.48	59,802.59
1984	168,140.74	40.00	4,203.50	20.16	84,755.88
1985	140,079.35	40.00	3,501.96	20.86	73,043.48
1986	84,042.17	40.00	2,101.04	21.57	45,310.05
1987	63,611.63	40.00	1,590.28	22.28	35,436.41
1988	69,694.36	40.00	1,742.35	23.01	40,096.80
1989	65,598.83	40.00	1,639.96	23.75	38,953.20
1990	84,349.17	40.00	2,108.72	24.50	51,671.47
1991	119,271.84	40.00	2,981.78	25.26	75,331.67
1992	137,882.13	40.00	3,447.03	26.04	89,745.22
1993	195,622.03	40.00	4,890.52	26.82	131,142.31
1994	186,273.42	40.00	4,656.81	27.61	128,557.74
1995	134,052.00	40.00	3,351.28	28.41	95,194.53
1996	134,481.43	40.00	3,362.02	29.21	98,220.01
1997	172,828.87	40.00	4,320.70	30.03	129,757.62
1998	193,392.21	40.00	4,834.78	30.86	149,193.18
1999	152,290.64	40.00	3,807.24	31.69	120,661.05

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2000	178,355.16	40.00	4,458.85	32.54	145,072.39
2001	150,252.44	40.00	3,756.29	33.39	125,408.25
2002	110,921.78	40.00	2,773.03	34.25	94,963.09
2003	208,126.53	40.00	5,203.13	35.11	182,687.38
2004	61,538.23	40.00	1,538.45	35.98	55,360.93
2005	214,595.36	40.00	5,364.85	36.87	197,776.27
2006	211,246.36	40.00	5,281.13	37.75	199,378.65
2007	137,795.62	40.00	3,444.87	38.65	133,133.35
2008	343,731.82	40.00	8,593.25	39.55	339,843.43
Total	5,555,208.00	40.00	138,879.43	25.41	3,529,279.13

Composite Average Remaining Life ... 25.4 *Years*

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1951	1,386.71	35.00	39.62	2.03	80.32
1952	1,429.10	35.00	40.83	2.31	94.30
1953	635.17	35.00	18.15	2.60	47.18
1954	218.79	35.00	6.25	2.88	18.03
1955	693.62	35.00	19.82	3.17	62.83
1956	1,936.48	35.00	55.33	3.46	191.35
1957	1,735.17	35.00	49.58	3.75	185.83
1958	5,501.93	35.00	157.20	4.04	635.12
1959	1,852.56	35.00	52.93	4.33	229.44
1960	4,322.26	35.00	123.49	4.64	572.49
1961	3,368.40	35.00	96.24	4.94	475.21
1962	724.69	35.00	20.71	5.25	108.64
1963	4,626.52	35.00	132.19	5.56	735.53
1964	7,416.55	35.00	211.90	5.89	1,248.49
1965	5,118.73	35.00	146.25	6.23	911.19
1966	2,265.77	35.00	64.74	6.58	426.04
1967	1,755.93	35.00	50.17	6.95	348.47
1968	4,086.61	35.00	116.76	7.32	855.12
1969	5,566.57	35.00	159.04	7.72	1,227.31
1970	4,655.92	35.00	133.03	8.13	1,080.92
1971	2,043.76	35.00	58.39	8.55	499.30
1972	1,711.63	35.00	48.90	8.99	439.75
1973	2,605.42	35.00	74.44	9.45	703.51
1974	1,251.06	35.00	35.74	9.93	354.77
1975	3,402.21	35.00	97.21	10.42	1,012.67
1980	9,776.15	35.00	279.32	13.13	3,668.55
1981	255.91	35.00	7.31	13.73	100.36

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1982	1,969.66	35.00	56.28	14.33	806.65
1983	1,660.42	35.00	47.44	14.96	709.60
1984	33,587.50	35.00	959.64	15.60	14,967.28
1985	84,373.90	35.00	2,410.67	16.25	39,174.37
1986	5,405.45	35.00	154.44	16.92	2,612.87
1987	60,168.84	35.00	1,719.10	17.60	30,256.27
1988	89,085.28	35.00	2,545.28	18.29	46,564.26
1989	151.33	35.00	4.32	19.00	82.16
1990	23,839.88	35.00	681.13	19.72	13,435.36
1991	19,661.68	35.00	561.76	20.46	11,493.07
1992	16,865.91	35.00	481.88	21.21	10,218.41
1993	28,166.89	35.00	804.76	21.96	17,675.27
1994	13,506.82	35.00	385.91	22.73	8,772.74
1995	2,339.79	35.00	66.85	23.51	1,571.83
1996	24,548.02	35.00	701.37	24.30	17,046.35
1997	46,554.95	35.00	1,330.13	25.11	33,395.41
1998	8,477.45	35.00	242.21	25.92	6,277.98
1999	15,936.47	35.00	455.32	26.74	12,176.32
2000	10,302.92	35.00	294.37	27.57	8,116.98
2001	1,537.15	35.00	43.92	28.42	1,247.98
2002	1,147.21	35.00	32.78	29.27	959.26
2003	55,438.44	35.00	1,583.95	30.13	47,718.12
2004	22,740.05	35.00	649.71	30.99	20,137.53
2005	12,860.95	35.00	367.45	31.87	11,711.20
2006	21,193.96	35.00	605.54	32.76	19,834.93
2007	14,006.76	35.00	400.19	33.65	13,465.69
2008	179,505.58	35.00	5,128.70	34.55	177,185.54

Montana-Dakota Utilities Company

Gas Division

385.00 IND. MEAS. & REG. STA. EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve:* R2

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
Total	875,376.88	35.00	25,010.60	23.35	583,926.15

Composite Average Remaining Life ... 23.3 Years

Montana-Dakota Utilities Company

Gas Division

386.10 MISC. PROPERTY ON CUSTOMERS PREMISE

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1997	1,679.84	15.00	111.99	5.05	565.28
Total	1,679.84	15.00	111.99	5.05	565.28

Composite Average Remaining Life ... 5.05 *Years*

Montana-Dakota Utilities Company
Gas Division
386.20 CNG REFUELING STATIONS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 15 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	57,128.05	15.00	3,808.51	2.41	9,188.89
1993	14,007.69	15.00	933.84	2.82	2,629.25
1994	92,365.69	15.00	6,157.67	3.28	20,203.45
1995	81,308.77	15.00	5,420.55	3.81	20,658.99
1996	17,070.15	15.00	1,138.00	4.40	5,009.68
Total	261,880.35	15.00	17,458.58	3.30	57,690.26

Composite Average Remaining Life ... 3.30 *Years*

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1969	24.73	20.00	1.24	0.50	0.62
1970	53.81	20.00	2.69	0.67	1.79
1971	203.60	20.00	10.18	0.96	9.73
1972	523.57	20.00	26.18	1.27	33.19
1973	831.19	20.00	41.56	1.52	62.99
1974	1,407.59	20.00	70.38	1.74	122.67
1975	987.96	20.00	49.40	1.96	96.88
1976	3,265.59	20.00	163.27	2.20	359.45
1977	6,522.90	20.00	326.13	2.45	799.51
1978	9,513.39	20.00	475.65	2.72	1,294.27
1979	5,924.98	20.00	296.24	3.00	888.17
1980	14,167.11	20.00	708.32	3.29	2,330.34
1981	15,747.00	20.00	787.32	3.59	2,826.38
1982	23,699.66	20.00	1,184.93	3.91	4,627.67
1983	40,748.69	20.00	2,037.35	4.23	8,627.43
1984	56,853.74	20.00	2,842.56	4.58	13,028.99
1985	78,501.64	20.00	3,924.91	4.95	19,438.09
1986	121,758.42	20.00	6,087.65	5.34	32,537.38
1987	56,842.72	20.00	2,842.01	5.76	16,375.16
1988	116,237.31	20.00	5,811.61	6.20	36,057.68
1989	33,018.38	20.00	1,650.85	6.67	11,016.48
1990	21,234.06	20.00	1,061.66	7.17	7,609.82
1991	109,435.54	20.00	5,471.54	7.69	42,074.43
1992	50,171.35	20.00	2,508.46	8.24	20,659.44
1993	61,963.71	20.00	3,098.05	8.81	27,288.20
1994	101,342.03	20.00	5,066.88	9.40	47,644.26
1995	24,075.11	20.00	1,203.70	10.02	12,063.58

Montana-Dakota Utilities Company

Gas Division

387.10 CATHODIC PROTECTION EQUIP.

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1996	69,255.63	20.00	3,462.63	10.66	36,916.60
1997	78,998.93	20.00	3,949.77	11.32	44,721.01
1998	69,398.42	20.00	3,469.77	12.00	41,641.82
1999	60,638.16	20.00	3,031.78	12.70	38,500.65
2000	75,830.12	20.00	3,791.34	13.41	50,849.64
2001	80,332.19	20.00	4,016.43	14.14	56,796.31
2002	32,490.24	20.00	1,624.44	14.88	24,176.02
2003	44,533.85	20.00	2,226.59	15.64	34,818.29
2004	93,283.55	20.00	4,663.97	16.40	76,509.16
2005	49,742.83	20.00	2,487.03	17.18	42,735.64
2006	96,248.21	20.00	4,812.20	17.97	86,492.09
2007	3,673.73	20.00	183.68	18.78	3,448.75
2008	28,336.09	20.00	1,416.74	19.59	27,753.16
Total	1,737,817.73	20.00	86,887.08	10.05	873,233.77

Composite Average Remaining Life ... 10.0 Years

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 25 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1950	5,168.26	0.00	0.00	0.00	0.00
1951	17,318.56	0.00	0.00	0.00	0.00
1952	7,404.96	0.00	0.00	0.00	0.00
1953	458.08	0.00	0.00	0.00	0.00
1955	9,665.92	0.00	0.00	0.00	0.00
1956	1,589.52	0.00	0.00	0.00	0.00
1958	6,603.77	0.00	0.00	0.00	0.00
1959	7,167.79	0.00	0.00	0.00	0.00
1960	13,369.58	0.00	0.00	0.00	0.00
1961	1,649.66	0.00	0.00	0.00	0.00
1962	3,139.70	0.00	0.00	0.00	0.00
1963	12,662.09	0.00	0.00	0.00	0.00
1964	2,715.58	0.00	0.00	0.00	0.00
1965	2,974.71	0.00	0.00	0.00	0.00
1966	671.02	0.00	0.00	0.00	0.00
1967	2,593.84	25.00	103.75	0.50	51.88
1968	897.83	25.00	35.91	0.57	20.36
1969	388.92	25.00	15.56	0.75	11.63
1970	3,128.26	25.00	125.13	0.96	120.61
1971	155.84	25.00	6.23	1.20	7.47
1974	244.19	25.00	9.77	1.95	19.02
1978	365.07	25.00	14.60	3.01	43.93
1987	12,250.87	25.00	490.03	6.92	3,392.36
1988	21,955.90	25.00	878.23	7.54	6,620.02
1989	17,429.78	25.00	697.19	8.19	5,706.66
1990	26,082.25	25.00	1,043.29	8.86	9,246.14
1991	5,752.00	25.00	230.08	9.57	2,201.28

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 25 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	15,770.85	25.00	630.83	10.30	6,496.41
1993	15,868.41	25.00	634.74	11.05	7,015.67
1994	62,351.00	25.00	2,494.03	11.83	29,505.31
1995	10,987.88	25.00	439.51	12.63	5,550.79
1996	54,771.05	25.00	2,190.84	13.45	29,464.57
1997	34,316.61	25.00	1,372.66	14.29	19,613.06
1998	9,317.74	25.00	372.71	15.15	5,645.24
2000	155,639.50	25.00	6,225.57	16.92	105,307.97
2003	1,305.49	25.00	52.22	19.68	1,027.81
2004	11,203.57	25.00	448.14	20.63	9,245.19
2005	30,270.40	25.00	1,210.81	21.59	26,138.66
2006	2,419.05	25.00	96.76	22.55	2,182.38
Total	588,025.50	15.38	19,818.61	13.86	274,634.42

Composite Average Remaining Life ... 13.8 Years

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 31 *Survivor Curve: R4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1928	3,694.59	0.00	0.00	0.00	0.00
1929	3,786.96	0.00	0.00	0.00	0.00
1930	3,881.63	0.00	0.00	0.00	0.00
1931	3,978.67	0.00	0.00	0.00	0.00
1932	4,078.14	0.00	0.00	0.00	0.00
1933	4,180.09	0.00	0.00	0.00	0.00
1934	4,284.59	0.00	0.00	0.00	0.00
1935	4,391.70	0.00	0.00	0.00	0.00
1936	4,501.50	0.00	0.00	0.00	0.00
1937	4,614.04	0.00	0.00	0.00	0.00
1938	4,729.39	0.00	0.00	0.00	0.00
1939	4,847.62	0.00	0.00	0.00	0.00
1940	4,968.81	0.00	0.00	0.00	0.00
1946	4,968.81	0.00	0.00	0.00	0.00
1947	4,968.81	0.00	0.00	0.00	0.00
1948	4,968.81	0.00	0.00	0.00	0.00
1949	30,982.36	0.00	0.00	0.00	0.00
1950	13,204.59	0.00	0.00	0.00	0.00
1951	124,344.40	0.00	0.00	0.00	0.00
1952	7,388.16	0.00	0.00	0.00	0.00
1953	15,932.86	0.00	0.00	0.00	0.00
1954	2,768.27	0.00	0.00	0.00	0.00
1955	53,795.97	0.00	0.00	0.00	0.00
1956	93,195.50	0.00	0.00	0.00	0.00
1957	3,612.33	0.00	0.00	0.00	0.00
1958	1,566.79	0.00	0.00	0.00	0.00
1959	1,749.22	0.00	0.00	0.00	0.00

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 31 *Survivor Curve: R4*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1960	16,524.43	0.00	0.00	0.00	0.00
1961	7,218.76	0.00	0.00	0.00	0.00
1962	4,440.15	31.00	143.23	0.50	71.62
1963	6,684.89	31.00	215.64	0.55	117.95
1964	14,651.23	31.00	472.62	0.69	324.91
1965	42,624.79	31.00	1,375.00	0.85	1,174.19
1966	47,636.27	31.00	1,536.66	1.07	1,651.19
1967	8,545.76	31.00	275.67	1.31	359.78
1968	2,982.16	31.00	96.20	1.55	148.82
1969	3,703.29	31.00	119.46	1.79	213.86
1970	116,010.29	31.00	3,742.28	2.05	7,676.55
1971	6,987.75	31.00	225.41	2.32	522.83
1972	96,029.36	31.00	3,097.73	2.60	8,043.93
1973	29,301.34	31.00	945.21	2.89	2,729.17
1974	5,994.47	31.00	193.37	3.19	617.67
1975	5,979.08	31.00	192.87	3.53	681.31
1976	16,931.66	31.00	546.18	3.90	2,132.84
1977	4,176.87	31.00	134.74	4.32	581.98
1978	52,439.58	31.00	1,691.60	4.78	8,093.37
1979	1,833.19	31.00	59.14	5.30	313.44
1980	25,223.67	31.00	813.67	5.87	4,775.00
1981	9,753.34	31.00	314.62	6.48	2,039.79
1982	8,967.81	31.00	289.28	7.14	2,064.65
1983	28,118.00	31.00	907.03	7.82	7,089.12
1984	28,651.13	31.00	924.23	8.52	7,871.03
1985	14,557.41	31.00	469.59	9.24	4,338.90
1986	31,006.41	31.00	1,000.21	9.99	9,989.04

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 31 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1987	4,480.33	31.00	144.53	10.76	1,555.22
1988	8,981.21	31.00	289.72	11.56	3,348.31
1989	10,215.66	31.00	329.54	12.38	4,078.77
1990	2,983.04	31.00	96.23	13.22	1,272.13
1991	12,219.54	31.00	394.18	14.09	5,552.28
1992	1,293.73	31.00	41.73	14.97	624.76
1993	40,602.70	31.00	1,309.77	15.87	20,789.76
1994	22,290.25	31.00	719.04	16.79	12,074.07
1996	12,566.18	31.00	405.36	18.67	7,569.09
1997	73,670.57	31.00	2,376.47	19.63	46,649.16
1998	38,971.09	31.00	1,257.13	20.60	25,891.68
1999	44,495.93	31.00	1,435.36	21.57	30,960.05
2000	48,371.18	31.00	1,560.36	22.55	35,186.10
2001	17,143.29	31.00	553.01	23.53	13,015.08
2002	4,235,573.43	31.00	136,631.69	24.52	3,350,737.45
2003	22,039.97	31.00	710.97	25.52	18,140.94
2004	17,309.87	31.00	558.38	26.51	14,802.80
2005	54,381.59	31.00	1,754.25	27.51	48,252.66
2006	33,862.46	31.00	1,092.34	28.50	31,135.42
2007	33,755.29	31.00	1,088.88	29.50	32,123.75
2008	43,730.30	31.00	1,410.66	30.50	43,025.57
Total	5,835,295.31	19.01	173,941.25	21.96	3,820,407.96

Composite Average Remaining Life ... 21.9 *Years*

Montana-Dakota Utilities Company
Gas Division
392.10 TRANSPORTATION EQUIPMENT - TRAILERS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 8 *Survivor Curve:* R0.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	3,830.17	0.00	0.00	0.00	0.00
1993	8,158.20	8.01	1,019.09	0.50	509.54
1994	6,417.08	8.01	801.59	0.80	639.49
1995	4,489.00	8.01	560.75	1.19	666.67
1996	153.66	8.01	19.19	1.57	30.21
1997	12,759.71	8.01	1,593.89	1.96	3,126.97
1998	5,899.85	8.01	736.98	2.36	1,741.82
2000	88,044.58	8.01	10,998.16	3.23	35,571.73
2001	12,265.67	8.01	1,532.18	3.71	5,686.11
2002	7,212.24	8.01	900.92	4.22	3,799.66
2003	14,077.17	8.01	1,758.46	4.75	8,356.55
2005	27,546.32	8.01	3,440.97	5.89	20,272.21
2006	159.26	8.01	19.89	6.48	128.99
2007	63,852.30	8.01	7,976.16	7.09	56,513.82
2008	142,194.48	8.01	17,762.33	7.70	136,699.30
Total	397,059.69	7.47	49,120.57	5.57	273,743.07

Composite Average Remaining Life ... 5.57 *Years*

Montana-Dakota Utilities Company
Gas Division
392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 7 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1997	208.11	7.00	29.73	0.50	14.86
1998	19,547.61	7.00	2,792.38	0.51	1,429.31
1999	85,568.14	7.00	12,223.43	0.68	8,364.10
2000	447,299.73	7.00	63,896.87	0.92	58,636.06
2001	702,952.20	7.00	100,416.88	1.24	124,101.32
2002	762,449.31	7.00	108,916.06	1.69	183,751.61
2003	1,006,442.98	7.00	143,770.61	2.28	327,334.58
2004	1,565,621.54	7.00	223,649.39	2.98	666,416.24
2005	1,131,688.54	7.00	161,661.96	3.77	609,341.90
2006	1,087,712.10	7.00	155,379.92	4.63	719,464.32
2007	1,120,325.21	7.00	160,038.71	5.55	888,167.64
2008	845,278.74	7.00	120,748.26	6.51	786,082.52
Total	8,775,094.21	7.00	1,253,524.19	3.49	4,373,104.46

Composite Average Remaining Life ... 3.49 *Years*

Montana-Dakota Utilities Company
Gas Division
396.10 WORK EQUIPMENT TRAILERS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **10** *Survivor Curve:* **R2**

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	12,792.01	10.00	1,279.08	0.66	844.96
1993	24,440.69	10.00	2,443.85	0.91	2,222.29
1994	30,556.65	10.00	3,055.39	1.18	3,611.45
1995	23,799.02	10.00	2,379.69	1.47	3,497.63
1996	51,926.33	10.00	5,192.16	1.78	9,266.40
1997	8,761.03	10.00	876.02	2.14	1,876.78
1998	15,399.71	10.00	1,539.83	2.55	3,932.84
1999	57,867.49	10.00	5,786.22	3.03	17,504.78
2000	4,055.38	10.00	405.50	3.56	1,442.32
2001	17,109.20	10.00	1,710.76	4.15	7,094.14
2002	49,805.87	10.00	4,980.13	4.79	23,859.60
2004	44,652.90	10.00	4,464.88	6.22	27,788.10
2005	47,478.42	10.00	4,747.41	7.00	33,248.34
2006	74,339.18	10.00	7,433.24	7.82	58,130.04
2007	32,993.92	10.00	3,299.09	8.67	28,604.92
2008	34,598.05	10.00	3,459.49	9.55	33,040.47
Total	530,575.85	10.00	53,052.76	4.82	255,965.07

Composite Average Remaining Life ... *4.82* *Years*

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 4 *Survivor Curve:* L1

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1996	0.07	4.00	0.02	0.50	0.01
1997	104.77	4.00	26.17	0.50	13.12
1998	792.42	4.00	197.96	0.56	111.35
1999	9,084.88	4.00	2,269.53	0.69	1,557.18
2000	9,562.03	4.00	2,388.73	0.85	2,021.46
2001	75,021.49	4.00	18,741.43	1.03	19,344.11
2002	34,348.06	4.00	8,580.63	1.24	10,676.56
2003	339,180.78	4.00	84,732.17	1.48	125,689.17
2004	528,180.47	4.00	131,946.98	1.75	231,505.09
2005	776,136.08	4.00	193,889.80	2.06	400,017.86
2006	1,140,275.87	4.00	284,857.09	2.42	688,554.48
2007	1,717,899.05	4.00	429,155.56	2.86	1,227,158.17
2008	1,511,648.10	4.00	377,631.14	3.55	1,342,000.37
Total	6,142,234.07	4.00	1,534,417.22	2.64	4,048,648.93

Composite Average Remaining Life ... 2.64 *Years*

Montana-Dakota Utilities Company
Gas Division
374.20 LAND RIGHTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1985 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1985	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	65.41	14.73	22.52%	0.00	0.00%	14.73	22.52%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
374.20 LAND RIGHTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1985 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1985 - 1987	1,754.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	65.41	14.73	22.52%	0.00	0.00%	14.73	22.52%
2002 - 2004	65.41	14.73	22.52%	0.00	0.00%	14.73	22.52%
2003 - 2005	65.41	14.73	22.52%	0.00	0.00%	14.73	22.52%
2004 - 2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005 - 2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
374.20 LAND RIGHTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1985 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1985 - 2008	1,819.54	14.73	0.81	0.00	0.00	14.73	0.81

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	65.0
Average Retirement Age (Yrs)	8.2
Years To ASL	56.8
Inflation Factor At 2.75% to ASL	4.66

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	9.24%
1994-2008	**15 - Year Trend**	10.29%
1999-2008	**10 - Year Trend**	9.01%
2004-2008	**5 - Year Trend**	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	0.00%
Net Salvage	0.00%

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	3,425.08	435.45	12.71%	230.31	6.72%	205.14	5.99%
1969	4,310.44	819.74	19.02%	656.20	15.22%	163.54	3.79%
1970	4,433.29	1,076.90	24.29%	450.82	10.17%	626.08	14.12%
1971	2,081.69	883.96	42.46%	48.83	2.35%	835.13	40.12%
1972	2,058.30	0.00	0.00%	19.89	0.97%	(19.89)	-0.97%
1973	1,012.35	0.00	0.00%	59.26	5.85%	(59.26)	-5.85%
1974	3,269.04	2,424.62	74.17%	246.45	7.54%	2,178.17	66.63%
1975	1,584.93	98.73	6.23%	470.32	29.67%	(371.59)	-23.45%
1976	2,446.53	0.00	0.00%	166.82	6.82%	(166.82)	-6.82%
1977	661.00	0.00	0.00%	144.69	21.89%	(144.69)	-21.89%
1978	1,605.72	0.00	0.00%	875.01	54.49%	(875.01)	-54.49%
1979	303.10	0.00	0.00%	19.22	6.34%	(19.22)	-6.34%
1980	1,134.17	0.00	0.00%	627.51	55.33%	(627.51)	-55.33%
1981	1,442.23	0.00	0.00%	230.47	15.98%	(230.47)	-15.98%
1982	2,256.89	0.00	0.00%	609.90	27.02%	(609.90)	-27.02%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	628.89	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	14,934.74	1,870.26	12.52%	733.70	4.91%	1,136.56	7.61%
1986	1,006.41	-620.46	-61.65%	781.10	77.61%	(1,401.56)	-139.26%
1987	891.58	0.00	0.00%	83.33	9.35%	(83.33)	-9.35%
1988	457.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	1,618.28	1.00	0.06%	448.28	27.70%	(447.28)	-27.64%
1990	773.00	0.00	0.00%	523.47	67.72%	(523.47)	-67.72%
1991	3,506.79	0.00	0.00%	2,521.31	71.90%	(2,521.31)	-71.90%
1992	3,956.71	0.00	0.00%	2,552.03	64.50%	(2,552.03)	-64.50%
1993	3,366.82	0.00	0.00%	1,633.72	48.52%	(1,633.72)	-48.52%
1994	5,438.75	0.00	0.00%	2,211.80	40.67%	(2,211.80)	-40.67%
1995	247.53	4,904.42	1981.34%	734.55	296.75%	4,169.87	1684.59%

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	3,122.98	0.00	0.00%	4,739.85	151.77%	(4,739.85)	-151.77%
1997	5,835.64	850.00	14.57%	257.00	4.40%	593.00	10.16%
1998	150.63	0.00	0.00%	600.00	398.33%	(600.00)	-398.33%
1999	454.69	0.00	0.00%	4,286.94	942.83%	(4,286.94)	-942.83%
2000	3,897.84	1.00	0.03%	2,219.11	56.93%	(2,218.11)	-56.91%
2001	786.50	0.00	0.00%	2,596.09	330.08%	(2,596.09)	-330.08%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	450.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	8,146.99	0.00	0.00%	4,128.60	50.68%	(4,128.60)	-50.68%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	3,720.13	0.00	0.00%	2,253.63	60.58%	(2,253.63)	-60.58%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	1,952.69	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	12,168.81	2,332.09	19.16%	1,337.33	10.99%	994.76	8.17%
1969 - 1971	10,825.42	2,780.60	25.69%	1,155.85	10.68%	1,624.75	15.01%
1970 - 1972	8,573.28	1,960.86	22.87%	519.54	6.06%	1,441.32	16.81%
1971 - 1973	5,152.34	883.96	17.16%	127.98	2.48%	755.98	14.67%
1972 - 1974	6,339.69	2,424.62	38.25%	325.60	5.14%	2,099.02	33.11%
1973 - 1975	5,866.32	2,523.35	43.01%	776.03	13.23%	1,747.32	29.79%
1974 - 1976	7,300.50	2,523.35	34.56%	883.59	12.10%	1,639.76	22.46%
1975 - 1977	4,692.46	98.73	2.10%	781.83	16.66%	(683.10)	-14.56%
1976 - 1978	4,713.25	0.00	0.00%	1,186.52	25.17%	(1,186.52)	-25.17%
1977 - 1979	2,569.82	0.00	0.00%	1,038.92	40.43%	(1,038.92)	-40.43%
1978 - 1980	3,042.99	0.00	0.00%	1,521.74	50.01%	(1,521.74)	-50.01%
1979 - 1981	2,879.50	0.00	0.00%	877.20	30.46%	(877.20)	-30.46%
1980 - 1982	4,833.29	0.00	0.00%	1,467.88	30.37%	(1,467.88)	-30.37%
1981 - 1983	3,699.12	0.00	0.00%	840.37	22.72%	(840.37)	-22.72%
1982 - 1984	2,885.78	0.00	0.00%	609.90	21.13%	(609.90)	-21.13%
1983 - 1985	15,563.63	1,870.26	12.02%	733.70	4.71%	1,136.56	7.30%
1984 - 1986	16,570.04	1,249.80	7.54%	1,514.80	9.14%	(265.00)	-1.60%
1985 - 1987	16,832.73	1,249.80	7.42%	1,598.13	9.49%	(348.33)	-2.07%
1986 - 1988	2,354.99	-620.46	-26.35%	864.43	36.71%	(1,484.89)	-63.05%
1987 - 1989	2,966.86	1.00	0.03%	531.61	17.92%	(530.61)	-17.88%
1988 - 1990	2,848.28	1.00	0.04%	971.75	34.12%	(970.75)	-34.08%
1989 - 1991	5,898.07	1.00	0.02%	3,493.06	59.22%	(3,492.06)	-59.21%
1990 - 1992	8,236.50	0.00	0.00%	5,596.81	67.95%	(5,596.81)	-67.95%
1991 - 1993	10,830.32	0.00	0.00%	6,707.06	61.93%	(6,707.06)	-61.93%
1992 - 1994	12,762.28	0.00	0.00%	6,397.55	50.13%	(6,397.55)	-50.13%
1993 - 1995	9,053.10	4,904.42	54.17%	4,580.07	50.59%	324.35	3.58%
1994 - 1996	8,809.26	4,904.42	55.67%	7,686.20	87.25%	(2,781.78)	-31.58%
1995 - 1997	9,206.15	5,754.42	62.51%	5,731.40	62.26%	23.02	0.25%

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	9,109.25	850.00	9.33%	5,596.85	61.44%	(4,746.85)	-52.11%
1997 - 1999	6,440.96	850.00	13.20%	5,143.94	79.86%	(4,293.94)	-66.67%
1998 - 2000	4,503.16	1.00	0.02%	7,106.05	157.80%	(7,105.05)	-157.78%
1999 - 2001	5,139.03	1.00	0.02%	9,102.14	177.12%	(9,101.14)	-177.10%
2000 - 2002	4,684.34	1.00	0.02%	4,815.20	102.79%	(4,814.20)	-102.77%
2001 - 2003	1,236.50	0.00	0.00%	2,596.09	209.95%	(2,596.09)	-209.95%
2002 - 2004	8,596.99	0.00	0.00%	4,128.60	48.02%	(4,128.60)	-48.02%
2003 - 2005	8,596.99	0.00	0.00%	4,128.60	48.02%	(4,128.60)	-48.02%
2004 - 2006	11,867.12	0.00	0.00%	6,382.23	53.78%	(6,382.23)	-53.78%
2005 - 2007	3,720.13	0.00	0.00%	2,253.63	60.58%	(2,253.63)	-60.58%
2006 - 2008	5,672.82	0.00	0.00%	2,253.63	39.73%	(2,253.63)	-39.73%

Montana-Dakota Utilities Company
Gas Division
375.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 2008	97,369.35	12,745.62	13.09	38,160.21	39.19	(25,414.59)	-26.10

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	60.0
Average Retirement Age (Yrs)	32.7
Years To ASL	27.3
Inflation Factor At 2.75% to ASL	2.10

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	3.10%
1994-2008	**15 - Year Trend**	0.00% *
1999-2008	**10 - Year Trend**	0.00% *
2004-2008	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	82.21%
Net Salvage	-82.21%

Montana-Dakota Utilities Company
Gas Division
376.00, 376.10, 376.20, 376.30, 376.40, 376.50

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	200,220.26	16,598.28	8.29%	26,859.47	13.41%	(10,261.19)	-5.12%
1969	194,137.09	15,939.46	8.21%	43,168.49	22.24%	(27,229.03)	-14.03%
1970	267,046.03	23,230.21	8.70%	46,950.89	17.58%	(23,720.68)	-8.88%
1971	177,113.50	13,833.58	7.81%	56,809.25	32.08%	(42,975.67)	-24.26%
1972	157,195.80	13,435.85	8.55%	42,912.41	27.30%	(29,476.56)	-18.75%
1973	135,609.90	13,644.75	10.06%	27,848.00	20.54%	(14,203.25)	-10.47%
1974	79,682.47	4,158.86	5.22%	33,340.09	41.84%	(29,181.23)	-36.62%
1975	127,632.18	7,857.70	6.16%	43,072.35	33.75%	(35,214.65)	-27.59%
1976	195,879.62	9,760.39	4.98%	58,379.94	29.80%	(48,619.55)	-24.82%
1977	84,326.99	-3,773.39	-4.47%	25,097.78	29.76%	(28,871.17)	-34.24%
1978	116,364.42	10,832.09	9.31%	46,758.20	40.18%	(35,926.11)	-30.87%
1979	123,150.94	11,190.96	9.09%	36,244.68	29.43%	(25,053.72)	-20.34%
1980	88,516.03	3,479.59	3.93%	38,660.28	43.68%	(35,180.69)	-39.74%
1981	152,498.86	6,295.38	4.13%	46,691.72	30.62%	(40,396.34)	-26.49%
1982	127,572.66	-2,610.34	-2.05%	56,734.00	44.47%	(59,344.34)	-46.52%
1983	161,051.86	-581.14	-0.36%	104,094.70	64.63%	(104,675.84)	-65.00%
1984	185,619.78	-504.59	-0.27%	90,504.85	48.76%	(91,009.44)	-49.03%
1985	225.00	0.00	0.00%	94,130.78	1835.90%	(94,130.78)	-1835.90%
1986	164,397.14	-401.47	-0.24%	51,009.31	31.03%	(51,410.78)	-31.27%
1987	201,062.80	-231.86	-0.12%	90,443.45	44.98%	(90,675.31)	-45.10%
1988	281,758.55	-4,416.44	-1.57%	101,619.66	36.07%	(106,036.10)	-37.63%
1989	149,536.04	317.65	0.21%	69,598.16	46.54%	(69,280.51)	-46.33%
1990	92,157.64	-2,915.53	-3.16%	35,838.46	38.89%	(38,753.99)	-42.05%
1991	208,283.95	3,390.22	1.63%	72,574.40	34.84%	(69,184.18)	-33.22%
1992	261,776.43	-2,741.03	-1.05%	81,630.92	31.18%	(84,371.95)	-32.23%
1993	129,595.28	-3,971.17	-3.06%	60,124.58	46.39%	(64,095.75)	-49.46%
1994	362,204.01	-340.60	-0.09%	96,506.29	26.64%	(96,846.89)	-26.74%
1995	81,561.25	0.10	0.00%	22,341.68	27.39%	(22,341.58)	-27.39%

Montana-Dakota Utilities Company
Gas Division
376.00, 376.10, 376.20, 376.30, 376.40, 376.50

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Annual Activity							
1996	312,810.33	767.42	0.25%	83,391.55	26.66%	(82,624.13)	-26.41%
1997	182,351.81	56,675.22	31.08%	0.00	0.00%	56,675.22	31.08%
1998	196,796.74	805.67	0.41%	76,362.06	38.80%	(75,556.39)	-38.39%
1999	186,253.29	0.00	0.00%	82,439.31	44.26%	(82,439.31)	-44.26%
2000	158,497.94	0.00	0.00%	61,044.27	38.51%	(61,044.27)	-38.51%
2001	171,123.71	0.00	0.00%	74,109.60	43.31%	(74,109.60)	-43.31%
2002	118,946.90	0.00	0.00%	70,046.34	58.89%	(70,046.34)	-58.89%
2003	234,006.15	0.00	0.00%	150,701.69	64.40%	(150,701.69)	-64.40%
2004	390,887.97	0.00	0.00%	80,069.14	20.48%	(80,069.14)	-20.48%
2005	169,754.69	0.00	0.00%	57,360.40	33.79%	(57,360.40)	-33.79%
2006	122,131.96	804.98	0.66%	50,615.34	41.44%	(49,810.36)	-40.78%
2007	260,243.03	230.02	0.09%	85,572.48	32.88%	(85,342.46)	-32.79%
2008	443,390.53	155.02	0.03%	72,514.10	16.35%	(72,359.08)	-16.32%

Montana-Dakota Utilities Company
Gas Division
376.00, 376.10, 376.20, 376.30, 376.40, 376.50

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	661,403.38	55,767.95	8.43%	116,978.85	17.69%	(61,210.90)	-9.25%
1969 - 1971	638,296.62	53,003.25	8.30%	146,928.63	23.02%	(93,925.38)	-14.72%
1970 - 1972	601,355.33	50,499.64	8.40%	146,672.55	24.39%	(96,172.91)	-15.99%
1971 - 1973	469,919.20	40,914.18	8.71%	127,569.66	27.15%	(86,655.48)	-18.44%
1972 - 1974	372,488.17	31,239.46	8.39%	104,100.50	27.95%	(72,861.04)	-19.56%
1973 - 1975	342,924.55	25,661.31	7.48%	104,260.44	30.40%	(78,599.13)	-22.92%
1974 - 1976	403,194.27	21,776.95	5.40%	134,792.38	33.43%	(113,015.43)	-28.03%
1975 - 1977	407,838.79	13,844.70	3.39%	126,550.07	31.03%	(112,705.37)	-27.63%
1976 - 1978	396,571.03	16,819.09	4.24%	130,235.92	32.84%	(113,416.83)	-28.60%
1977 - 1979	323,842.35	18,249.66	5.64%	108,100.66	33.38%	(89,851.00)	-27.75%
1978 - 1980	328,031.39	25,502.64	7.77%	121,663.16	37.09%	(96,160.52)	-29.31%
1979 - 1981	364,165.83	20,965.93	5.76%	121,596.68	33.39%	(100,630.75)	-27.63%
1980 - 1982	368,587.55	7,164.63	1.94%	142,086.00	38.55%	(134,921.37)	-36.60%
1981 - 1983	441,123.38	3,103.90	0.70%	207,520.42	47.04%	(204,416.52)	-46.34%
1982 - 1984	474,244.30	-3,696.07	-0.78%	251,333.55	53.00%	(255,029.62)	-53.78%
1983 - 1985	346,896.64	-1,085.73	-0.31%	288,730.33	83.23%	(289,816.06)	-83.55%
1984 - 1986	350,241.92	-906.06	-0.26%	235,644.94	67.28%	(236,551.00)	-67.54%
1985 - 1987	365,684.94	-633.33	-0.17%	235,583.54	64.42%	(236,216.87)	-64.60%
1986 - 1988	647,218.49	-5,049.77	-0.78%	243,072.42	37.56%	(248,122.19)	-38.34%
1987 - 1989	632,357.39	-4,330.65	-0.68%	261,661.27	41.38%	(265,991.92)	-42.06%
1988 - 1990	523,452.23	-7,014.32	-1.34%	207,056.28	39.56%	(214,070.60)	-40.90%
1989 - 1991	449,977.63	792.34	0.18%	178,011.02	39.56%	(177,218.68)	-39.38%
1990 - 1992	562,218.02	-2,266.34	-0.40%	190,043.78	33.80%	(192,310.12)	-34.21%
1991 - 1993	599,655.66	-3,321.98	-0.55%	214,329.90	35.74%	(217,651.88)	-36.30%
1992 - 1994	753,575.72	-7,052.80	-0.94%	238,261.79	31.62%	(245,314.59)	-32.55%
1993 - 1995	573,360.54	-4,311.67	-0.75%	178,972.55	31.21%	(183,284.22)	-31.97%
1994 - 1996	756,575.59	426.92	0.06%	202,239.52	26.73%	(201,812.60)	-26.67%
1995 - 1997	576,723.39	57,442.74	9.96%	105,733.23	18.33%	(48,290.49)	-8.37%

Montana-Dakota Utilities Company
Gas Division
376.00, 376.10, 376.20, 376.30, 376.40, 376.50

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1996 - 1998	691,958.88	58,248.31	8.42%	159,753.61	23.09%	(101,505.30)	-14.67%
1997 - 1999	565,401.84	57,480.89	10.17%	158,801.37	28.09%	(101,320.48)	-17.92%
1998 - 2000	541,547.97	805.67	0.15%	219,845.64	40.60%	(219,039.97)	-40.45%
1999 - 2001	515,874.94	0.00	0.00%	217,593.18	42.18%	(217,593.18)	-42.18%
2000 - 2002	448,568.55	0.00	0.00%	205,200.21	45.75%	(205,200.21)	-45.75%
2001 - 2003	524,076.76	0.00	0.00%	294,857.63	56.26%	(294,857.63)	-56.26%
2002 - 2004	743,841.02	0.00	0.00%	300,817.17	40.44%	(300,817.17)	-40.44%
2003 - 2005	794,648.81	0.00	0.00%	288,131.23	36.26%	(288,131.23)	-36.26%
2004 - 2006	682,774.62	804.98	0.12%	188,044.88	27.54%	(187,239.90)	-27.42%
2005 - 2007	552,129.68	1,035.00	0.19%	193,548.22	35.05%	(192,513.22)	-34.87%
2006 - 2008	825,765.52	1,190.02	0.14%	208,701.92	25.27%	(207,511.90)	-25.13%

Montana-Dakota Utilities Company
Gas Division
376.00, 376.10, 376.20, 376.30, 376.40, 376.50

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1968 - 2008	7,453,371.53	190,915.84	2.56	2,544,171.07	34.13	(2,353,255.23)	-31.57

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	47.0
Average Retirement Age (Yrs)	10.2
Years To ASL	36.8
Inflation Factor At 2.75% to ASL	2.71

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	1.53%
1994-2008	**15 - Year Trend**	0.00% *
1999-2008	**10 - Year Trend**	0.00% *
2004-2008	**5 - Year Trend**	0.23%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.23%
Cost Of Removal	92.64%
Net Salvage	-92.41%

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	6,165.67	245.53	3.98%	384.57	6.24%	(139.04)	-2.26%
1969	5,072.04	681.64	13.44%	926.88	18.27%	(245.24)	-4.84%
1970	2,400.38	299.68	12.48%	794.84	33.11%	(495.16)	-20.63%
1971	5,953.07	1,423.90	23.92%	1,335.56	22.43%	88.34	1.48%
1972	8,537.76	1,548.78	18.14%	996.65	11.67%	552.13	6.47%
1973	4,721.42	136.76	2.90%	(230.17)	-4.88%	366.93	7.77%
1974	7,786.40	934.98	12.01%	1,803.46	23.16%	(868.48)	-11.15%
1975	5,798.87	1,131.96	19.52%	1,811.88	31.25%	(679.92)	-11.73%
1976	9,370.41	1,641.73	17.52%	850.97	9.08%	790.76	8.44%
1977	9,211.09	2,097.50	22.77%	1,860.19	20.20%	237.31	2.58%
1978	7,880.15	1,956.75	24.83%	1,742.60	22.11%	214.15	2.72%
1979	4,423.45	694.41	15.70%	2,237.76	50.59%	(1,543.35)	-34.89%
1980	11,750.95	11,103.62	94.49%	2,645.90	22.52%	8,457.72	71.97%
1981	2,893.54	856.15	29.59%	386.70	13.36%	469.45	16.22%
1982	3,107.26	1,493.08	48.05%	3,757.57	120.93%	(2,264.49)	-72.88%
1983	15,302.51	4,641.93	30.33%	3,904.22	25.51%	737.71	4.82%
1984	7,769.09	5,792.53	74.56%	945.55	12.17%	4,846.98	62.39%
1985	152,087.98	0.00	0.00%	1,598.99	1.05%	(1,598.99)	-1.05%
1986	6,028.86	3,133.32	51.97%	1,178.98	19.56%	1,954.34	32.42%
1987	4,864.25	1,168.80	24.03%	608.41	12.51%	560.39	11.52%
1988	17,936.07	8,021.93	44.73%	3,187.18	17.77%	4,834.75	26.96%
1989	11,708.76	2,017.11	17.23%	2,832.97	24.20%	(815.86)	-6.97%
1990	3,904.28	1,256.18	32.17%	977.17	25.03%	279.01	7.15%
1991	5,145.64	868.70	16.88%	1,939.74	37.70%	(1,071.04)	-20.81%
1992	14,934.74	1,870.26	12.52%	4,119.48	27.58%	(2,249.22)	-15.06%
1993	5,076.89	671.04	13.22%	65.67	1.29%	605.37	11.92%
1994	53,564.31	6,804.16	12.70%	4,545.24	8.49%	2,258.92	4.22%
1995	3,767.18	4,785.35	127.03%	4,926.89	130.78%	(141.54)	-3.76%

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	23,029.73	4,351.90	18.90%	10,141.37	44.04%	(5,789.47)	-25.14%
1997	16,951.86	712.79	4.20%	8,056.88	47.53%	(7,344.09)	-43.32%
1998	17,131.15	1,482.18	8.65%	8,754.03	51.10%	(7,271.85)	-42.45%
1999	3,292.16	0.00	0.00%	749.36	22.76%	(749.36)	-22.76%
2000	11,156.50	962.68	8.63%	6,839.22	61.30%	(5,876.54)	-52.67%
2001	8,696.02	2,153.63	24.77%	6,139.17	70.60%	(3,985.54)	-45.83%
2002	7,083.00	0.00	0.00%	939.67	13.27%	(939.67)	-13.27%
2003	10,744.38	0.00	0.00%	16,774.97	156.13%	(16,774.97)	-156.13%
2004	16,732.36	0.00	0.00%	3,678.39	21.98%	(3,678.39)	-21.98%
2005	8,182.35	0.00	0.00%	2,304.18	28.16%	(2,304.18)	-28.16%
2006	2,239.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	22,625.76	0.00	0.00%	913.41	4.04%	(913.41)	-4.04%
2008	17,733.46	0.00	0.00%	850.20	4.79%	(850.20)	-4.79%

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	13,638.09	1,226.85	9.00%	2,106.29	15.44%	(879.44)	-6.45%
1969 - 1971	13,425.49	2,405.22	17.92%	3,057.28	22.77%	(652.06)	-4.86%
1970 - 1972	16,891.21	3,272.36	19.37%	3,127.05	18.51%	145.31	0.86%
1971 - 1973	19,212.25	3,109.44	16.18%	2,102.04	10.94%	1,007.40	5.24%
1972 - 1974	21,045.58	2,620.52	12.45%	2,569.94	12.21%	50.58	0.24%
1973 - 1975	18,306.69	2,203.70	12.04%	3,385.17	18.49%	(1,181.47)	-6.45%
1974 - 1976	22,955.68	3,708.67	16.16%	4,466.31	19.46%	(757.64)	-3.30%
1975 - 1977	24,380.37	4,871.19	19.98%	4,523.04	18.55%	348.15	1.43%
1976 - 1978	26,461.65	5,695.98	21.53%	4,453.76	16.83%	1,242.22	4.69%
1977 - 1979	21,514.69	4,748.66	22.07%	5,840.55	27.15%	(1,091.89)	-5.08%
1978 - 1980	24,054.55	13,754.78	57.18%	6,626.26	27.55%	7,128.52	29.63%
1979 - 1981	19,067.94	12,654.18	66.36%	5,270.36	27.64%	7,383.82	38.72%
1980 - 1982	17,751.75	13,452.85	75.78%	6,790.17	38.25%	6,662.68	37.53%
1981 - 1983	21,303.31	6,991.16	32.82%	8,048.49	37.78%	(1,057.33)	-4.96%
1982 - 1984	26,178.86	11,927.54	45.56%	8,607.34	32.88%	3,320.20	12.68%
1983 - 1985	175,159.58	10,434.46	5.96%	6,448.76	3.68%	3,985.70	2.28%
1984 - 1986	165,885.93	8,925.85	5.38%	3,723.52	2.24%	5,202.33	3.14%
1985 - 1987	162,981.09	4,302.12	2.64%	3,386.38	2.08%	915.74	0.56%
1986 - 1988	28,829.18	12,324.05	42.75%	4,974.57	17.26%	7,349.48	25.49%
1987 - 1989	34,509.08	11,207.84	32.48%	6,628.56	19.21%	4,579.28	13.27%
1988 - 1990	33,549.11	11,295.22	33.67%	6,997.32	20.86%	4,297.90	12.81%
1989 - 1991	20,758.68	4,141.99	19.95%	5,749.88	27.70%	(1,607.89)	-7.75%
1990 - 1992	23,984.66	3,995.14	16.66%	7,036.39	29.34%	(3,041.25)	-12.68%
1991 - 1993	25,157.27	3,410.00	13.55%	6,124.89	24.35%	(2,714.89)	-10.79%
1992 - 1994	73,575.94	9,345.46	12.70%	8,730.39	11.87%	615.07	0.84%
1993 - 1995	62,408.38	12,260.55	19.65%	9,537.80	15.28%	2,722.75	4.36%
1994 - 1996	80,361.22	15,941.41	19.84%	19,613.50	24.41%	(3,672.09)	-4.57%
1995 - 1997	43,748.77	9,850.04	22.52%	23,125.14	52.86%	(13,275.10)	-30.34%

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	57,112.74	6,546.87	11.46%	26,952.28	47.19%	(20,405.41)	-35.73%
1997 - 1999	37,375.17	2,194.97	5.87%	17,560.27	46.98%	(15,365.30)	-41.11%
1998 - 2000	31,579.81	2,444.86	7.74%	16,342.61	51.75%	(13,897.75)	-44.01%
1999 - 2001	23,144.68	3,116.31	13.46%	13,727.75	59.31%	(10,611.44)	-45.85%
2000 - 2002	26,935.52	3,116.31	11.57%	13,918.06	51.67%	(10,801.75)	-40.10%
2001 - 2003	26,523.40	2,153.63	8.12%	23,853.81	89.93%	(21,700.18)	-81.82%
2002 - 2004	34,559.74	0.00	0.00%	21,393.03	61.90%	(21,393.03)	-61.90%
2003 - 2005	35,659.09	0.00	0.00%	22,757.54	63.82%	(22,757.54)	-63.82%
2004 - 2006	27,153.71	0.00	0.00%	5,982.57	22.03%	(5,982.57)	-22.03%
2005 - 2007	33,047.11	0.00	0.00%	3,217.59	9.74%	(3,217.59)	-9.74%
2006 - 2008	42,598.22	0.00	0.00%	1,763.61	4.14%	(1,763.61)	-4.14%

Montana-Dakota Utilities Company
Gas Division
378.00 MEAS. & REG. STATION EQUIP. - GENERAL
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 2008	562,760.75	76,940.96	13.67	118,276.70	21.02	(41,335.74)	-7.35

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	40.0
Average Retirement Age (Yrs)	15.9
Years To ASL	24.1
Inflation Factor At 2.75% to ASL	1.92

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	0.00% *
1994-2008	**15 - Year Trend**	0.00% *
1999-2008	**10 - Year Trend**	0.00% *
2004-2008	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	40.37%
Net Salvage	-40.37%

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	18,414.18	5,785.41	31.42%	1,569.21	8.52%	4,216.20	22.90%
1969	16,569.97	4,369.23	26.37%	1,184.86	7.15%	3,184.37	19.22%
1970	13,735.04	3,662.00	26.66%	1,070.13	7.79%	2,591.87	18.87%
1971	8,371.34	2,075.36	24.79%	1,671.45	19.97%	403.91	4.82%
1972	30,257.72	6,523.51	21.56%	1,473.77	4.87%	5,049.74	16.69%
1973	5,526.84	2,274.92	41.16%	1,090.31	19.73%	1,184.61	21.43%
1974	6,833.15	879.07	12.86%	609.12	8.91%	269.95	3.95%
1975	3,276.17	851.21	25.98%	824.83	25.18%	26.38	0.81%
1976	5,133.75	2,898.47	56.46%	954.06	18.58%	1,944.41	37.88%
1977	1,235.92	386.35	31.26%	435.84	35.26%	(49.49)	-4.00%
1978	8,311.82	2,644.04	31.81%	2,548.00	30.66%	96.04	1.16%
1979	2,493.74	874.25	35.06%	226.52	9.08%	647.73	25.97%
1980	4,989.43	2,200.37	44.10%	308.90	6.19%	1,891.47	37.91%
1981	19,759.99	11,981.07	60.63%	4,298.58	21.75%	7,682.49	38.88%
1982	15,342.56	7,067.64	46.07%	1,787.32	11.65%	5,280.32	34.42%
1983	5,370.15	7,646.09	142.38%	896.74	16.70%	6,749.35	125.68%
1984	11,813.59	4,661.41	39.46%	1,805.26	15.28%	2,856.15	24.18%
1985	20,078.95	4,189.55	20.87%	0.00	0.00%	4,189.55	20.87%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	240.01	0.00	0.00%	56.84	23.68%	(56.84)	-23.68%
1988	3,178.76	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	565.28	109.81	19.43%	41.97	7.42%	67.84	12.00%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	6,702.82	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	225.00	0.00	0.00%	23.32	10.36%	(23.32)	-10.36%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	24,000.34	6,121.69	25.51%	248.40	1.03%	5,873.29	24.47%
1995	1,429.24	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	0.00	375.00	0.00%	0.00	0.00%	375.00	0.00%
1997	19,117.83	3,723.12	19.47%	845.73	4.42%	2,877.39	15.05%
1998	2,593.97	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	1,744.33	0.00	0.00%	279.93	16.05%	(279.93)	-16.05%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	4,387.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	1,470.33	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	8,335.08	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	48,719.19	13,816.64	28.36%	3,824.20	7.85%	9,992.44	20.51%
1969 - 1971	38,676.35	10,106.59	26.13%	3,926.44	10.15%	6,180.15	15.98%
1970 - 1972	52,364.10	12,260.87	23.41%	4,215.35	8.05%	8,045.52	15.36%
1971 - 1973	44,155.90	10,873.79	24.63%	4,235.53	9.59%	6,638.26	15.03%
1972 - 1974	42,617.71	9,677.50	22.71%	3,173.20	7.45%	6,504.30	15.26%
1973 - 1975	15,636.16	4,005.20	25.61%	2,524.26	16.14%	1,480.94	9.47%
1974 - 1976	15,243.07	4,628.75	30.37%	2,388.01	15.67%	2,240.74	14.70%
1975 - 1977	9,645.84	4,136.03	42.88%	2,214.73	22.96%	1,921.30	19.92%
1976 - 1978	14,681.49	5,928.86	40.38%	3,937.90	26.82%	1,990.96	13.56%
1977 - 1979	12,041.48	3,904.64	32.43%	3,210.36	26.66%	694.28	5.77%
1978 - 1980	15,794.99	5,718.66	36.21%	3,083.42	19.52%	2,635.24	16.68%
1979 - 1981	27,243.16	15,055.69	55.26%	4,834.00	17.74%	10,221.69	37.52%
1980 - 1982	40,091.98	21,249.08	53.00%	6,394.80	15.95%	14,854.28	37.05%
1981 - 1983	40,472.70	26,694.80	65.96%	6,982.64	17.25%	19,712.16	48.70%
1982 - 1984	32,526.30	19,375.14	59.57%	4,489.32	13.80%	14,885.82	45.77%
1983 - 1985	37,262.69	16,497.05	44.27%	2,702.00	7.25%	13,795.05	37.02%
1984 - 1986	31,892.54	8,850.96	27.75%	1,805.26	5.66%	7,045.70	22.09%
1985 - 1987	20,318.96	4,189.55	20.62%	56.84	0.28%	4,132.71	20.34%
1986 - 1988	3,418.77	0.00	0.00%	56.84	1.66%	(56.84)	-1.66%
1987 - 1989	3,984.05	109.81	2.76%	98.81	2.48%	11.00	0.28%
1988 - 1990	3,744.04	109.81	2.93%	41.97	1.12%	67.84	1.81%
1989 - 1991	7,268.10	109.81	1.51%	41.97	0.58%	67.84	0.93%
1990 - 1992	6,927.82	0.00	0.00%	23.32	0.34%	(23.32)	-0.34%
1991 - 1993	6,927.82	0.00	0.00%	23.32	0.34%	(23.32)	-0.34%
1992 - 1994	24,225.34	6,121.69	25.27%	271.72	1.12%	5,849.97	24.15%
1993 - 1995	25,429.58	6,121.69	24.07%	248.40	0.98%	5,873.29	23.10%
1994 - 1996	25,429.58	6,496.69	25.55%	248.40	0.98%	6,248.29	24.57%
1995 - 1997	20,547.07	4,098.12	19.95%	845.73	4.12%	3,252.39	15.83%

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	21,711.80	4,098.12	18.88%	845.73	3.90%	3,252.39	14.98%
1997 - 1999	23,456.13	3,723.12	15.87%	1,125.66	4.80%	2,597.46	11.07%
1998 - 2000	4,338.30	0.00	0.00%	279.93	6.45%	(279.93)	-6.45%
1999 - 2001	1,744.33	0.00	0.00%	279.93	16.05%	(279.93)	-16.05%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	4,387.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	5,857.74	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	5,857.74	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	1,470.33	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005 - 2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	8,335.08	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
379.00 MEAS. & REG. STATION EQUIP. - CITY GATE
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1968 - 2008	271,504.71	81,299.57	29.94	24,251.09	8.93	57,048.48	21.01

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	27.0
Average Retirement Age (Yrs)	27.2
Years To ASL	-0.2
Inflation Factor At 2.75% to ASL	1.00

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	1.22%
1994-2008	**15 - Year Trend**	0.00% *
1999-2008	**10 - Year Trend**	0.00% *
2004-2008	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	8.89%
Net Salvage	-8.89%

Montana-Dakota Utilities Company
Gas Division
380.00, 380.10, 380.20, 380.30
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	58,055.53	3,059.40	5.27%	27,723.99	47.75%	(24,664.59)	-42.48%
1969	55,853.48	845.59	1.51%	26,200.12	46.91%	(25,354.53)	-45.39%
1970	78,879.56	530.18	0.67%	23,001.10	29.16%	(22,470.92)	-28.49%
1971	52,774.35	880.28	1.67%	35,729.03	67.70%	(34,848.75)	-66.03%
1972	79,522.93	697.12	0.88%	32,010.82	40.25%	(31,313.70)	-39.38%
1973	65,093.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	64,653.14	596.73	0.92%	49,546.52	76.63%	(48,949.79)	-75.71%
1975	37,754.54	2,843.03	7.53%	50,159.99	132.86%	(47,316.96)	-125.33%
1976	68,213.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	192,462.86	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	-92,938.46	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	55,534.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	61,494.60	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	63,423.25	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	84,858.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	73,868.72	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	95,311.04	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	33,968.77	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	82,204.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	102,945.66	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	130,255.01	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	103,193.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990	87,093.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	112,288.21	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	152,087.98	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	117,390.79	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	213,594.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	85,394.58	238.78	0.28%	132,997.10	155.74%	(132,758.32)	-155.46%

Montana-Dakota Utilities Company
Gas Division
380.00, 380.10, 380.20, 380.30

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	190,887.20	489.25	0.26%	196,474.55	102.93%	(195,985.30)	-102.67%
1997	147,018.12	274.30	0.19%	167,867.03	114.18%	(167,592.73)	-113.99%
1998	156,868.35	165.57	0.11%	232,839.48	148.43%	(232,673.91)	-148.32%
1999	129,801.17	0.00	0.00%	205,972.55	158.68%	(205,972.55)	-158.68%
2000	134,394.03	0.00	0.00%	200,260.66	149.01%	(200,260.66)	-149.01%
2001	123,831.18	31.47	0.03%	203,228.57	164.12%	(203,197.10)	-164.09%
2002	95,019.90	0.00	0.00%	198,438.09	208.84%	(198,438.09)	-208.84%
2003	163,649.47	2,265.98	1.38%	269,303.25	164.56%	(267,037.27)	-163.18%
2004	184,931.55	0.00	0.00%	371,150.10	200.70%	(371,150.10)	-200.70%
2005	91,049.72	78.72	0.09%	257,936.56	283.29%	(257,857.84)	-283.21%
2006	107,041.95	275.02	0.26%	265,998.27	248.50%	(265,723.25)	-248.24%
2007	173,205.75	46.31	0.03%	367,375.64	212.10%	(367,329.33)	-212.08%
2008	112,617.91	461.23	0.41%	322,738.26	286.58%	(322,277.03)	-286.17%

Montana-Dakota Utilities Company

Gas Division

380.00, 380.10, 380.20, 380.30

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	192,788.57	4,435.17	2.30%	76,925.21	39.90%	(72,490.04)	-37.60%
1969 - 1971	187,507.39	2,256.05	1.20%	84,930.25	45.29%	(82,674.20)	-44.09%
1970 - 1972	211,176.84	2,107.58	1.00%	90,740.95	42.97%	(88,633.37)	-41.97%
1971 - 1973	197,390.71	1,577.40	0.80%	67,739.85	34.32%	(66,162.45)	-33.52%
1972 - 1974	209,269.50	1,293.85	0.62%	81,557.34	38.97%	(80,263.49)	-38.35%
1973 - 1975	167,501.11	3,439.76	2.05%	99,706.51	59.53%	(96,266.75)	-57.47%
1974 - 1976	170,621.43	3,439.76	2.02%	99,706.51	58.44%	(96,266.75)	-56.42%
1975 - 1977	298,431.15	2,843.03	0.95%	50,159.99	16.81%	(47,316.96)	-15.86%
1976 - 1978	167,738.15	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977 - 1979	155,058.81	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978 - 1980	24,090.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979 - 1981	180,452.26	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	209,776.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	222,150.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	254,038.32	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	203,148.53	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	211,483.84	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	219,118.46	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986 - 1988	315,404.70	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987 - 1989	336,394.22	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988 - 1990	320,542.31	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989 - 1991	302,575.51	0.00	0.00%	0.00	0.00%	0.00	0.00%
1990 - 1992	351,469.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	381,766.98	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	483,073.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	416,380.12	238.78	0.06%	132,997.10	31.94%	(132,758.32)	-31.88%
1994 - 1996	489,876.53	728.03	0.15%	329,471.65	67.26%	(328,743.62)	-67.11%
1995 - 1997	423,299.90	1,002.33	0.24%	497,338.68	117.49%	(496,336.35)	-117.25%

Montana-Dakota Utilities Company
Gas Division
380.00, 380.10, 380.20, 380.30

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	494,773.67	929.12	0.19%	597,181.06	120.70%	(596,251.94)	-120.51%
1997 - 1999	433,687.64	439.87	0.10%	606,679.06	139.89%	(606,239.19)	-139.79%
1998 - 2000	421,063.55	165.57	0.04%	639,072.69	151.78%	(638,907.12)	-151.74%
1999 - 2001	388,026.38	31.47	0.01%	609,461.78	157.07%	(609,430.31)	-157.06%
2000 - 2002	353,245.11	31.47	0.01%	601,927.32	170.40%	(601,895.85)	-170.39%
2001 - 2003	382,500.55	2,297.45	0.60%	670,969.91	175.42%	(668,672.46)	-174.82%
2002 - 2004	443,600.92	2,265.98	0.51%	838,891.44	189.11%	(836,625.46)	-188.60%
2003 - 2005	439,630.74	2,344.70	0.53%	898,389.91	204.35%	(896,045.21)	-203.82%
2004 - 2006	383,023.22	353.74	0.09%	895,084.93	233.69%	(894,731.19)	-233.60%
2005 - 2007	371,297.42	400.05	0.11%	891,310.47	240.05%	(890,910.42)	-239.95%
2006 - 2008	392,865.61	782.56	0.20%	956,112.17	243.37%	(955,329.61)	-243.17%

Montana-Dakota Utilities Company
Gas Division
380.00, 380.10, 380.20, 380.30

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1968 - 2008	4,125,549.07	13,778.96	0.33	3,636,951.68	88.16	(3,623,172.72)	-87.82

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	40.0
Average Retirement Age (Yrs)	8.0
Years To ASL	32.0
Inflation Factor At 2.75% to ASL	2.38

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	0.33%
1994-2008	**15 - Year Trend**	0.32%
1999-2008	**10 - Year Trend**	0.33%
2004-2008	**5 - Year Trend**	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	209.83%
Net Salvage	-209.83%

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	89,621.05	20,853.15	23.27%	100.61	0.11%	20,752.54	23.16%
1969	88,141.67	21,175.77	24.02%	4.76	0.01%	21,171.01	24.02%
1970	84,232.62	22,634.02	26.87%	0.00	0.00%	22,634.02	26.87%
1971	113,603.29	45,459.80	40.02%	0.00	0.00%	45,459.80	40.02%
1972	104,367.42	28,705.75	27.50%	5.00	0.00%	28,700.75	27.50%
1973	103,144.67	33,345.95	32.33%	0.00	0.00%	33,345.95	32.33%
1974	102,736.09	52,118.35	50.73%	0.00	0.00%	52,118.35	50.73%
1975	165,635.60	63,047.92	38.06%	0.00	0.00%	63,047.92	38.06%
1976	135,627.82	59,618.84	43.96%	0.00	0.00%	59,618.84	43.96%
1977	71,937.22	25,174.11	34.99%	0.00	0.00%	25,174.11	34.99%
1978	131,277.92	52,316.96	39.85%	0.00	0.00%	52,316.96	39.85%
1979	148,233.80	64,025.07	43.19%	(43.43)	-0.03%	64,068.50	43.22%
1980	305,397.80	208,883.27	68.40%	77.59	0.03%	208,805.68	68.37%
1981	126,975.53	50,478.48	39.75%	0.00	0.00%	50,478.48	39.75%
1982	154,079.01	35,126.16	22.80%	(167.28)	-0.11%	35,293.44	22.91%
1983	162,477.00	27,158.04	16.72%	(22.73)	-0.01%	27,180.77	16.73%
1984	271,430.65	51,182.92	18.86%	0.00	0.00%	51,182.92	18.86%
1985	5,915.92	-700.00	-11.83%	0.00	0.00%	(700.00)	-11.83%
1986	120,997.42	22,771.82	18.82%	0.00	0.00%	22,771.82	18.82%
1987	113,329.32	19,829.78	17.50%	0.00	0.00%	19,829.78	17.50%
1988	133,122.11	20,425.53	15.34%	0.00	0.00%	20,425.53	15.34%
1989	118,174.74	16,855.60	14.26%	0.00	0.00%	16,855.60	14.26%
1990	74,744.83	6,283.18	8.41%	0.00	0.00%	6,283.18	8.41%
1991	80,430.53	2,892.22	3.60%	0.00	0.00%	2,892.22	3.60%
1992	106,428.89	2,245.90	2.11%	0.00	0.00%	2,245.90	2.11%
1993	86,460.76	4,464.18	5.16%	0.00	0.00%	4,464.18	5.16%
1994	140,444.26	4,954.94	3.53%	28.34	0.02%	4,926.60	3.51%
1995	265,413.57	140.83	0.05%	0.00	0.00%	140.83	0.05%

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	143,875.77	8,202.93	5.70%	0.00	0.00%	8,202.93	5.70%
1997	163,997.79	3,569.20	2.18%	0.00	0.00%	3,569.20	2.18%
1998	167,984.94	395.20	0.24%	0.00	0.00%	395.20	0.24%
1999	105,617.04	1,111.77	1.05%	0.00	0.00%	1,111.77	1.05%
2000	82,561.94	12,514.29	15.16%	0.00	0.00%	12,514.29	15.16%
2001	417,486.88	3,201.41	0.77%	92,372.21	22.13%	(89,170.80)	-21.36%
2002	1,907.40	755.86	39.63%	78.00	4.09%	677.86	35.54%
2003	13,397.63	10,850.29	80.99%	837.73	6.25%	10,012.56	74.73%
2004	29,662.11	13,191.45	44.47%	6,515.30	21.97%	6,676.15	22.51%
2005	1,342,411.55	35,501.30	2.64%	418,681.00	31.19%	(383,179.70)	-28.54%
2006	46,151.70	29,808.13	64.59%	6,552.00	14.20%	23,256.13	50.39%
2007	569,985.49	11,103.05	1.95%	0.00	0.00%	11,103.05	1.95%
2008	53,910.77	48,607.78	90.16%	143,105.00	265.45%	(94,497.22)	-175.28%

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1968 - 1970	261,995.34	64,662.94	24.68%	105.37	0.04%	64,557.57	24.64%
1969 - 1971	285,977.58	89,269.59	31.22%	4.76	0.00%	89,264.83	31.21%
1970 - 1972	302,203.33	96,799.57	32.03%	5.00	0.00%	96,794.57	32.03%
1971 - 1973	321,115.38	107,511.50	33.48%	5.00	0.00%	107,506.50	33.48%
1972 - 1974	310,248.18	114,170.05	36.80%	5.00	0.00%	114,165.05	36.80%
1973 - 1975	371,516.36	148,512.22	39.97%	0.00	0.00%	148,512.22	39.97%
1974 - 1976	403,999.51	174,785.11	43.26%	0.00	0.00%	174,785.11	43.26%
1975 - 1977	373,200.64	147,840.87	39.61%	0.00	0.00%	147,840.87	39.61%
1976 - 1978	338,842.96	137,109.91	40.46%	0.00	0.00%	137,109.91	40.46%
1977 - 1979	351,448.94	141,516.14	40.27%	(43.43)	-0.01%	141,559.57	40.28%
1978 - 1980	584,909.52	325,225.30	55.60%	34.16	0.01%	325,191.14	55.60%
1979 - 1981	580,607.13	323,386.82	55.70%	34.16	0.01%	323,352.66	55.69%
1980 - 1982	586,452.34	294,487.91	50.22%	(89.69)	-0.02%	294,577.60	50.23%
1981 - 1983	443,531.54	112,762.68	25.42%	(190.01)	-0.04%	112,952.69	25.47%
1982 - 1984	587,986.66	113,467.12	19.30%	(190.01)	-0.03%	113,657.13	19.33%
1983 - 1985	439,823.57	77,640.96	17.65%	(22.73)	-0.01%	77,663.69	17.66%
1984 - 1986	398,343.99	73,254.74	18.39%	0.00	0.00%	73,254.74	18.39%
1985 - 1987	240,242.66	41,901.60	17.44%	0.00	0.00%	41,901.60	17.44%
1986 - 1988	367,448.85	63,027.13	17.15%	0.00	0.00%	63,027.13	17.15%
1987 - 1989	364,626.17	57,110.91	15.66%	0.00	0.00%	57,110.91	15.66%
1988 - 1990	326,041.68	43,564.31	13.36%	0.00	0.00%	43,564.31	13.36%
1989 - 1991	273,350.10	26,031.00	9.52%	0.00	0.00%	26,031.00	9.52%
1990 - 1992	261,604.25	11,421.30	4.37%	0.00	0.00%	11,421.30	4.37%
1991 - 1993	273,320.18	9,602.30	3.51%	0.00	0.00%	9,602.30	3.51%
1992 - 1994	333,333.91	11,665.02	3.50%	28.34	0.01%	11,636.68	3.49%
1993 - 1995	492,318.59	9,559.95	1.94%	28.34	0.01%	9,531.61	1.94%
1994 - 1996	549,733.60	13,298.70	2.42%	28.34	0.01%	13,270.36	2.41%
1995 - 1997	573,287.13	11,912.96	2.08%	0.00	0.00%	11,912.96	2.08%

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1996 - 1998	475,858.50	12,167.33	2.56%	0.00	0.00%	12,167.33	2.56%
1997 - 1999	437,599.77	5,076.17	1.16%	0.00	0.00%	5,076.17	1.16%
1998 - 2000	356,163.92	14,021.26	3.94%	0.00	0.00%	14,021.26	3.94%
1999 - 2001	605,665.86	16,827.47	2.78%	92,372.21	15.25%	(75,544.74)	-12.47%
2000 - 2002	501,956.22	16,471.56	3.28%	92,450.21	18.42%	(75,978.65)	-15.14%
2001 - 2003	432,791.91	14,807.56	3.42%	93,287.94	21.55%	(78,480.38)	-18.13%
2002 - 2004	44,967.14	24,797.60	55.15%	7,431.03	16.53%	17,366.57	38.62%
2003 - 2005	1,385,471.29	59,543.04	4.30%	426,034.03	30.75%	(366,490.99)	-26.45%
2004 - 2006	1,418,225.36	78,500.88	5.54%	431,748.30	30.44%	(353,247.42)	-24.91%
2005 - 2007	1,958,548.74	76,412.48	3.90%	425,233.00	21.71%	(348,820.52)	-17.81%
2006 - 2008	670,047.96	89,518.96	13.36%	149,657.00	22.34%	(60,138.04)	-8.98%

Montana-Dakota Utilities Company
Gas Division
381.00 METERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1968 - 2008	6,743,332.52	1,140,281.20	16.91	668,124.10	9.91	472,157.10	7.00

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	35.0
Average Retirement Age (Yrs)	11.7
Years To ASL	23.3
Inflation Factor At 2.75% to ASL	1.88

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	10.29%
1994-2008	**15 - Year Trend**	14.91%
1999-2008	**10 - Year Trend**	15.62%
2004-2008	**5 - Year Trend**	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	18.66%
Net Salvage	-18.66%

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	10,480.51	1,798.17	17.16%	0.00	0.00%	1,798.17	17.16%
1969	15,625.37	1,952.40	12.50%	0.00	0.00%	1,952.40	12.50%
1970	7,948.48	2,721.43	34.24%	0.00	0.00%	2,721.43	34.24%
1971	13,967.47	1,582.76	11.33%	0.00	0.00%	1,582.76	11.33%
1972	19,005.32	5,947.81	31.30%	51.06	0.27%	5,896.75	31.03%
1973	19,824.36	7,979.91	40.25%	0.00	0.00%	7,979.91	40.25%
1974	16,485.63	2,951.77	17.91%	0.00	0.00%	2,951.77	17.91%
1975	18,650.29	13,618.89	73.02%	0.00	0.00%	13,618.89	73.02%
1976	22,731.51	7,934.37	34.90%	131.40	0.58%	7,802.97	34.33%
1977	11,250.78	3,332.87	29.62%	78.30	0.70%	3,254.57	28.93%
1978	13,280.23	3,807.19	28.67%	9.58	0.07%	3,797.61	28.60%
1979	16,135.49	6,063.67	37.58%	0.00	0.00%	6,063.67	37.58%
1980	17,812.86	5,072.17	28.47%	76.60	0.43%	4,995.57	28.04%
1981	18,881.47	2,694.22	14.27%	26.37	0.14%	2,667.85	14.13%
1982	31,214.62	3,046.01	9.76%	0.00	0.00%	3,046.01	9.76%
1983	34,299.20	4,938.52	14.40%	0.00	0.00%	4,938.52	14.40%
1984	54,363.07	4,955.13	9.11%	0.00	0.00%	4,955.13	9.11%
1985	31,528.72	-220.00	-0.70%	96.12	0.30%	(316.12)	-1.00%
1986	26,481.25	6,050.68	22.85%	0.00	0.00%	6,050.68	22.85%
1987	28,723.49	3,727.71	12.98%	836.11	2.91%	2,891.60	10.07%
1988	37,400.09	4,520.88	12.09%	668.31	1.79%	3,852.57	10.30%
1989	37,255.58	3,404.35	9.14%	0.00	0.00%	3,404.35	9.14%
1990	45,689.19	2,229.08	4.88%	0.00	0.00%	2,229.08	4.88%
1991	51,279.08	4,323.62	8.43%	173.62	0.34%	4,150.00	8.09%
1992	33,968.77	6,837.93	20.13%	0.00	0.00%	6,837.93	20.13%
1993	35,131.57	3,569.60	10.16%	0.00	0.00%	3,569.60	10.16%
1994	35,847.05	3,465.08	9.67%	0.00	0.00%	3,465.08	9.67%
1995	38,394.60	378.34	0.99%	0.00	0.00%	378.34	0.99%

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	55,447.33	10,698.81	19.30%	737.81	1.33%	9,961.00	17.96%
1997	16,405.83	7,613.53	46.41%	0.00	0.00%	7,613.53	46.41%
1998	30,249.00	1,656.02	5.47%	0.00	0.00%	1,656.02	5.47%
1999	887.29	2,804.86	316.12%	0.00	0.00%	2,804.86	316.12%
2000	3,372.89	5,066.21	150.20%	72.07	2.14%	4,994.14	148.07%
2001	22,146.01	1,874.12	8.46%	0.00	0.00%	1,874.12	8.46%
2002	5,255.00	717.47	13.65%	0.00	0.00%	717.47	13.65%
2003	11,656.19	2,539.24	21.78%	0.00	0.00%	2,539.24	21.78%
2004	3,291.86	2,286.71	69.47%	0.00	0.00%	2,286.71	69.47%
2005	18.93	4,479.02	23660.96%	0.00	0.00%	4,479.02	:3660.96%
2006	1,838.43	8,134.94	442.49%	0.00	0.00%	8,134.94	442.49%
2007	273.27	5,843.89	2138.50%	0.00	0.00%	5,843.89	2138.50%
2008	7,275.67	11,579.04	159.15%	745.37	10.24%	10,833.67	148.90%

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1968 - 1970	34,054.36	6,472.00	19.00%	0.00	0.00%	6,472.00	19.00%
1969 - 1971	37,541.32	6,256.59	16.67%	0.00	0.00%	6,256.59	16.67%
1970 - 1972	40,921.27	10,252.00	25.05%	51.06	0.12%	10,200.94	24.93%
1971 - 1973	52,797.15	15,510.48	29.38%	51.06	0.10%	15,459.42	29.28%
1972 - 1974	55,315.31	16,879.49	30.52%	51.06	0.09%	16,828.43	30.42%
1973 - 1975	54,960.28	24,550.57	44.67%	0.00	0.00%	24,550.57	44.67%
1974 - 1976	57,867.43	24,505.03	42.35%	131.40	0.23%	24,373.63	42.12%
1975 - 1977	52,632.58	24,886.13	47.28%	209.70	0.40%	24,676.43	46.88%
1976 - 1978	47,262.52	15,074.43	31.90%	219.28	0.46%	14,855.15	31.43%
1977 - 1979	40,666.50	13,203.73	32.47%	87.88	0.22%	13,115.85	32.25%
1978 - 1980	47,228.58	14,943.03	31.64%	86.18	0.18%	14,856.85	31.46%
1979 - 1981	52,829.82	13,830.06	26.18%	102.97	0.19%	13,727.09	25.98%
1980 - 1982	67,908.95	10,812.40	15.92%	102.97	0.15%	10,709.43	15.77%
1981 - 1983	84,395.29	10,678.75	12.65%	26.37	0.03%	10,652.38	12.62%
1982 - 1984	119,876.89	12,939.66	10.79%	0.00	0.00%	12,939.66	10.79%
1983 - 1985	120,190.99	9,673.65	8.05%	96.12	0.08%	9,577.53	7.97%
1984 - 1986	112,373.04	10,785.81	9.60%	96.12	0.09%	10,689.69	9.51%
1985 - 1987	86,733.46	9,558.39	11.02%	932.23	1.07%	8,626.16	9.95%
1986 - 1988	92,604.83	14,299.27	15.44%	1,504.42	1.62%	12,794.85	13.82%
1987 - 1989	103,379.16	11,652.94	11.27%	1,504.42	1.46%	10,148.52	9.82%
1988 - 1990	120,344.86	10,154.31	8.44%	668.31	0.56%	9,486.00	7.88%
1989 - 1991	134,223.85	9,957.05	7.42%	173.62	0.13%	9,783.43	7.29%
1990 - 1992	130,937.04	13,390.63	10.23%	173.62	0.13%	13,217.01	10.09%
1991 - 1993	120,379.42	14,731.15	12.24%	173.62	0.14%	14,557.53	12.09%
1992 - 1994	104,947.39	13,872.61	13.22%	0.00	0.00%	13,872.61	13.22%
1993 - 1995	109,373.22	7,413.02	6.78%	0.00	0.00%	7,413.02	6.78%
1994 - 1996	129,688.98	14,542.23	11.21%	737.81	0.57%	13,804.42	10.64%
1995 - 1997	110,247.76	18,690.68	16.95%	737.81	0.67%	17,952.87	16.28%

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	102,102.16	19,968.36	19.56%	737.81	0.72%	19,230.55	18.83%
1997 - 1999	47,542.12	12,074.41	25.40%	0.00	0.00%	12,074.41	25.40%
1998 - 2000	34,509.18	9,527.09	27.61%	72.07	0.21%	9,455.02	27.40%
1999 - 2001	26,406.19	9,745.19	36.90%	72.07	0.27%	9,673.12	36.63%
2000 - 2002	30,773.90	7,657.80	24.88%	72.07	0.23%	7,585.73	24.65%
2001 - 2003	39,057.20	5,130.83	13.14%	0.00	0.00%	5,130.83	13.14%
2002 - 2004	20,203.05	5,543.42	27.44%	0.00	0.00%	5,543.42	27.44%
2003 - 2005	14,966.98	9,304.97	62.17%	0.00	0.00%	9,304.97	62.17%
2004 - 2006	5,149.22	14,900.67	289.38%	0.00	0.00%	14,900.67	289.38%
2005 - 2007	2,130.63	18,457.85	866.31%	0.00	0.00%	18,457.85	866.31%
2006 - 2008	9,387.37	25,557.87	272.26%	745.37	7.94%	24,812.50	264.32%

Montana-Dakota Utilities Company
Gas Division
383.00 HOUSE REGULATORS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 2008	901,773.75	183,978.42	20.40	3,702.72	0.41	180,275.70	19.99

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	40.0
Average Retirement Age (Yrs)	18.5
Years To ASL	21.5
Inflation Factor At 2.75% to ASL	1.79

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	284.77%
1994-2008	**15 - Year Trend**	358.17%
1999-2008	**10 - Year Trend**	480.59%
2004-2008	**5 - Year Trend**	691.64%

Forcasted

Gross Salvage 691.64%
(Five Year Trend)

Cost Of Removal 0.73%

Net Salvage 690.91%

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	613.45	-2,577.52	-420.17%	129.34	21.08%	(2,706.86)	-441.25%
1969	4,471.70	-26.46	-0.59%	179.48	4.01%	(205.94)	-4.61%
1970	840.44	-274.04	-32.61%	0.00	0.00%	(274.04)	-32.61%
1971	1,921.57	-1,005.39	-52.32%	59.46	3.09%	(1,064.85)	-55.42%
1972	2,369.19	-236.27	-9.97%	156.56	6.61%	(392.83)	-16.58%
1973	337.68	-693.23	-205.29%	12.88	3.81%	(706.11)	-209.11%
1974	1,632.24	0.00	0.00%	7.72	0.47%	(7.72)	-0.47%
1975	809.14	-3,193.08	-394.63%	31.14	3.85%	(3,224.22)	-398.47%
1976	2,695.45	-460.91	-17.10%	314.64	11.67%	(775.55)	-28.77%
1977	628.56	-13.63	-2.17%	90.60	14.41%	(104.23)	-16.58%
1978	246.13	-225.71	-91.70%	46.40	18.85%	(272.11)	-110.56%
1979	848.27	-1,982.76	-233.74%	358.00	42.20%	(2,340.76)	-275.95%
1980	2,986.62	-1,027.50	-34.40%	391.29	13.10%	(1,418.79)	-47.50%
1981	4,852.47	-1,293.36	-26.65%	318.84	6.57%	(1,612.20)	-33.22%
1982	2,491.09	-1,109.18	-44.53%	487.82	19.58%	(1,597.00)	-64.11%
1983	937.60	-897.15	-95.69%	226.31	24.14%	(1,123.46)	-119.82%
1984	1,819.48	0.00	0.00%	20.05	1.10%	(20.05)	-1.10%
1985	242.94	-227.14	-93.50%	384.69	158.35%	(611.83)	-251.84%
1986	573.60	-2,075.47	-361.83%	0.00	0.00%	(2,075.47)	-361.83%
1987	5,110.78	-1,187.43	-23.23%	653.90	12.79%	(1,841.33)	-36.03%
1988	626.39	0.00	0.00%	118.00	18.84%	(118.00)	-18.84%
1989	352.03	-1,503.95	-427.22%	0.00	0.00%	(1,503.95)	-427.22%
1990	3,978.13	-3,065.40	-77.06%	48.64	1.22%	(3,114.04)	-78.28%
1991	20,057.46	0.00	0.00%	1,824.81	9.10%	(1,824.81)	-9.10%
1992	5,915.92	-700.00	-11.83%	0.00	0.00%	(700.00)	-11.83%
1993	0.00	-5,952.35	0.00%	0.00	0.00%	(5,952.35)	0.00%
1994	9,478.47	0.00	0.00%	612.40	6.46%	(612.40)	-6.46%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	521.01	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	1,778.43	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	7,894.41	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	8,225.85	0.00	0.00%	1,350.95	16.42%	(1,350.95)	-16.42%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	375.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	561.38	0.00	0.00%	199.68	35.57%	(199.68)	-35.57%
2003	6,163.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	464.54	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	2,526.60	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1968 - 1970	5,925.59	-2,878.02	-48.57%	308.82	5.21%	(3,186.84)	-53.78%
1969 - 1971	7,233.71	-1,305.89	-18.05%	238.94	3.30%	(1,544.83)	-21.36%
1970 - 1972	5,131.20	-1,515.70	-29.54%	216.02	4.21%	(1,731.72)	-33.75%
1971 - 1973	4,628.44	-1,934.89	-41.80%	228.90	4.95%	(2,163.79)	-46.75%
1972 - 1974	4,339.11	-929.50	-21.42%	177.16	4.08%	(1,106.66)	-25.50%
1973 - 1975	2,779.06	-3,886.31	-139.84%	51.74	1.86%	(3,938.05)	-141.70%
1974 - 1976	5,136.83	-3,653.99	-71.13%	353.50	6.88%	(4,007.49)	-78.01%
1975 - 1977	4,133.15	-3,667.62	-88.74%	436.38	10.56%	(4,104.00)	-99.29%
1976 - 1978	3,570.14	-700.25	-19.61%	451.64	12.65%	(1,151.89)	-32.26%
1977 - 1979	1,722.96	-2,222.10	-128.97%	495.00	28.73%	(2,717.10)	-157.70%
1978 - 1980	4,081.02	-3,235.97	-79.29%	795.69	19.50%	(4,031.66)	-98.79%
1979 - 1981	8,687.36	-4,303.62	-49.54%	1,068.13	12.30%	(5,371.75)	-61.83%
1980 - 1982	10,330.18	-3,430.04	-33.20%	1,197.95	11.60%	(4,627.99)	-44.80%
1981 - 1983	8,281.16	-3,299.69	-39.85%	1,032.97	12.47%	(4,332.66)	-52.32%
1982 - 1984	5,248.17	-2,006.33	-38.23%	734.18	13.99%	(2,740.51)	-52.22%
1983 - 1985	3,000.02	-1,124.29	-37.48%	631.05	21.03%	(1,755.34)	-58.51%
1984 - 1986	2,636.02	-2,302.61	-87.35%	404.74	15.35%	(2,707.35)	-102.71%
1985 - 1987	5,927.32	-3,490.04	-58.88%	1,038.59	17.52%	(4,528.63)	-76.40%
1986 - 1988	6,310.77	-3,262.90	-51.70%	771.90	12.23%	(4,034.80)	-63.94%
1987 - 1989	6,089.20	-2,691.38	-44.20%	771.90	12.68%	(3,463.28)	-56.88%
1988 - 1990	4,956.55	-4,569.35	-92.19%	166.64	3.36%	(4,735.99)	-95.55%
1989 - 1991	24,387.62	-4,569.35	-18.74%	1,873.45	7.68%	(6,442.80)	-26.42%
1990 - 1992	29,951.51	-3,765.40	-12.57%	1,873.45	6.25%	(5,638.85)	-18.83%
1991 - 1993	25,973.38	-6,652.35	-25.61%	1,824.81	7.03%	(8,477.16)	-32.64%
1992 - 1994	15,394.39	-6,652.35	-43.21%	612.40	3.98%	(7,264.75)	-47.19%
1993 - 1995	9,478.47	-5,952.35	-62.80%	612.40	6.46%	(6,564.75)	-69.26%
1994 - 1996	9,999.48	0.00	0.00%	612.40	6.12%	(612.40)	-6.12%
1995 - 1997	2,299.44	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	10,193.85	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	17,898.69	0.00	0.00%	1,350.95	7.55%	(1,350.95)	-7.55%
1998 - 2000	16,120.26	0.00	0.00%	1,350.95	8.38%	(1,350.95)	-8.38%
1999 - 2001	8,600.85	0.00	0.00%	1,350.95	15.71%	(1,350.95)	-15.71%
2000 - 2002	936.38	0.00	0.00%	199.68	21.32%	(199.68)	-21.32%
2001 - 2003	7,099.93	0.00	0.00%	199.68	2.81%	(199.68)	-2.81%
2002 - 2004	7,189.47	0.00	0.00%	199.68	2.78%	(199.68)	-2.78%
2003 - 2005	9,154.69	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	2,991.14	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005 - 2007	2,526.60	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
385.00 IND. MEAS. & REG. STA. EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 2008	105,347.57	-29,727.93	-28.22	8,023.60	7.62	(37,751.53)	-35.84

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	35.0
Average Retirement Age (Yrs)	14.9
Years To ASL	20.1
Inflation Factor At 2.75% to ASL	1.72

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	16.31%
1994-2008	**15 - Year Trend**	12.34%
1999-2008	**10 - Year Trend**	0.00%
2004-2008	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	13.14%
Net Salvage	-13.14%

Montana-Dakota Utilities Company
Gas Division
386.20 CNG REFUELING STATIONS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2006 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
2006	170,931.14	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
386.20 CNG REFUELING STATIONS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2006 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
2006 - 2008	170,931.14	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	170,931.14	0.00	0.00	0.00	0.00	0.00	0.00

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	15.0
Average Retirement Age (Yrs)	14.5
Years To ASL	0.5
Inflation Factor At 2.75% to ASL	1.01

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	0.00%
1994-2008	**15 - Year Trend**	0.00%
1999-2008	**10 - Year Trend**	0.00%
2004-2008	**5 - Year Trend**	0.00%

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.00%
Net Salvage	0.00%

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	5,811.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	11,739.35	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	1,543.21	-459.00	-29.74%	112.23	7.27%	(571.23)	-37.02%
1971	10,490.96	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	19,729.18	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	18,059.89	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	9,563.58	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	8,497.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	11,454.91	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	17,086.04	0.00	0.00%	13.44	0.08%	(13.44)	-0.08%
1978	15,552.61	0.00	0.00%	15.95	0.10%	(15.95)	-0.10%
1979	8,364.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	14,978.92	583.96	3.90%	0.00	0.00%	583.96	3.90%
1981	15,697.01	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	12,740.49	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	15,906.12	0.00	0.00%	499.89	3.14%	(499.89)	-3.14%
1984	20,715.99	0.00	0.00%	615.83	2.97%	(615.83)	-2.97%
1985	4,817.26	-99.41	-2.06%	2,014.67	41.82%	(2,114.08)	-43.89%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	19,054.14	186.00	0.98%	669.05	3.51%	(483.05)	-2.54%
1988	31,269.89	200.00	0.64%	407.10	1.30%	(207.10)	-0.66%
1989	17,992.33	727.66	4.04%	405.51	2.25%	322.15	1.79%
1990	1,264.75	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	23,983.88	1,054.24	4.40%	517.44	2.16%	536.80	2.24%
1992	31,528.72	-220.00	-0.70%	4,193.91	13.30%	(4,413.91)	-14.00%
1993	57,065.06	477.66	0.84%	876.70	1.54%	(399.04)	-0.70%
1994	33,869.58	2,255.32	6.66%	160.59	0.47%	2,094.73	6.18%
1995	7,284.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	24,784.53	477.66	1.93%	295.65	1.19%	182.01	0.73%
1997	18,582.17	478.00	2.57%	27.98	0.15%	450.02	2.42%
1998	15,042.49	0.00	0.00%	44.71	0.30%	(44.71)	-0.30%
1999	18,373.16	0.00	0.00%	133.29	0.73%	(133.29)	-0.73%
2000	18,008.38	0.00	0.00%	104.13	0.58%	(104.13)	-0.58%
2001	20,910.61	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	6,232.69	0.00	0.00%	80.32	1.29%	(80.32)	-1.29%
2003	5,053.34	743.61	14.72%	0.00	0.00%	743.61	14.72%
2004	11,487.44	0.00	0.00%	16.10	0.14%	(16.10)	-0.14%
2005	17,644.73	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	4,083.92	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	12,684.22	0.00	0.00%	317.00	2.50%	(317.00)	-2.50%
2008	3,961.70	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	19,094.31	-459.00	-2.40%	112.23	0.59%	(571.23)	-2.99%
1969 - 1971	23,773.52	-459.00	-1.93%	112.23	0.47%	(571.23)	-2.40%
1970 - 1972	31,763.35	-459.00	-1.45%	112.23	0.35%	(571.23)	-1.80%
1971 - 1973	48,280.03	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972 - 1974	47,352.65	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973 - 1975	36,120.66	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974 - 1976	29,515.68	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975 - 1977	37,038.14	0.00	0.00%	13.44	0.04%	(13.44)	-0.04%
1976 - 1978	44,093.56	0.00	0.00%	29.39	0.07%	(29.39)	-0.07%
1977 - 1979	41,003.53	0.00	0.00%	29.39	0.07%	(29.39)	-0.07%
1978 - 1980	38,896.41	583.96	1.50%	15.95	0.04%	568.01	1.46%
1979 - 1981	39,040.81	583.96	1.50%	0.00	0.00%	583.96	1.50%
1980 - 1982	43,416.42	583.96	1.35%	0.00	0.00%	583.96	1.35%
1981 - 1983	44,343.62	0.00	0.00%	499.89	1.13%	(499.89)	-1.13%
1982 - 1984	49,362.60	0.00	0.00%	1,115.72	2.26%	(1,115.72)	-2.26%
1983 - 1985	41,439.37	-99.41	-0.24%	3,130.39	7.55%	(3,229.80)	-7.79%
1984 - 1986	25,533.25	-99.41	-0.39%	2,630.50	10.30%	(2,729.91)	-10.69%
1985 - 1987	23,871.40	86.59	0.36%	2,683.72	11.24%	(2,597.13)	-10.88%
1986 - 1988	50,324.03	386.00	0.77%	1,076.15	2.14%	(690.15)	-1.37%
1987 - 1989	68,316.36	1,113.66	1.63%	1,481.66	2.17%	(368.00)	-0.54%
1988 - 1990	50,526.97	927.66	1.84%	812.61	1.61%	115.05	0.23%
1989 - 1991	43,240.96	1,781.90	4.12%	922.95	2.13%	858.95	1.99%
1990 - 1992	56,777.35	834.24	1.47%	4,711.35	8.30%	(3,877.11)	-6.83%
1991 - 1993	112,577.66	1,311.90	1.17%	5,588.05	4.96%	(4,276.15)	-3.80%
1992 - 1994	122,463.36	2,512.98	2.05%	5,231.20	4.27%	(2,718.22)	-2.22%
1993 - 1995	98,218.64	2,732.98	2.78%	1,037.29	1.06%	1,695.69	1.73%
1994 - 1996	65,938.11	2,732.98	4.14%	456.24	0.69%	2,276.74	3.45%
1995 - 1997	50,650.70	955.66	1.89%	323.63	0.64%	632.03	1.25%

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1996 - 1998	58,409.19	955.66	1.64%	368.34	0.63%	587.32	1.01%
1997 - 1999	51,997.82	478.00	0.92%	205.98	0.40%	272.02	0.52%
1998 - 2000	51,424.03	0.00	0.00%	282.13	0.55%	(282.13)	-0.55%
1999 - 2001	57,292.15	0.00	0.00%	237.42	0.41%	(237.42)	-0.41%
2000 - 2002	45,151.68	0.00	0.00%	184.45	0.41%	(184.45)	-0.41%
2001 - 2003	32,196.64	743.61	2.31%	80.32	0.25%	663.29	2.06%
2002 - 2004	22,773.47	743.61	3.27%	96.42	0.42%	647.19	2.84%
2003 - 2005	34,185.51	743.61	2.18%	16.10	0.05%	727.51	2.13%
2004 - 2006	33,216.09	0.00	0.00%	16.10	0.05%	(16.10)	-0.05%
2005 - 2007	34,412.87	0.00	0.00%	317.00	0.92%	(317.00)	-0.92%
2006 - 2008	20,729.84	0.00	0.00%	317.00	1.53%	(317.00)	-1.53%

Montana-Dakota Utilities Company
Gas Division
387.10 CATHODIC PROTECTION EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 2008	622,911.07	6,405.70	1.03	11,521.49	1.85	(5,115.79)	-0.82

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	20.0
Average Retirement Age (Yrs)	14.5
Years To ASL	5.5
Inflation Factor At 2.75% to ASL	1.16

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	0.50%
1994-2008	**15 - Year Trend**	0.18%
1999-2008	**10 - Year Trend**	0.84%
2004-2008	**5 - Year Trend**	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	2.15%
Net Salvage	-2.15%

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1977 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1977	415.20	-1.98	-0.48%	88.61	21.34%	(90.59)	-21.82%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	606.13	-149.36	-24.64%	0.00	0.00%	(149.36)	-24.64%
1988	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1989	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1990	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	1,158.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	3,481.02	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	962.88	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	1,945.37	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1977 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
2005	16,213.95	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1977 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1977 - 1979	415.20	-1.98	-0.48%	88.61	21.34%	(90.59)	-21.82%
1978 - 1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979 - 1981	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	1,924.52	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982 - 1984	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983 - 1985	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1984 - 1986	1,155.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1985 - 1987	606.13	-149.36	-24.64%	0.00	0.00%	(149.36)	-24.64%
1986 - 1988	606.13	-149.36	-24.64%	0.00	0.00%	(149.36)	-24.64%
1987 - 1989	3,275.67	171.64	5.24%	0.00	0.00%	171.64	5.24%
1988 - 1990	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1989 - 1991	2,669.54	321.00	12.02%	0.00	0.00%	321.00	12.02%
1990 - 1992	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991 - 1993	242.94	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992 - 1994	1,401.30	0.00	0.00%	0.00	0.00%	0.00	0.00%
1993 - 1995	1,158.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994 - 1996	4,639.38	0.00	0.00%	0.00	0.00%	0.00	0.00%
1995 - 1997	4,443.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996 - 1998	4,443.90	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997 - 1999	3,622.44	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999 - 2001	2,659.56	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2003	1,945.37	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	1,945.37	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	18,159.32	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004 - 2006	16,213.95	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
387.20 OTHER DISTRIBUTION EQUIP.

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1977 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
2005 - 2007	16,213.95	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977 - 2008	33,435.37	169.66	0.51	88.61	0.27	81.05	0.24

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	25.0
Average Retirement Age (Yrs)	18.6
Years To ASL	6.4
Inflation Factor At 2.75% to ASL	1.19

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	0.00% *
1994-2008	**15 - Year Trend**	0.00%
1999-2008	**10 - Year Trend**	0.00%
2004-2008	**5 - Year Trend**	0.00%

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00%
Cost Of Removal	0.32%
Net Salvage	-0.32%

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1968	4,011.48	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1970	1,939.40	330.00	17.02%	0.19	0.01%	329.81	17.01%
1971	220.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	5,237.65	0.00	0.00%	98.15	1.87%	(98.15)	-1.87%
1974	3,163.71	0.00	0.00%	455.62	14.40%	(455.62)	-14.40%
1975	1,500.00	0.00	0.00%	62.31	4.15%	(62.31)	-4.15%
1976	150.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	4,154.28	0.00	0.00%	152.88	3.68%	(152.88)	-3.68%
1981	5,991.28	0.00	0.00%	28.54	0.48%	(28.54)	-0.48%
1982	2,768.63	197.20	7.12%	56.80	2.05%	140.40	5.07%
1983	0.00	250.00	0.00%	0.00	0.00%	250.00	0.00%
1984	52,319.71	0.00	0.00%	1,142.50	2.18%	(1,142.50)	-2.18%
1985	0.00	0.00	0.00%	542.71	0.00%	(542.71)	0.00%
1986	4,959.76	1,000.00	20.16%	327.26	6.60%	672.74	13.56%
1987	100,209.57	0.00	0.00%	85.89	0.09%	(85.89)	-0.09%
1988	107,578.45	40.00	0.04%	2,115.59	1.97%	(2,075.59)	-1.93%
1989	10,343.74	0.00	0.00%	629.80	6.09%	(629.80)	-6.09%
1990	250.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1991	531.17	0.00	0.00%	107.21	20.18%	(107.21)	-20.18%
1992	4,817.26	-99.41	-2.06%	2,650.10	55.01%	(2,749.51)	-57.08%
1993	5,081.86	0.00	0.00%	1,859.58	36.59%	(1,859.58)	-36.59%
1994	1,618.38	0.00	0.00%	15.82	0.98%	(15.82)	-0.98%
1995	109,499.69	154,090.00	140.72%	934.46	0.85%	153,155.54	139.87%

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage* *Amount*	*%*	*Cost of Removal* *Amount*	*%*	*Net Salvage* *Amount*	*%*
Annual Activity							
1996	138,637.71	196,098.21	141.45%	1,217.79	0.88%	194,880.42	140.57%
1997	9,710.60	0.00	0.00%	577.91	5.95%	(577.91)	-5.95%
1998	6,373.20	0.00	0.00%	1,006.53	15.79%	(1,006.53)	-15.79%
1999	2,036.72	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	469,368.95	325,000.00	69.24%	23,530.00	5.01%	301,470.00	64.23%
2003	9,314.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	3,228.00	0.00	0.00%	125.00	3.87%	(125.00)	-3.87%
2005	6,951.13	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	11,119.09	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	17,471.72	40,375.00	231.09%	2,001.88	11.46%	38,373.12	219.63%
2008	10,887.80	7,171.21	65.86%	0.00	0.00%	7,171.21	65.86%

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	5,950.88	330.00	5.55%	0.19	0.00%	329.81	5.54%
1969 - 1971	2,159.40	330.00	15.28%	0.19	0.01%	329.81	15.27%
1970 - 1972	2,159.40	330.00	15.28%	0.19	0.01%	329.81	15.27%
1971 - 1973	5,457.65	0.00	0.00%	98.15	1.80%	(98.15)	-1.80%
1972 - 1974	8,401.36	0.00	0.00%	553.77	6.59%	(553.77)	-6.59%
1973 - 1975	9,901.36	0.00	0.00%	616.08	6.22%	(616.08)	-6.22%
1974 - 1976	4,813.71	0.00	0.00%	517.93	10.76%	(517.93)	-10.76%
1975 - 1977	1,650.00	0.00	0.00%	62.31	3.78%	(62.31)	-3.78%
1976 - 1978	150.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1977 - 1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978 - 1980	4,154.28	0.00	0.00%	152.88	3.68%	(152.88)	-3.68%
1979 - 1981	10,145.56	0.00	0.00%	181.42	1.79%	(181.42)	-1.79%
1980 - 1982	12,914.19	197.20	1.53%	238.22	1.84%	(41.02)	-0.32%
1981 - 1983	8,759.91	447.20	5.11%	85.34	0.97%	361.86	4.13%
1982 - 1984	55,088.34	447.20	0.81%	1,199.30	2.18%	(752.10)	-1.37%
1983 - 1985	52,319.71	250.00	0.48%	1,685.21	3.22%	(1,435.21)	-2.74%
1984 - 1986	57,279.47	1,000.00	1.75%	2,012.47	3.51%	(1,012.47)	-1.77%
1985 - 1987	105,169.33	1,000.00	0.95%	955.86	0.91%	44.14	0.04%
1986 - 1988	212,747.78	1,040.00	0.49%	2,528.74	1.19%	(1,488.74)	-0.70%
1987 - 1989	218,131.76	40.00	0.02%	2,831.28	1.30%	(2,791.28)	-1.28%
1988 - 1990	118,172.19	40.00	0.03%	2,745.39	2.32%	(2,705.39)	-2.29%
1989 - 1991	11,124.91	0.00	0.00%	737.01	6.62%	(737.01)	-6.62%
1990 - 1992	5,598.43	-99.41	-1.78%	2,757.31	49.25%	(2,856.72)	-51.03%
1991 - 1993	10,430.29	-99.41	-0.95%	4,616.89	44.26%	(4,716.30)	-45.22%
1992 - 1994	11,517.50	-99.41	-0.86%	4,525.50	39.29%	(4,624.91)	-40.16%
1993 - 1995	116,199.93	154,090.00	132.61%	2,809.86	2.42%	151,280.14	130.19%
1994 - 1996	249,755.78	350,188.21	140.21%	2,168.07	0.87%	348,020.14	139.34%
1995 - 1997	257,848.00	350,188.21	135.81%	2,730.16	1.06%	347,458.05	134.75%

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	154,721.51	196,098.21	126.74%	2,802.23	1.81%	193,295.98	124.93%
1997 - 1999	18,120.52	0.00	0.00%	1,584.44	8.74%	(1,584.44)	-8.74%
1998 - 2000	8,409.92	0.00	0.00%	1,006.53	11.97%	(1,006.53)	-11.97%
1999 - 2001	2,036.72	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000 - 2002	469,368.95	325,000.00	69.24%	23,530.00	5.01%	301,470.00	64.23%
2001 - 2003	478,682.95	325,000.00	67.89%	23,530.00	4.92%	301,470.00	62.98%
2002 - 2004	481,910.95	325,000.00	67.44%	23,655.00	4.91%	301,345.00	62.53%
2003 - 2005	19,493.13	0.00	0.00%	125.00	0.64%	(125.00)	-0.64%
2004 - 2006	21,298.22	0.00	0.00%	125.00	0.59%	(125.00)	-0.59%
2005 - 2007	35,541.94	40,375.00	113.60%	2,001.88	5.63%	38,373.12	107.97%
2006 - 2008	39,478.61	47,546.21	120.44%	2,001.88	5.07%	45,544.33	115.36%

Montana-Dakota Utilities Company
Gas Division
390.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1968 - 2008	1,111,444.94	724,452.21	65.18	39,724.52	3.57	684,727.69	61.61

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	31.0
Average Retirement Age (Yrs)	13.6
Years To ASL	17.4
Inflation Factor At 2.75% to ASL	1.61

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	79.58%
1994-2008	**15 - Year Trend**	51.10%
1999-2008	**10 - Year Trend**	99.56%
2004-2008	**5 - Year Trend**	126.17%

Forcasted

Gross Salvage 126.17%
(Five Year Trend)

Cost Of Removal 5.73%

Net Salvage 120.44%

Montana-Dakota Utilities Company
Gas Division
392.10 TRANSPORTATION EQUIPMENT - TRAILERS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1997	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2000	826.93	150.00	18.14%	0.00	0.00%	150.00	18.14%
2001	14,059.66	1,701.00	12.10%	0.00	0.00%	1,701.00	12.10%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	310.22	50.00	16.12%	0.00	0.00%	50.00	16.12%
2005	771.47	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	7,093.48	2,500.00	35.24%	0.00	0.00%	2,500.00	35.24%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Gas Division
392.10 TRANSPORTATION EQUIPMENT - TRAILERS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	0.00	316.00	0.00%	47.25	0.00%	268.75	0.00%
1997 - 1999	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1998 - 2000	826.93	150.00	18.14%	0.00	0.00%	150.00	18.14%
1999 - 2001	14,886.59	1,851.00	12.43%	0.00	0.00%	1,851.00	12.43%
2000 - 2002	14,886.59	1,851.00	12.43%	0.00	0.00%	1,851.00	12.43%
2001 - 2003	14,059.66	1,701.00	12.10%	0.00	0.00%	1,701.00	12.10%
2002 - 2004	310.22	50.00	16.12%	0.00	0.00%	50.00	16.12%
2003 - 2005	1,081.69	50.00	4.62%	0.00	0.00%	50.00	4.62%
2004 - 2006	1,081.69	50.00	4.62%	0.00	0.00%	50.00	4.62%
2005 - 2007	7,864.95	2,500.00	31.79%	0.00	0.00%	2,500.00	31.79%
2006 - 2008	7,093.48	2,500.00	35.24%	0.00	0.00%	2,500.00	35.24%

Montana-Dakota Utilities Company
Gas Division
392.10 TRANSPORTATION EQUIPMENT - TRAILERS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1996 - 2008	23,061.76	4,717.00	20.45	47.25	0.20	4,669.75	20.25

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	8.0
Average Retirement Age (Yrs)	4.5
Years To ASL	3.5
Inflation Factor At 2.75% to ASL	1.10

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	13.46%
1994-2008	**15 - Year Trend**	13.46%
1999-2008	**10 - Year Trend**	26.56%
2004-2008	**5 - Year Trend**	38.10%

Forcasted

Gross Salvage (Five Year Trend)	38.10%
Cost Of Removal	0.22%
Net Salvage	37.88%

Montana-Dakota Utilities Company
Gas Division
392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1995 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1995	294,595.14	31,225.71	10.60%	332.01	0.11%	30,893.70	10.49%
1996	386,586.06	94,300.22	24.39%	3,363.10	0.87%	90,937.12	23.52%
1997	202,459.15	35,010.10	17.29%	409.73	0.20%	34,600.37	17.09%
1998	436,818.58	106,096.36	24.29%	1,086.25	0.25%	105,010.11	24.04%
1999	349,200.70	56,912.97	16.30%	1,161.44	0.33%	55,751.53	15.97%
2000	706,714.53	124,990.96	17.69%	794.80	0.11%	124,196.16	17.57%
2001	481,092.35	84,394.75	17.54%	1,370.15	0.28%	83,024.60	17.26%
2002	385,989.97	70,616.60	18.29%	788.63	0.20%	69,827.97	18.09%
2003	551,427.51	94,187.99	17.08%	371.20	0.07%	93,816.79	17.01%
2004	703,342.91	126,344.82	17.96%	157.88	0.02%	126,186.94	17.94%
2005	932,459.98	189,285.13	20.30%	0.00	0.00%	189,285.13	20.30%
2006	634,320.92	133,631.75	21.07%	0.00	0.00%	133,631.75	21.07%
2007	761,027.65	158,848.37	20.87%	0.00	0.00%	158,848.37	20.87%
2008	856,416.32	182,815.94	21.35%	0.00	0.00%	182,815.94	21.35%

Montana-Dakota Utilities Company
Gas Division
392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1995 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1995 - 1997	883,640.35	160,536.03	18.17%	4,104.84	0.46%	156,431.19	17.70%
1996 - 1998	1,025,863.79	235,406.68	22.95%	4,859.08	0.47%	230,547.60	22.47%
1997 - 1999	988,478.43	198,019.43	20.03%	2,657.42	0.27%	195,362.01	19.76%
1998 - 2000	1,492,733.81	288,000.29	19.29%	3,042.49	0.20%	284,957.80	19.09%
1999 - 2001	1,537,007.58	266,298.68	17.33%	3,326.39	0.22%	262,972.29	17.11%
2000 - 2002	1,573,796.85	280,002.31	17.79%	2,953.58	0.19%	277,048.73	17.60%
2001 - 2003	1,418,509.83	249,199.34	17.57%	2,529.98	0.18%	246,669.36	17.39%
2002 - 2004	1,640,760.39	291,149.41	17.74%	1,317.71	0.08%	289,831.70	17.66%
2003 - 2005	2,187,230.40	409,817.94	18.74%	529.08	0.02%	409,288.86	18.71%
2004 - 2006	2,270,123.81	449,261.70	19.79%	157.88	0.01%	449,103.82	19.78%
2005 - 2007	2,327,808.55	481,765.25	20.70%	0.00	0.00%	481,765.25	20.70%
2006 - 2008	2,251,764.89	475,296.06	21.11%	0.00	0.00%	475,296.06	21.11%

Montana-Dakota Utilities Company
Gas Division
392.20 TRANSPORTATION EQUIPMENT - CARS & TRUCKS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1995 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1995 - 2008	7,682,451.77	1,488,661.67	19.38	9,835.19	0.13	1,478,826.48	19.25

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	7.0
Average Retirement Age (Yrs)	4.1
Years To ASL	2.9
Inflation Factor At 2.75% to ASL	1.08

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	19.33%
1994-2008	**15 - Year Trend**	19.33%
1999-2008	**10 - Year Trend**	20.17%
2004-2008	**5 - Year Trend**	22.22%

Forcasted

Gross Salvage (Five Year Trend)	22.22%
Cost Of Removal	0.14%
Net Salvage	22.08%

Montana-Dakota Utilities Company
Gas Division
396.10 WORK EQUIPMENT TRAILERS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1996	0.00	101.99	0.00%	0.00	0.00%	101.99	0.00%
1997	15,108.23	8,030.00	53.15%	0.00	0.00%	8,030.00	53.15%
1998	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1999	16,315.67	7,500.00	45.97%	0.00	0.00%	7,500.00	45.97%
2000	1,334.52	450.00	33.72%	0.00	0.00%	450.00	33.72%
2001	6,275.36	2,059.88	32.82%	149.20	2.38%	1,910.68	30.45%
2002	1,066.23	653.00	61.24%	0.00	0.00%	653.00	61.24%
2003	5,322.87	1,112.00	20.89%	0.00	0.00%	1,112.00	20.89%
2004	5,537.87	150.00	2.71%	0.00	0.00%	150.00	2.71%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	2,816.61	1,189.00	42.21%	0.00	0.00%	1,189.00	42.21%
2008	9,946.84	1,207.21	12.14%	0.00	0.00%	1,207.21	12.14%

Montana-Dakota Utilities Company
Gas Division
396.10 WORK EQUIPMENT TRAILERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1996 - 1998	15,108.23	8,131.99	53.82%	0.00	0.00%	8,131.99	53.82%
1997 - 1999	31,423.90	15,530.00	49.42%	0.00	0.00%	15,530.00	49.42%
1998 - 2000	17,650.19	7,950.00	45.04%	0.00	0.00%	7,950.00	45.04%
1999 - 2001	23,925.55	10,009.88	41.84%	149.20	0.62%	9,860.68	41.21%
2000 - 2002	8,676.11	3,162.88	36.46%	149.20	1.72%	3,013.68	34.74%
2001 - 2003	12,664.46	3,824.88	30.20%	149.20	1.18%	3,675.68	29.02%
2002 - 2004	11,926.97	1,915.00	16.06%	0.00	0.00%	1,915.00	16.06%
2003 - 2005	10,860.74	1,262.00	11.62%	0.00	0.00%	1,262.00	11.62%
2004 - 2006	5,537.87	150.00	2.71%	0.00	0.00%	150.00	2.71%
2005 - 2007	2,816.61	1,189.00	42.21%	0.00	0.00%	1,189.00	42.21%
2006 - 2008	12,763.45	2,396.21	18.77%	0.00	0.00%	2,396.21	18.77%

Montana-Dakota Utilities Company
Gas Division
396.10 WORK EQUIPMENT TRAILERS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1996 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1996 - 2008	63,724.20	22,453.08	35.23	149.20	0.23	22,303.88	35.00

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	10.0
Average Retirement Age (Yrs)	7.4
Years To ASL	2.6
Inflation Factor At 2.75% to ASL	1.07

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	31.73%
1994-2008	**15 - Year Trend**	31.73%
1999-2008	**10 - Year Trend**	10.10%
2004-2008	**5 - Year Trend**	29.08%

Forcasted

Gross Salvage (Five Year Trend)	29.08%
Cost Of Removal	0.25%
Net Salvage	28.84%

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	7,624.55	0.00	0.00%	0.00	0.00%	0.00	0.00%
1969	18,036.43	4,660.75	25.84%	0.00	0.00%	4,660.75	25.84%
1970	85,745.78	20,081.65	23.42%	2.56	0.00%	20,079.09	23.42%
1971	32,522.96	16,959.50	52.15%	0.00	0.00%	16,959.50	52.15%
1972	68,343.72	34,167.38	49.99%	0.00	0.00%	34,167.38	49.99%
1973	19,453.17	1,321.00	6.79%	0.00	0.00%	1,321.00	6.79%
1974	70,200.13	36,952.50	52.64%	0.00	0.00%	36,952.50	52.64%
1975	48,205.77	23,256.00	48.24%	0.00	0.00%	23,256.00	48.24%
1976	36,542.30	16,760.00	45.86%	21.00	0.06%	16,739.00	45.81%
1977	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	21,151.37	11,502.00	54.38%	0.00	0.00%	11,502.00	54.38%
1979	57,535.68	20,150.00	35.02%	0.00	0.00%	20,150.00	35.02%
1980	33,055.15	16,318.30	49.37%	0.00	0.00%	16,318.30	49.37%
1981	187,078.07	133,470.40	71.34%	0.00	0.00%	133,470.40	71.34%
1982	82,780.89	38,429.13	46.42%	0.00	0.00%	38,429.13	46.42%
1983	93,278.27	89,865.50	96.34%	0.00	0.00%	89,865.50	96.34%
1984	65,798.80	36,885.83	56.06%	455.00	0.69%	36,430.83	55.37%
1985	-2,004.36	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	43,816.13	38,509.33	87.89%	0.00	0.00%	38,509.33	87.89%
1987	60,103.95	21,504.91	35.78%	211.74	0.35%	21,293.17	35.43%
1988	351,349.08	97,992.00	27.89%	698.08	0.20%	97,293.92	27.69%
1989	659,158.69	406,813.00	61.72%	232.86	0.04%	406,580.14	61.68%
1990	465,530.32	426,773.25	91.67%	191.71	0.04%	426,581.54	91.63%
1991	506,039.47	434,830.37	85.93%	27.47	0.01%	434,802.90	85.92%
1992	347,508.62	243,091.00	69.95%	131.21	0.04%	242,959.79	69.91%
1993	537,705.71	474,364.03	88.22%	0.00	0.00%	474,364.03	88.22%
1994	444,780.98	374,784.00	84.26%	29.22	0.01%	374,754.78	84.26%
1995	757,408.90	775,939.25	102.45%	10.00	0.00%	775,929.25	102.45%

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	847,905.78	632,158.36	74.56%	426.88	0.05%	631,731.48	74.50%
1997	1,288,447.77	1,287,216.85	99.90%	0.00	0.00%	1,287,216.85	99.90%
1998	635,435.44	520,006.27	81.83%	216.70	0.03%	519,789.57	81.80%
1999	1,644,011.39	1,296,953.70	78.89%	16,944.81	1.03%	1,280,008.89	77.86%
2000	578,648.60	446,315.01	77.13%	0.00	0.00%	446,315.01	77.13%
2001	1,350,062.37	1,118,466.41	82.85%	1,185.02	0.09%	1,117,281.39	82.76%
2002	294,171.49	203,871.50	69.30%	197.57	0.07%	203,673.93	69.24%
2003	1,487,414.47	954,759.67	64.19%	636.75	0.04%	954,122.92	64.15%
2004	1,294,071.91	1,087,417.11	84.03%	0.00	0.00%	1,087,417.11	84.03%
2005	1,589,284.84	1,384,642.73	87.12%	0.00	0.00%	1,384,642.73	87.12%
2006	1,686,987.64	1,363,963.11	80.85%	0.00	0.00%	1,363,963.11	80.85%
2007	1,959,431.97	1,749,870.13	89.30%	0.00	0.00%	1,749,870.13	89.30%
2008	2,038,426.92	1,894,911.85	92.96%	0.00	0.00%	1,894,911.85	92.96%

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	111,406.76	24,742.40	22.21%	2.56	0.00%	24,739.84	22.21%
1969 - 1971	136,305.17	41,701.90	30.59%	2.56	0.00%	41,699.34	30.59%
1970 - 1972	186,612.46	71,208.53	38.16%	2.56	0.00%	71,205.97	38.16%
1971 - 1973	120,319.85	52,447.88	43.59%	0.00	0.00%	52,447.88	43.59%
1972 - 1974	157,997.02	72,440.88	45.85%	0.00	0.00%	72,440.88	45.85%
1973 - 1975	137,859.07	61,529.50	44.63%	0.00	0.00%	61,529.50	44.63%
1974 - 1976	154,948.20	76,968.50	49.67%	21.00	0.01%	76,947.50	49.66%
1975 - 1977	84,748.07	40,016.00	47.22%	21.00	0.02%	39,995.00	47.19%
1976 - 1978	57,693.67	28,262.00	48.99%	21.00	0.04%	28,241.00	48.95%
1977 - 1979	78,687.05	31,652.00	40.23%	0.00	0.00%	31,652.00	40.23%
1978 - 1980	111,742.20	47,970.30	42.93%	0.00	0.00%	47,970.30	42.93%
1979 - 1981	277,668.90	169,938.70	61.20%	0.00	0.00%	169,938.70	61.20%
1980 - 1982	302,914.11	188,217.83	62.14%	0.00	0.00%	188,217.83	62.14%
1981 - 1983	363,137.23	261,765.03	72.08%	0.00	0.00%	261,765.03	72.08%
1982 - 1984	241,857.96	165,180.46	68.30%	455.00	0.19%	164,725.46	68.11%
1983 - 1985	157,072.71	126,751.33	80.70%	455.00	0.29%	126,296.33	80.41%
1984 - 1986	107,610.57	75,395.16	70.06%	455.00	0.42%	74,940.16	69.64%
1985 - 1987	101,915.72	60,014.24	58.89%	211.74	0.21%	59,802.50	58.68%
1986 - 1988	455,269.16	158,006.24	34.71%	909.82	0.20%	157,096.42	34.51%
1987 - 1989	1,070,611.72	526,309.91	49.16%	1,142.68	0.11%	525,167.23	49.05%
1988 - 1990	1,476,038.09	931,578.25	63.11%	1,122.65	0.08%	930,455.60	63.04%
1989 - 1991	1,630,728.48	1,268,416.62	77.78%	452.04	0.03%	1,267,964.58	77.75%
1990 - 1992	1,319,078.41	1,104,694.62	83.75%	350.39	0.03%	1,104,344.23	83.72%
1991 - 1993	1,391,253.80	1,152,285.40	82.82%	158.68	0.01%	1,152,126.72	82.81%
1992 - 1994	1,329,995.31	1,092,239.03	82.12%	160.43	0.01%	1,092,078.60	82.11%
1993 - 1995	1,739,895.59	1,625,087.28	93.40%	39.22	0.00%	1,625,048.06	93.40%
1994 - 1996	2,050,095.66	1,782,881.61	86.97%	466.10	0.02%	1,782,415.51	86.94%
1995 - 1997	2,893,762.45	2,695,314.46	93.14%	436.88	0.02%	2,694,877.58	93.13%

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1996 - 1998	2,771,788.99	2,439,381.48	88.01%	643.58	0.02%	2,438,737.90	87.98%
1997 - 1999	3,567,894.60	3,104,176.82	87.00%	17,161.51	0.48%	3,087,015.31	86.52%
1998 - 2000	2,858,095.43	2,263,274.98	79.19%	17,161.51	0.60%	2,246,113.47	78.59%
1999 - 2001	3,572,722.36	2,861,735.12	80.10%	18,129.83	0.51%	2,843,605.29	79.59%
2000 - 2002	2,222,882.46	1,768,652.92	79.57%	1,382.59	0.06%	1,767,270.33	79.50%
2001 - 2003	3,131,648.33	2,277,097.58	72.71%	2,019.34	0.06%	2,275,078.24	72.65%
2002 - 2004	3,075,657.87	2,246,048.28	73.03%	834.32	0.03%	2,245,213.96	73.00%
2003 - 2005	4,370,771.22	3,426,819.51	78.40%	636.75	0.01%	3,426,182.76	78.39%
2004 - 2006	4,570,344.39	3,836,022.95	83.93%	0.00	0.00%	3,836,022.95	83.93%
2005 - 2007	5,235,704.45	4,498,475.97	85.92%	0.00	0.00%	4,498,475.97	85.92%
2006 - 2008	5,684,846.53	5,008,745.09	88.11%	0.00	0.00%	5,008,745.09	88.11%

Montana-Dakota Utilities Company
Gas Division
396.20 POWER OPERATED EQUIPMENT

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	%	Cost of Removal Amount	%	Net Salvage Amount	%
Three - Year Rolling Bands							
1968 - 2008	21,793,051.12	17,735,933.78	81.38	21,618.58	0.10	17,714,315.20	81.28

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	4.0
Average Retirement Age (Yrs)	2.3
Years To ASL	1.7
Inflation Factor At 2.75% to ASL	1.05

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	86.60%
1994-2008	**15 - Year Trend**	79.15%
1999-2008	**10 - Year Trend**	83.23%
2004-2008	**5 - Year Trend**	93.18%

Forcasted

Gross Salvage (Five Year Trend)	93.18%
Cost Of Removal	0.10%
Net Salvage	93.08%

MONTANA-DAKOTA UTILITIES CO.
COMMON PLANT

Depreciation Study
as of December 31, 2008

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Earl M. Robinson, CDP
Principal & Director

January 28, 2010

Mr. Paul Bienek
Montana-Dakota Utilities Company
400 North Fourth Street
Bismark, ND 58501

Dear Mr. Bienek: Re: MDU Common Plant Depr. Study

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Montana-Dakota Utilities Company - Common Plant as of December 31, 2008. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2008 results in an annual depreciation expense of $2,410,513. In comparison, the application of the proposed amortization/depreciation rates to the depreciable plant in service at December 31, 2008 results in an annual amortization/depreciation expense of $1,677,496, which is a decrease of $733,017 from current rates. The composite annual depreciation rate under present rates is 5.63 percent, while the proposed pro forma composite depreciation rate is 3.92 percent.

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON, CDP

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MONTANA-DAKOTA UTILITIES COMPANY
Common Plant

Executive Summary

Table 1 on pages 2-1 to 2-2 is a comparative summary which illustrates the effect of instituting the revised depreciation rates. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Montana Dakota Utilities Company – Common Plant (the "Company") plant in service as of December 31, 2008. Both the present and proposed depreciation rates were developed utilizing the Straight Line (SL) Method, Broad Group (BG) Procedure, and the Average Remaining Life (ARL) Technique. The utilization of the recommended depreciation rates based upon the Straight Line Average Remaining Life Procedure results in the setting of depreciation rates which will continuously true up the Company's level of capital recovery over the life of each asset group. Application of this procedure, which is based upon the current best estimates of service life and net salvage together with the Company's plant in service and accrued depreciation, produces annual depreciation rates that will result in the Company recovering 100 percent of its investment -- no more, no less.

Table 1a on pages 2-3 and 2-4 summarizes the segmentation of the Company's property group's December 31, 2008 book depreciation reserves into the plant only, gross salvage, and cost of removal components.

Table 2 - Plant Only on pages 2-5 through 2-6, (which is the development of average remaining life depreciation rates for the Plant Only recovery component) provides a summary of

the detailed life estimates and service life parameters utilized in preparing the Average Remaining Life depreciation rates for each property group. The schedule provides a summary of the detailed data and narrative of the study results set forth in Sections 4 through 7. The developed depreciation rates (Column I) were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property. This study included an analysis of the content of the property groups, discussions with senior management regarding current and anticipated events that may impact the various property groups.

Table 2 - Gross Salvage on pages 2-7 through 2-8 is a similar table to Table 2 – Plant Only, except that this table develops the component level depreciation rates for the recovery of the gross salvage portion of the property cost.

Table 2 - Cost of Removal on pages 2-9 and 2-10 summarizes the depreciation recovery rates for the cost of removal segment of the total plant cost.

Table 3 on pages 2-11 and 2-12 reconciles the December 31, 2008 account level plant in service balances per books versus the balances utilized in the performance of the depreciation study. The table incorporates pending (unrecorded) retirements identified during the course of completing the depreciation study.

Likewise, Table 4, on pages 2-13 and 2-14, reconciles the December 31, 2008 book depreciation reserve balances per books versus the balances utilized in preparing the depreciation rates per this study. The table incorporates the pending (unrecorded) retirements identified in assembling the detailed accounting data for this study.

Table 5, on pages 2-15 and 2-16, contains a summary of the Company's book depreciation reserve versus the corresponding theoretical depreciation reserve as of December 31, 2008. The theoretical depreciation reserves were developed using each asset category's utility plant in service as of December 31, 2008 together with the current estimated service life characteristics and net salvage factors developed per the study.

Table 6 on page 2-17 summarizes the annual amortization rates and amounts for each of the general plant accounts for which the depreciation amortization approach is being used while Table 7 on page 2-18 through 2-31 are the supporting detail calculations that develop the amortization rates. The amortization of the investments within the selected general plant accounts is driven by the Company's ongoing difficulty to effectively track various of the property account investments that are in many cases related to a large quantity of items of corresponding small investment amounts. Due to the inability to effectively track the items, many times the items are no longer utilized but remain on the company's books and records as unrecorded retirements. Therefore, the accounting procedure for these property items it that the investments within each vintage of the applicable property group is amortized over a predetermined time period. Once attaining the stated amortization period age the asset's original cost investment will have been fully amortized, and accordingly, is retired from the company's books and records. The property accounts for which asset investment amortization is being proposed includes Account 391, 393, 394, 395, 397, and 398.

In the process of amortization of the selected general plant accounts, there are, by the very nature of average service life dispersion, vintage investments with the applicable property group which exceeds the estimated average service life / proposed amortization period. Given that each vintage of property is being amortized over the average service life an adjustment needs to be incorporated into the change over process to recover the under depreciated position of those older investments. Accordingly, the variance between the amortization starting point depreciation reserve and the Company's actual book reserve (either positive or negative) is being recorded on a straight line basis over the proposed amortization period along with the annual amortization of all other vintage investments. The amortization starting point book depreciation reserve is equal to the sum of the original cost for vintage older than the amortization period plus the calculated deprecation reserve for vintages with ages equal to or less than the amortization period. .

It is recommended that the Company continue to apply depreciation rates and maintain its book depreciation reserve on an account-level basis. The maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Maintaining the Company's depreciation records in this detail will aid in completing the various rate studies and, most importantly, clearly identifies the Company's level of capital recovery relative to each category of plant investment.

The general drivers for the proposed depreciation rates include an assessment of the Company's historical experience with regard to achieved service lives and net salvage factors. In addition, consideration is given to current and anticipated events which are anticipated to impact the Company's ability to recover its fixed capital costs related to utility plant in service utilized to provide service to the Company's customers.

The depreciation rate for each individual account changed as a result of reflecting estimates obtained through the in-depth analysis of the Company's most recent data together with an interpretation of ongoing and anticipated future events. Some of the revisions were not significant and typically reflect fine tuning of previously utilized depreciation rates while others were more substantial in nature. Several of the accounts did reflect more significant changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates.

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

The depreciation rate relative to Account 392.20 - Transportation Equipment - Cars & Trucks decreased from 13.33 percent to 4.70 percent. Contributing to the depreciation expense decrease is the change in the estimated average service life from seven to eight years while the future net salvage estimate remained at 20%. However, the more significant driver of the depreciation rate reduction is the fact that the current book depreciation reserve is currently higher than required in comparison to the current age of the property group's investment.

The remaining account/sub-accounts experienced increases and/or declines in recommended depreciation rates to a lesser degree, as noted per Table 1 of this report. This revision in annual depreciation rates and expense is the result of both changes in the estimated service lives and salvage factors, and reflects the impact of the Company's property changes since the most recent study.

With regard to the inclusion of higher negative net salvage levels in the development of proposed depreciation rates, as noted within my discussion related to net salvage both in Section 3 of the depreciation report, the level of experienced net salvage should simply be a benchmark from which to estimate future net salvage. It is highly likely that the negative net salvage amounts experienced even recently will simply be the floor above which future negative net salvage levels will increase to a higher level. To appropriately and proportionately allocate the true total asset cost (original cost adjusted for net salvage) over its applicable service life, proper consideration must be given in each accounting period, to the total costs that are anticipated to occur relative to the Company's assets that provide customer service.

Applying the proposed depreciation rates to the Company's December 31, 2008 plant in service produces annual depreciation/amortization expense of $1,677,496 which is a decrease of $733,017 from current depreciation rates.

The following summary compares the present and proposed composite depreciation rates for illustrative purposes only. The Composite Depreciation Rate should not be applied to the total Company investment inasmuch as the non-proportional change in plant investment as a result of property additions or retirements would render the composite rate inappropriate. The Table 1 schedule lists the recommended annual depreciation rates for each property account.

Present Depreciation Rates	
Depreciable Plant In Service at December 31, 2008	$42,794,460
Annual Depreciation Expense	2,410,513
Composite Annual Depreciation Rate	5.63%
Proposed Depreciation Rates	
Depreciable Plant In Service at December 31, 2008	$42,794,460
Annual Depreciation Expense	1,677,496
Composite Annual Depreciation Rate	3.92%

Table 1

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

					Proposed Rates								
		Original	Present Rates		Proposed Plant Only Rates		Proposed Gross Salv Rates		Proposed COR Rates		Total Proposed Rates		Net
Account		Cost		Annual		Annual		Annual		Annual		Annual	Change
No.	Description	12/31/08	Rate %	Accrual	Rate %	Accrual	Rate %	Accrual	Rate %	Accrual	Rate %	Accrual	Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	DEPRECIABLE PLANT												
	General Plant												
390.0	General Structures	26,865,571.47	2.93%	787,161.24	2.51%	674,325.84	0.07%	18,805.90	-0.33%	(88,656.39)	2.25%	604,475.36	(182,685.88)
	OFFICE FURNITURE & EQUIPMENT												
391.1	Office Furniture & Equipment	3,072,248.50	4.95%	152,076.30	6.75%	207,227.63	0.00%	0.00	0.00%	0.00	6.75%	207,227.63	55,151.33
391.2	Computer Equipment - Honeywell	0.00	1.52%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00
391.3	Computer Equipment - PC	2,168,689.65	23.29%	505,087.82	7.28%	157,939.09	0.00%	0.00	0.00%	0.00	7.28%	157,939.09	(347,148.73)
391.4	Computer Equipment - Prime/Sun	7,552.14	26.51%	2,002.07	0.68%	51.47	0.00%	0.00	0.00%	0.00	0.68%	51.47	(1,950.60)
391.5	Computer Equipment - Other	1,049,321.00	0.46%	4,826.88	18.40%	193,100.24	0.00%	0.00	0.00%	0.00	18.40%	193,100.24	188,273.36
	TOTAL Account 391	6,297,811.29	10.54%	663,993.07	8.87%	558,318.43	0.00%	0.00	0.00%	0.00	8.87%	558,318.43	(105,674.64)
	TRANSPORTATION EQUIPMENT												
392.1	Transportation Equipment (Trailers)	113,614.30	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00 (1)	0.00%	0.00	0.00
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	13.33%	710,040.10	9.14%	486,854.20	-4.44%	(236,502.48)	0.00%	0.00	4.70%	250,351.72	(459,688.38)
	TOTAL Account 392	5,440,246.73	13.05%	710,040.10	8.95%	486,854.20	-4.35%	(236,502.48)	0.00%	0.00	4.60%	250,351.72	(459,688.38)
393.0	Stores Equipment	45,012.16	2.80%	1,260.34	3.32%	1,494.05	0.00%	0.00	0.00%	0.00	3.32%	1,494.05	233.71
	TOOLS, SHOP & GARAGE EQ.												
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	6.11%	25,223.33	6.71%	27,719.23	0.00%	0.00	0.00%	0.00	6.71%	27,719.23	2,495.90
394.3	Vehicle Maintenance Equipment	179,785.84	4.75%	8,539.83	5.33%	9,591.43	0.00%	0.00	0.00%	0.00	5.33%	9,591.43	1,051.60
394.4	Vehicle Refueling Equipment	612,112.44	4.38%	26,810.52	3.28%	20,101.35	0.00%	0.00	0.00%	0.00	3.28%	20,101.35	(6,709.17)
	TOTAL Account 394	1,204,718.75	5.03%	60,573.68	4.77%	57,412.01	0.00%	0.00	0.00%	0.00	4.77%	57,412.01	(3,161.67)
396.2	Power Operated Equipment	53,432.48	2.69%	1,437.33	18.22%	9,735.40	-10.64%	(5,685.22)	0.00%	0.00	7.58%	4,050.18	2,612.85
	COMMUNICATION EQUIPMENT												
397.1	Radio Communication Equip. (Fixed)	379,772.93	4.99%	18,950.67	4.70%	17,844.86	0.00%	0.00	0.00%	0.00	4.70%	17,844.86	(1,105.81)
397.2	Radio Communication Equip. (Mobile)	612,124.91	4.08%	24,974.70	4.13%	25,251.65	0.00%	0.00	0.00%	0.00	4.13%	25,251.65	276.95
397.3	General Telephone Communication Equip.	496,688.56	8.72%	43,311.24	7.78%	38,662.59	0.00%	0.00	0.00%	0.00	7.78%	38,662.59	(4,648.65)
397.5	Supervisory & Telemetering Equip.	41,918.98	0.35%	146.72	4.24%	1,777.12	0.00%	0.00	0.00%	0.00	4.24%	1,777.12	1,630.40
397.8	Network Equipment	424,430.36	17.95%	76,185.25	18.95%	80,428.99	0.00%	0.00	0.00%	0.00	18.95%	80,428.99	4,243.74
	TOTAL Account 397	1,954,935.74	8.37%	163,568.58	8.39%	163,965.21	0.00%	0.00	0.00%	0.00	8.39%	163,965.21	396.63
398.0	Miscellaneous Equipment	932,731.72	2.41%	22,478.83	4.01%	37,429.17	0.00%	0.00	0.00%	0.00	4.01%	37,429.17	14,950.34
	Sub-Total (General Plant) Amortization	**10,435,209.66**	**8.74%**	**911,874.50**	**7.84%**	**818,618.87**	**0.00%**	**0.00**	**0.00%**	**0.00**	**7.84%**	**818,618.87**	**(93,255.63)**
	TOTAL General Plant	42,794,460.34	5.63%	2,410,513.17	4.65%	1,989,534.31	-0.52%	(223,381.80)	-0.21%	(88,656.39)	3.92%	1,677,496.13	(733,017.04)
	TOTAL Depreciable Plant	42,794,460.34	5.63%	2,410,513.17	4.65%	1,989,534.31	-0.52%	(223,381.80)	-0.21%	(88,656.39)	3.92%	1,677,496.13	(733,017.04)

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation Expense Under Present and Proposed Rates

			Present Rates		Proposed Rates: Proposed Plant Only Rates		Proposed Rates: Proposed Gross Salv Rates		Proposed Rates: Proposed COR Rates		Proposed Rates: Total Proposed Rates		
Account No.	Description	Original Cost 12/31/08	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Rate %	Annual Accrual	Net Change Depr.. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Amortizable Plant												
392.3	Aircraft Equipment	2,937,920.42											
	TOTAL Amortizable Plant	2,937,920.42											
	NON-DEPRECIABLE PLANT												
389.0	Land & Land Rights (General)	2,778,248.40											
	Total Land	2,778,248.40											
	INTANGIBLE PLANT												
303.0	Miscellaneous Intangible Plant	22,784,037.44											
	Total Intangible Plant	22,784,037.44											
	TOTAL Non-Depreciable Plant	25,562,285.84											
	TOTAL Plant in Service	71,294,666.60											

(1) Account Fully Depreciated. No further current depreciation accrual.

Table 1a

Montana-Dakota Utilities Company
Common Plant

Summary of Book Depreciation Reserve by Recovery Component as of December 31, 2008

Account No. (a)	Description (b)	Cost 12/31/08 (c)	Total Book Depr Reserve 12/31/08 (f)	Cost of Removal In Book Res. (g)	Gross Salvage In Book Res. (h)	Plant Only Depr Reserve 12/31/08 (i)
	DEPRECIABLE PLANT					
	General Plant					
390.0	General Structures	26,865,571.47	11,607,448.53	2,257,817.48	(494,171.21)	9,843,802.26
	OFFICE FURNITURE & EQUIPMENT					
391.1	Office Furniture & Equipment	3,072,248.50	1,438,080.62	0.00	0.00	1,438,080.62
391.2	Computer Equipment - Honeywell	0.00	0.00	0.00	0.00	0.00
391.3	Computer Equipment - PC	2,168,689.65	2,130,757.41	0.00	0.00	2,130,757.41
391.4	Computer Equipment - Prime/Sun	7,552.14	7,806.34	0.00	0.00	7,806.34
391.5	Computer Equipment - Other	1,049,321.00	467,503.87	0.00	0.00	467,503.87
	TOTAL Account 391	6,297,811.29	4,044,148.24	0.00	0.00	4,044,148.24
	TRANSPORTATION EQUIPMENT					
392.1	Transportation Equipment (Trailers)	113,614.30	152,128.67	0.00	0.00	152,128.67
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	3,135,598.94	0.00	0.00	3,135,598.94
	TOTAL Account 392	5,440,246.73	3,287,727.61	0.00	0.00	3,287,727.61
393.0	Stores Equipment	45,012.16	16,459.85	0.00	0.00	16,459.85
	TOOLS, SHOP & GARAGE EQ.					
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	161,007.16	0.00	0.00	161,007.16
394.3	Vehicle Maintenance Equipment	179,785.84	80,709.96	0.00	0.00	80,709.96
394.4	Vehicle Refueling Equipment	612,112.44	575,399.33	0.00	0.00	575,399.33
	TOTAL Account 394	1,204,718.75	817,116.45	0.00	0.00	817,116.45
396.2	Power Operated Equipment	53,432.48	7,669.90	0.00	0.00	7,669.90
	COMMUNICATION EQUIPMENT					
397.1	Radio Communication Equip. (Fixed)	379,772.93	233,451.80	0.00	0.00	233,451.80
397.2	Radio Communication Equip. (Mobile)	612,124.91	466,747.57	0.00	0.00	466,747.57
397.3	General Telephone Communication Equip.	496,688.56	368,104.63	0.00	0.00	368,104.63
397.5	Supervisory & Telemetering Equip.	41,918.98	39,621.09	0.00	0.00	39,621.09
397.8	Network Equipment	424,430.36	132,568.37	0.00	0.00	132,568.37
	TOTAL Account 397	1,954,935.74	1,240,493.46	0.00	0.00	1,240,493.46
398.0	Miscellaneous Equipment	932,731.72	449,365.65	0.00	0.00	449,365.65
	Sub-Total (General Plant) Amortization	**10,435,209.66**	**6,567,583.65**	**0.00**	**0.00**	**6,567,583.65**
	TOTAL General Plant	42,794,460.34	21,470,429.69	2,257,817.48	(494,171.21)	19,706,783.42
		13,322,877.12	8,257,442.76			
	TOTAL Depreciable Plant	42,794,460.34	21,470,429.69	2,257,817.48	(494,171.21)	19,706,783.42

Montana-Dakota Utilities Company
Common Plant

Summary of Book Depreciation Reserve by Recovery Component as of December 31, 2008

Account No. (a)	Description (b)	Cost 12/31/08 (c)	Total Book Depr Reserve 12/31/08 (f)	Cost of Removal In Book Res. (g)	Gross Salvage In Book Res. (h)	Plant Only Depr Reserve 12/31/08 (i)
	Amortizable Plant					
392.3	Aircraft Equipment	2,937,920.42	726,593.90	0.00	0.00	726,593.90
	TOTAL Amortizable Plant	2,937,920.42	726,593.90	0.00	0.00	726,593.90
	NON-DEPRECIABLE PLANT					
389.0	Land & Land Rights (General)	2,778,248.40	0.00			0.00
	Total Land	2,778,248.40	0.00	0.00	0.00	0.00
	INTANGIBLE PLANT					
303.0	Miscellaneous Intangible Plant	22,784,037.44				0.00
	Total Intangible Plant	22,784,037.44	0.00	0.00	0.00	0.00
	TOTAL Non-Depreciable Plant	25,562,285.84	0.00	0.00	0.00	0.00
	TOTAL Common Utility Plant in Service	71,294,666.60	22,197,023.59	2,257,817.48	(494,171.21)	20,433,377.32

Montana-Dakota Utilities Company

Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No.	Description	Original Cost 12/31/08	Estimated Future Net Salvage %	Estimated Future Net Salvage Amount	Original Cost Less Salvage	Book Depreciation Reserve	Net Original Cost Less Salvage	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Depr. Rate	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	DEPRECIABLE PLANT											
	General Plant											
390.0	General Structures	26,865,571.47	0%	0.00	26,865,571.47	9,843,802.26	17,021,769.21	35-R1	25.2	675,467.03	2.51%	
	OFFICE FURNITURE & EQUIPMENT											
391.1	Office Furniture & Equipment	3,072,248.50	0%	0.00	3,072,248.50	1,438,080.62	1,634,167.88	N/A	N/A	207,227.63	6.75%	*
391.2	Computer Equipment - Honeywell	0.00	0%	0.00	0.00	0.00	0.00	N/A	N/A	0.00	0.00%	*
391.3	Computer Equipment - PC	2,168,689.65	0%	0.00	2,168,689.65	2,130,757.41	37,932.24	N/A	N/A	157,939.09	7.28%	*
391.4	Computer Equipment - Prime/Sun	7,552.14	0%	0.00	7,552.14	7,806.34	-254.20	N/A	N/A	51.47	0.68%	*
391.5	Computer Equipment - Other	1,049,321.00	0%	0.00	1,049,321.00	467,503.87	581,817.13	N/A	N/A	193,100.24	18.40%	*
	TOTAL Account 391	6,297,811.29		0.00	6,297,811.29	4,044,148.24	2,253,663.05			558,318.42	8.87%	
	TRANSPORTATION EQUIPMENT											
392.1	Transportation Equipment (Trailers)	113,614.30	0%	0.00	113,614.30	152,128.67	-38,514.37	24-L1	12.6	0.00	0.00%	(1)
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	0%	0.00	5,326,632.43	3,135,598.94	2,191,033.49	8-R2	4.5	486,896.33	9.14%	
	TOTAL Account 392	5,440,246.73		0.00	5,440,246.73	3,287,727.61	2,152,519.12			486,896.33	8.95%	
393.0	Stores Equipment	45,012.16	0%	0.00	45,012.16	16,459.85	28,552.31	N/A	N/A	1,494.05	3.32%	*
	TOOLS, SHOP & GARAGE EQ.											
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	0%	0.00	412,820.47	161,007.16	251,813.31	N/A	N/A	27,719.23	6.71%	*
394.3	Vehicle Maintenance Equipment	179,785.84	0%	0.00	179,785.84	80,709.96	99,075.88	N/A	N/A	9,591.43	5.33%	*
394.4	Vehicle Refueling Equipment	612,112.44	0%	0.00	612,112.44	575,399.33	36,713.11	N/A	N/A	20,101.35	3.28%	*
	TOTAL Account 394	1,204,718.75		0.00	1,204,718.75	817,116.45	387,602.30			57,412.01	4.77%	
396.2	Power Operated Equipment	53,432.48	0%	0.00	53,432.48	7,669.90	45,762.58	10-R2	4.7	9,736.72	18.22%	
	COMMUNICATION EQUIPMENT											
397.1	Radio Communication Equip. (Fixed)	379,772.93	0%	0.00	379,772.93	233,451.80	146,321.13	N/A	N/A	17,844.86	4.70%	*
397.2	Radio Communication Equip. (Mobile)	612,124.91	0%	0.00	612,124.91	466,747.57	145,377.34	N/A	N/A	25,251.65	4.13%	*
397.3	General Telephone Communication Equip.	496,688.56	0%	0.00	496,688.56	368,104.63	128,583.93	N/A	N/A	38,662.59	7.78%	*
397.5	Supervisory & Telemetering Equip.	41,918.98	0%	0.00	41,918.98	39,621.09	2,297.89	N/A	N/A	1,777.12	4.24%	*

Montana-Dakota Utilities Company
Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No.	Description	Original Cost 12/31/08	Estimated Future Net Salvage %	Estimated Future Net Salvage Amount	Original Cost Less Salvage	Book Depreciation Reserve	Net Original Cost Less Salvage	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Depr. Rate	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
397.8	Network Equipment	424,430.36	0%	0.00	424,430.36	132,568.37	291,861.99	N/A	N/A	80,428.99	18.95%	*
	TOTAL Account 397	1,954,935.74		0.00	1,954,935.74	1,240,493.46	714,442.28			163,965.21	8.39%	
398.0	Miscellaneous Equipment	932,731.72	0%	0.00	932,731.72	449,365.65	483,366.07	N/A	N/A	37,429.17	4.01%	*
	Sub-Total (General Plant) Amortization	**10,435,209.66**		**0.00**	**10,435,209.66**	**6,567,583.65**	**3,867,626.01**			**818,618.85**	**7.84%**	
	TOTAL General Plant	42,794,460.34		0.00	42,794,460.34	19,706,783.42	23,087,676.92			1,990,718.93	4.65%	
	TOTAL Depreciable Plant	42,794,460.34		0.00	42,794,460.34	19,706,783.42	23,087,676.92			1,990,718.93	4.65%	
	<u>Amortizable Plant</u>											
392.3	Aircraft Equipment	2,937,920.42										
	TOTAL Amortizable Plant	2,937,920.42										
	<u>NON-DEPRECIABLE PLANT</u>											
389.0	Land & Land Rights (General)	2,778,248.40										
	Total Land	2,778,248.40										
	INTANGIBLE PLANT											
303.0	Miscellaneous Intangible Plant	22,784,037.44										
	Total Intangible Plant	22,784,037.44										
	TOTAL Non-Depreciable Plant	25,562,285.84										
	TOTAL Plant in Service	71,294,666.60										
	TOTAL Common Utility Plant in Service											

* Based Upon Amoritzation Rates.
(1) Account Fully Depreciated. No further current depreciation accrual.

Table 2 - GrossSalv

Montana-Dakota Utilities Company
Common Plant
Montana-Dakota Utilties Company
Summary of Original Cost of Utility Plant in Service and Calculation of
Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of
Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Depr. Rate (l)
	DEPRECIABLE PLANT										
	General Plant										
390.0	General Structures	26,865,571.47	0%	0.00	26,865,571.47	(494,171.21)	494,171.21	35-R1	25.2	19,609.97	0.07%
	OFFICE FURNITURE & EQUIPMENT										
391.1	Office Furniture & Equipment	3,072,248.50	0%	0.00	3,072,248.50	0.00	0.00	N/A	N/A	0.00	0.00% *
391.2	Computer Equipment - Honeywell	0.00	0%	0.00	0.00	0.00	0.00	N/A	N/A	0.00	0.00% *
391.3	Computer Equipment - PC	2,168,689.65	0%	0.00	2,168,689.65	0.00	0.00	N/A	N/A	0.00	0.00% *
391.4	Computer Equipment - Prime/Sun	7,552.14	0%	0.00	7,552.14	0.00	0.00	N/A	N/A	0.00	0.00% *
391.5	Computer Equipment - Other	1,049,321.00	0%	0.00	1,049,321.00	0.00	0.00	N/A	N/A	0.00	0.00% *
	TOTAL Account 391	6,297,811.29		0.00	6,297,811.29	0.00	0.00			0.00	0.00%
	TRANSPORTATION EQUIPMENT										
392.1	Transportation Equipment (Trailers)	113,614.30	20%	22,722.86	90,891.44	0.00	(22,722.86)	24-L1	12.6	0.00	0.00% (1)
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	20%	1,065,326.49	4,261,305.94	0.00	(1,065,326.49)	8-R2	4.5	(236,739.22)	-4.44%
	TOTAL Account 392	5,440,246.73		1,088,049.35	4,352,197.38	0.00	(1,088,049.35)			(236,739.22)	-4.35%
393.0	Stores Equipment	45,012.16	0%	0.00	45,012.16	0.00	0.00	N/A	N/A	0.00	0.00% *
	TOOLS, SHOP & GARAGE EQ.										
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	0%	0.00	412,820.47	0.00	0.00	N/A	N/A	0.00	0.00% *
394.3	Vehicle Maintenance Equipment	179,785.84	0%	0.00	179,785.84	0.00	0.00	N/A	N/A	0.00	0.00% *
394.4	Vehicle Refueling Equipment	612,112.44	0%	0.00	612,112.44	0.00	0.00	N/A	N/A	0.00	0.00% *
	TOTAL Account 394	1,204,718.75		0.00	1,204,718.75	0.00	0.00			0.00	0.00%
396.2	Power Operated Equipment	53,432.48	50%	26,716.24	26,716.24	0.00	(26,716.24)	10-R2	4.7	(5,684.31)	-10.64%
	COMMUNICATION EQUIPMENT										
397.1	Radio Communication Equip. (Fixed)	379,772.93	0%	0.00	379,772.93	0.00	0.00	N/A	N/A	0.00	0.00% *
397.2	Radio Communication Equip. (Mobile)	612,124.91	0%	0.00	612,124.91	0.00	0.00	N/A	N/A	0.00	0.00% *
397.3	General Telephone Communication Equip.	496,688.56	0%	0.00	496,688.56	0.00	0.00	N/A	N/A	0.00	0.00% *

Table 2 - GrossSalv

Montana-Dakota Utilities Company
Common Plant
Montana-Dakota Utilties Company
Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No.	Description	Original Cost 12/31/08	Estimated Future Net Salvage %	Estimated Future Net Salvage Amount	Original Cost Less Salvage	Book Depreciation Reserve	Net Original Cost Less Salvage	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Depr. Rate	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
397.5	Supervisory & Telemetering Equip.	41,918.98	0%	0.00	41,918.98	0.00	0.00	N/A	N/A	0.00	0.00%	*
397.8	Network Equipment	424,430.36	0%	0.00	424,430.36	0.00	0.00	N/A	N/A	0.00	0.00%	*
	TOTAL Account 397	1,954,935.74		0.00	1,954,935.74	0.00	0.00			0.00	0.00%	
398.0	Miscellaneous Equipment	932,731.72	0%	0.00	932,731.72	0.00	0.00	N/A	N/A	0.00	0.00%	*
	Sub-Total (General Plant) Amortization	**10,435,209.66**		**0.00**	**10,435,209.66**	**0.00**	**0.00**			**0.00**	**0.00%**	
	TOTAL General Plant	42,794,460.34		1,114,765.59	41,679,694.75	(494,171.21)	(620,594.38)			(222,813.56)	-0.52%	
	TOTAL Depreciable Plant	42,794,460.34		1,114,765.59	41,679,694.75	(494,171.21)	(620,594.38)			(222,813.56)	-0.52%	
	<u>Amortizable Plant</u>											
392.3	Aircraft Equipment	2,937,920.42										
	TOTAL Amortizable Plant	2,937,920.42										
	<u>NON-DEPRECIABLE PLANT</u>											
389.0	Land & Land Rights (General)	2,778,248.40										
	Total Land	2,778,248.40										
	INTANGIBLE PLANT											
303.0	Miscellaneous Intangible Plant	22,784,037.44										
	Total Intangible Plant	22,784,037.44										
	TOTAL Non-Depreciable Plant	25,562,285.84										
	TOTAL Plant in Service	71,294,666.60										
	TOTAL Common Utility Plant in Service											

* Based Upon Amoritzation Rates.
(1) Account Fully Depreciated. No further current depreciation accrual.

Montana-Dakota Utilities Company

Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No.	Description	Original Cost 12/31/08	Estimated Future Net Salvage %	Estimated Future Net Salvage Amount	Original Cost Less Salvage	Book Depreciation Reserve	Net Original Cost Less Salvage	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Depr. Rate	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	DEPRECIABLE PLANT											
	General Plant											
390.0	General Structures	26,865,571.47	0%	0.00	26,865,571.47	2,257,817.48	-2,257,817.48	35-R1	25.2	-89,595.93	-0.33%	
	OFFICE FURNITURE & EQUIPMENT											
391.1	Office Furniture & Equipment	3,072,248.50	0%	0.00	3,072,248.50	0.00	0.00	N/A	N/A	0.00	0.00%	*
391.2	Computer Equipment - Honeywell	0.00	0%	0.00	0.00	0.00	0.00	N/A	N/A	0.00	0.00%	*
391.3	Computer Equipment - PC	2,168,689.65	0%	0.00	2,168,689.65	0.00	0.00	N/A	N/A	0.00	0.00%	*
391.4	Computer Equipment - Prime/Sun	7,552.14	0%	0.00	7,552.14	0.00	0.00	N/A	N/A	0.00	0.00%	*
391.5	Computer Equipment - Other	1,049,321.00	0%	0.00	1,049,321.00	0.00	0.00	N/A	N/A	0.00	0.00%	*
	TOTAL Account 391	6,297,811.29		0.00	6,297,811.29	0.00	0.00			0.00	0.00%	
	TRANSPORTATION EQUIPMENT											
392.1	Transportation Equipment (Trailers)	113,614.30	0%	0.00	113,614.30	0.00	0.00	24-L1	12.6	0.00	0.00%	(1)
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	0%	0.00	5,326,632.43	0.00	0.00	8-R2	4.5	0.00	0.00%	
	TOTAL Account 392	5,440,246.73		0.00	5,440,246.73	0.00	0.00			0.00	0.00%	
393.0	Stores Equipment	45,012.16	0%	0.00	45,012.16	0.00	0.00	N/A	N/A	0.00	0.00%	*
	TOOLS, SHOP & GARAGE EQ.											
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	0%	0.00	412,820.47	0.00	0.00	N/A	N/A	0.00	0.00%	*
394.3	Vehicle Maintenance Equipment	179,785.84	0%	0.00	179,785.84	0.00	0.00	N/A	N/A	0.00	0.00%	*
394.4	Vehicle Refueling Equipment	612,112.44	0%	0.00	612,112.44	0.00	0.00	N/A	N/A	0.00	0.00%	*
	TOTAL Account 394	1,204,718.75		0.00	1,204,718.75	0.00	0.00			0.00	0.00%	
396.2	Power Operated Equipment	53,432.48	0%	0.00	53,432.48	0.00	0.00	10-R2	N/A	0.00	0.00%	
	COMMUNICATION EQUIPMENT											
397.1	Radio Communication Equip. (Fixed)	379,772.93	0%	0.00	379,772.93	0.00	0.00	N/A	N/A	0.00	0.00%	*
397.2	Radio Communication Equip. (Mobile)	612,124.91	0%	0.00	612,124.91	0.00	0.00	N/A	N/A	0.00	0.00%	*
397.3	General Telephone Communication Equip.	496,688.56	0%	0.00	496,688.56	0.00	0.00	N/A	N/A	0.00	0.00%	*
397.5	Supervisory & Telemetering Equip.	41,918.98	0%	0.00	41,918.98	0.00	0.00	N/A	N/A	0.00	0.00%	*

Table 2 - COR

Montana-Dakota Utilities Company
Common Plant

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2008

Account No. (a)	Description (b)	Original Cost 12/31/08 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Depr. Rate (l)	
397.8	Network Equipment	424,430.36	0%	0.00	424,430.36	0.00	0.00	N/A	N/A	0.00	0.00%	*
	TOTAL Account 397	1,954,935.74		0.00	1,954,935.74	0.00	0.00			0.00	0.00%	
398.0	Miscellaneous Equipment	932,731.72	0%	0.00	932,731.72	0.00	0.00	N/A	N/A	0.00	0.00%	*
	Sub-Total (General Plant) Amortization	**10,435,209.66**		**0.00**	**10,435,209.66**	**0.00**	**0.00**			**0.00**	**0.00%**	
	TOTAL General Plant	42,794,460.34		0.00	42,794,460.34	2,257,817.48	-2,257,817.48			-89,595.93	-0.21%	
	TOTAL Depreciable Plant	42,794,460.34		0.00	42,794,460.34	2,257,817.48	-2,257,817.48			-89,595.93	-0.21%	
	Amortizable Plant											
392.3	Aircraft Equipment	2,937,920.42										
	TOTAL Amortizable Plant	2,937,920.42										
	NON-DEPRECIABLE PLANT											
389.0	Land & Land Rights (General)	2,778,248.40										
	Total Land	2,778,248.40										
	INTANGIBLE PLANT											
303.0	Miscellaneous Intangible Plant	22,784,037.44										
	Total Intangible Plant	22,784,037.44										
	TOTAL Non-Depreciable Plant	25,562,285.84										
	TOTAL Plant in Service	71,294,666.60										
	TOTAL Common Utility Plant in Service											

* Based Upon Amoritzation Rates.
(1) Account Fully Depreciated. No further current depreciation accrual.

Montana-Dakota Utilities
Common Plant

Original Cost Per Company Books, Adjustments, And Original Cost Per Depreciation Study of December 31, 2008

Account No. (a)	Description (b)	Original Cost Per Co. Books 12/31/08 (c)	(Pending) Retirements (d)	Original Cost Per Depr Study Data 12/31/08 (e)
	DEPRECIABLE PLANT			
	General Plant			
390.0	General Structures	26,865,571.47		26,865,571.47
	OFFICE FURNITURE & EQUIPMENT			
391.1	Office Furniture & Equipment	3,072,248.50		3,072,248.50
391.2	Computer Equipment - Honeywell	0.00		0.00
391.3	Computer Equipment - PC	2,168,689.65		2,168,689.65
391.4	Computer Equipment - Prime/Sun	7,552.14		7,552.14
391.5	Computer Equipment - Other	1,049,321.00		1,049,321.00
	TOTAL Account 391	6,297,811.29	0.00	6,297,811.29
	TRANSPORTATION EQUIPMENT			
392.1	Transportation Equipment (Trailers)	113,614.30		113,614.30
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43		5,326,632.43
	TOTAL Account 392	5,440,246.73	0.00	5,440,246.73
393.0	Stores Equipment	45,012.16		45,012.16
	TOOLS, SHOP & GARAGE EQ.			
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47		412,820.47
394.3	Vehicle Maintenance Equipment	179,785.84		179,785.84
394.4	Vehicle Refueling Equipment	612,112.44		612,112.44
	TOTAL Account 394	1,204,718.75	0.00	1,204,718.75
396.2	Power Operated Equipment	53,432.48		53,432.48
	COMMUNICATION EQUIPMENT			
397.1	Radio Communication Equip. (Fixed)	379,772.93		379,772.93
397.2	Radio Communication Equip. (Mobile)	612,124.91		612,124.91
397.3	General Telephone Communication Equip.	496,688.56		496,688.56
397.5	Supervisory & Telemetering Equip.	41,918.98		41,918.98
397.8	Network Equipment	424,430.36		424,430.36
	TOTAL Account 397	1,954,935.74	0.00	1,954,935.74

Montana-Dakota Utilities
Common Plant

Original Cost Per Company Books, Adjustments, And Original Cost Per Depreciation Study of December 31, 2008

Account No. (a)	Description (b)	Original Cost Per Co. Books 12/31/08 (c)	(Pending) Retirements (d)	Original Cost Per Depr Study Data 12/31/08 (e)
398.0	Miscellaneous Equipment	932,731.72		932,731.72
	Sub-Total (General Plant) Amortization	**10,435,209.66**	**0.00**	**10,435,209.66**
	TOTAL General Plant	42,794,460.34	0.00	42,794,460.34
	TOTAL Depreciable Plant	42,794,460.34	0.00	42,794,460.34
	Amortizable Plant			
392.3	Aircraft Equipment	2,937,920.42		2,937,920.42
	TOTAL Amortizable Plant	2,937,920.42	0.00	2,937,920.42
	NON-DEPRECIABLE PLANT			
389.0	Land & Land Rights (General)	2,778,248.40		2,778,248.40
	Total Land	2,778,248.40	0.00	2,778,248.40
	INTANGIBLE PLANT			
303.0	Miscellaneous Intangible Plant	22,784,037.44		22,784,037.44
	Total Intangible Plant	22,784,037.44	0.00	22,784,037.44
	TOTAL Non-Depreciable Plant	25,562,285.84	0.00	25,562,285.84
	TOTAL Plant in Service	71,294,666.60	0.00	71,294,666.60
399.0	**ARO**	7,739.14		
	Total Including ARO	71,302,405.74		

Montana-Dakota Utilties Company
Common Plant

Summary of Book Depreciation Reserve Relative To Original Cost of Utility Plant in Service, Adjustments, And Depreciation Reserve Per Depreciation Study as of December 31, 2008

Account No. (a)	Description (b)	Depr Reserve Per Books 12/31/08 (c)	(Pending) Retirements (d)	Depr Reserve Per Depr Study 12/31/08 (e)
	DEPRECIABLE PLANT			
	General Plant			
390.00	General Structures	11,607,448.53		11,607,448.53
	OFFICE FURNITURE & EQUIPMENT			
391.10	Office Furniture & Equipment	1,438,080.62		1,438,080.62
391.20	Computer Equipment - Honeywell	0.00		0.00
391.30	Computer Equipment - PC	2,130,757.41		2,130,757.41
391.40	Computer Equipment - Prime/Sun	7,806.34		7,806.34
391.50	Computer Equipment - Other	467,503.87		467,503.87
	TOTAL Account 391	4,044,148.24	0.00	4,044,148.24
	TRANSPORTATION EQUIPMENT			
392.10	Transportation Equipment (Trailers)	152,128.67		152,128.67
392.20	Transportation Equipment (Cars & Trucks)	3,135,598.94		3,135,598.94
	TOTAL Account 392	3,287,727.61	0.00	3,287,727.61
393.00	Stores Equipment	16,459.85		16,459.85
	TOOLS, SHOP & GARAGE EQ.			
394.10	Tools, Shop & Garage Equip. (Non-Unitized)	161,007.16		161,007.16
394.30	Vehicle Maintenance Equipment	80,709.96		80,709.96
394.40	Vehicle Refueling Equipment	575,399.33		575,399.33
	TOTAL Account 394	817,116.45	0.00	817,116.45
396.20	Power Operated Equipment	7,669.90		7,669.90
	COMMUNICATION EQUIPMENT			
397.10	Radio Communication Equip. (Fixed)	233,451.80		233,451.80
397.20	Radio Communication Equip. (Mobile)	466,747.57		466,747.57
397.30	General Telephone Communication Equip.	368,104.63		368,104.63
397.50	Supervisory & Telemetering Equip.	39,621.09		39,621.09
397.80	Network Equipment	132,568.37		132,568.37
	TOTAL Account 397	1,240,493.46	0.00	1,240,493.46

Table 4

Montana-Dakota Utilties Company
Common Plant

Summary of Book Depreciation Reserve Relative To Original Cost of Utility Plant in Service, Adjustments, And Depreciation Reserve Per Depreciation Study as of December 31, 2008

Account No.	Description	Depr Reserve Per Books 12/31/08	(Pending) Retirements	Depr Reserve Per Depr Study 12/31/08
(a)	(b)	(c)	(d)	(e)
398.00	Miscellaneous Equipment	449,365.65		449,365.65
	Sub-Total (General Plant) Amortization	**6,567,583.65**		**6,567,583.65**
	TOTAL General Plant	21,470,429.69	0.00	21,470,429.69
	TOTAL Depreciable Plant	21,470,429.69	0.00	21,470,429.69
	Amortizable Plant			
392.30	Aircraft Equipment	726,593.90		726,593.90
	TOTAL Amortizable Plant	726,593.90	0.00	726,593.90
	NON-DEPRECIABLE PLANT			
389.00	Land & Land Rights (General)	0.00		0.00
	Total Land	0.00	0.00	0.00
	INTANGIBLE PLANT			
303.00	Miscellaneous Intangible Plant	15,198,858.71		15,198,858.71
	Total Intangible Plant	15,198,858.71	0.00	15,198,858.71
	TOTAL Non-Depreciable Plant	15,198,858.71	0.00	15,198,858.71
	TOTAL Plant in Service	37,395,882.30	0.00	37,395,882.30
	TOTAL Common Utility Plant in Service	37,395,882.30	0.00	37,395,882.30
399.00	ARO	4,410.12		
	Total Including ARO	37,400,292.42		

Montana-Dakota Utilities Company
Common Plant

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

Account No.	Description	Original Cost 12/31/08	Present Parameters: Net Salvage W/ COR %	Present Parameters: Net Salvage W/O COR %	Present Parameters: Gross COR %	Present Parameters: A.S.L./ Survivor Curve	Present Parameters: Present Depr. Rate-%	Present Parameters: Average Remaining Life	Proposed Parameters: Net Salvage W/ COR %	Proposed Parameters: Net Salvage W/O COR %	Proposed Parameters: Gross COR %	Proposed Parameters: A.S.L./ Survivor Curve	Proposed Parameters: Average Remaining Life
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(n)	(o)
	DEPRECIABLE PLANT												
	General Plant												
390.0	General Structures	26,865,571.47	-10%	0%	-10%	35-R3	2.93%	17.8	0%	0%	0%	35-R1	25.2
	OFFICE FURNITURE & EQUIPMENT												
391.1	Office Furniture & Equipment	3,072,248.50	0%	0%	0%	N/A	4.95%	23.8	0%	0%	0%	N/A *	*
391.2	Computer Equipment - Honeywell	0.00	0%	0%	0%	N/A	1.52%	18.6	0%	0%	0%	N/A *	*
391.3	Computer Equipment - PC	2,168,689.65	0%	0%	0%	5-R3	23.29%	26.1	0%	0%	0%	N/A *	*
391.4	Computer Equipment - Prime/Sun	7,552.14	0%	0%	0%	N/A	26.51%	27.1	0%	0%	0%	N/A *	*
391.5	Computer Equipment - Other	1,049,321.00	0%	0%	0%	N/A	0.46%	26.2	0%	0%	0%	N/A *	*
	TOTAL Account 391	6,297,811.29											
	TRANSPORTATION EQUIPMENT												
392.1	Transportation Equipment (Trailers)	113,614.30	15%	15%	0%	20-L2	0.00%	8.0	20%	20%	0%	24-L1	12.6
392.2	Transportation Equipment (Cars & Trucks)	5,326,632.43	20%	20%	0%	7-R3	13.33%	3.2	20%	20%	0%	8-R2	4.5
	TOTAL Account 392	5,440,246.73											
393.0	Stores Equipment	45,012.16	0%	0%	0%	N/A	2.80%	24.0	0%	0%	0%	N/A *	*
	TOOLS, SHOP & GARAGE EQ.												
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	0%	0%	0%	N/A	6.11%	12.6	0%	0%	0%	N/A *	*
394.3	Vehicle Maintenance Equipment	179,785.84	0%	0%	0%	N/A	4.75%	16.5	0%	0%	0%	N/A *	*
394.4	Vehicle Refueling Equipment	612,112.44	0%	0%	0%	N/A	4.38%	5.5	0%	0%	0%	N/A *	*
	TOTAL Account 394	1,204,718.75											
396.2	Power Operated Equipment	53,432.48	40%	40%	0%	10-R2	2.69%	7.6	50%	50%	0%	10-R2	4.7
	COMMUNICATION EQUIPMENT												
397.1	Radio Communication Equip. (Fixed)	379,772.93	-10%	0%	-10%	N/A	4.99%	12.3	0%	0%	0%	N/A *	*
397.2	Radio Communication Equip. (Mobile)	612,124.91	0%	0%	0%	N/A	4.08%	7.6	0%	0%	0%	N/A *	*
397.3	General Telephone Communication Equip.	496,688.56	10%	10%	0%	N/A	8.72%	9.8	0%	0%	0%	N/A *	*
397.5	Supervisory & Telemetering Equip.	41,918.98	0%	0%	0%	N/A	0.35%	9.3	0%	0%	0%	N/A *	*
397.8	Network Equipment	424,430.36	0%	0%	0%	N/A	17.95%	2.4	0%	0%	0%	N/A *	*
	TOTAL Account 397	1,954,935.74											
398.0	Miscellaneous Equipment	932,731.72	5%	5%	0%	N/A	2.41%	11.3	0%	0%	0%	N/A *	*
	Sub-Total (General Plant) Amortization	**10,435,209.66**											
	TOTAL General Plant	42,794,460.34											
	TOTAL Depreciable Plant	42,794,460.34											

Table 5

Montana-Dakota Utilities Company
Common Plant

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		Gross	A.S.L./	Present	Average	Net Salvage		Gross	A.S.L./	Average
Account		Cost	W/ COR	W/O COR	COR	Survivor	Depr.	Remaining	W/ COR	W/O COR	COR	Survivor	Remaining
No.	Description	12/31/08	%	%	%	Curve	Rate-%	Life	%	%	%	Curve	Life
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(n)	(o)
	Amortizable Plant												
392.3	Aircraft Equipment	2,937,920.42											
	TOTAL Amortizable Plant	2,937,920.42											
	NON-DEPRECIABLE PLANT												
389.0	Land & Land Rights (General)	2,778,248.40											
	Total Land	2,778,248.40											
	INTANGIBLE PLANT												
303.0	Miscellaneous Intangible Plant	22,784,037.44											
	Total Intangible Plant	22,784,037.44											
	TOTAL Non-Depreciable Plant	25,562,285.84											
	TOTAL Plant in Service	71,294,666.60											
	TOTAL Common Utility Plant in Service												

* Based Upon Amoritzation Rates.

Table 6

Montana-Dakota Utilities Company
Common Plant

Summary or Original Cost of Utility Plant in Service as of December 31, 2008
and Related Annual Depreciation/Amortization Expense
Under Present Rates and Proposed Amortization

Account No.	Description	Original Cost 12/31/08	Present Rates Rate %	Present Rates Annual Accrual	Proposed Amortization Rate %	Proposed Amortization Annual Accrual	Net Change Depr/Amort Expense
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	DEPRECIABLE GENERAL PLANT						
	OFFICE FURNITURE & EQUIPMENT						
391.1	Office Furniture & Equipment	3,072,248.50	4.95%	152,076.30	6.75%	207,227.63	55,151.33
391.2	Computer Equipment - Honeywell	0.00	1.52%	0.00	0.00%	0.00	0.00
391.3	Computer Equipment - PC	2,168,689.65	23.29%	505,087.82	7.28%	157,939.09	-347,148.73
391.4	Computer Equipment - Prime/Sun	7,552.14	26.51%	2,002.07	0.68%	51.47	-1,950.60
391.5	Computer Equipment - Other	1,049,321.00	0.46%	4,826.88	18.40%	193,100.24	188,273.36
	TOTAL Account 391	6,297,811.29	10.54%	663,993.07	8.87%	558,318.43	-105,674.64
393	Stores Equipment	45,012.16	2.80%	1,260.34	3.32%	1,494.05	233.71
	TOOLS, SHOP & GARAGE EQ.						
394.1	Tools, Shop & Garage Equip. (Non-Unitized)	412,820.47	6.11%	25,223.33	6.71%	27,719.23	2,495.90
394.3	Vehicle Maintenance Equipment	179,785.84	4.75%	8,539.83	5.33%	9,591.43	1,051.60
394.4	Vehicle Refueling Equipment	612,112.44	4.38%	26,810.52	3.28%	20,101.35	-6,709.17
	TOTAL Account 394	1,204,718.75	5.03%	60,573.68	4.77%	57,412.01	-3,161.67
	COMMUNICATION EQUIPMENT						
397.1	Radio Communication Equip. (Fixed)	379,772.93	4.99%	18,950.67	4.70%	17,844.86	-1,105.81
397.2	Radio Communication Equip. (Mobile)	612,124.91	4.08%	24,974.70	4.13%	25,251.65	276.95
397.3	General Telephone Communication Equip.	496,688.56	8.72%	43,311.24	7.78%	38,662.59	-4,648.65
397.5	Supervisory & Telemetering Equip.	41,918.98	0.35%	146.72	4.24%	1,777.12	1,630.40
397.8	Network Equipment	424,430.36	17.95%	76,185.25	18.95%	80,428.99	4,243.74
	TOTAL Account 397	1,954,935.74	8.37%	163,568.58	8.39%	163,965.21	396.63
398	Miscellaneous Equipment	932,731.72	2.41%	22,478.83	4.01%	37,429.17	14,950.34
	Total (General Plant) Amortization	**10,435,209.66**	8.74%	**911,874.50**	7.84%	**818,618.87**	**-93,255.63**

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 391.10 - Office Furniture & Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve	-	Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1984	0.00		(1)	0.00	0.00	0	0.00
1985	0.00		(1)	0.00	0.00	0	0.00
1986	45,696.95	43,336	(1)	45,696.95	0.00	0	0.00
1987	53,529.26	49,935	(1)	53,529.26	0.00	0	0.00
1988	37,935.93	34,767	(1)	37,935.93	0.00	0	0.00
1989	38,772.08	34,890	(1)	38,772.08	0.00	0	0.00
1990	180,639.88	159,341	(1)	180,639.88	0.00	0	0.00
1991	70,628.94	60,892	(1)	70,628.94	0.00	0	0.00
1992	49,442.10	41,489	(1)	49,442.10	0.00	0	0.00
1993	108,531.32	88,160	(1)	108,531.32	0.00	0	0.00
1994	95,346.22	74,491	(2)	74,491.00	20,855.22	1	20,855.22
1995	76,776.57	57,269	(2)	57,269.00	19,507.57	2	9,753.79
1996	104,629.04	73,923	(2)	73,923.00	30,706.04	3	10,235.35
1997	234,174.95	155,372	(2)	155,372.00	78,802.95	4	19,700.74
1998	108,233.34	66,794	(2)	66,794.00	41,439.34	5	8,287.87
1999	194,687.24	110,566	(2)	110,566.00	84,121.24	6	14,020.21
2000	252,426.48	130,290	(2)	130,290.00	122,136.48	7	17,448.07
2001	289,131.78	133,570	(2)	133,570.00	155,561.78	8	19,445.22
2002	115,776.45	46,960	(2)	46,960.00	68,816.45	9	7,646.27
2003	188,093.59	65,314	(2)	65,314.00	122,779.59	10	12,277.96
2004	184,233.94	52,879	(2)	52,879.00	131,354.94	11	11,941.36
2005	252,275.26	56,815	(2)	56,815.00	195,460.26	12	16,288.36
2006	123,948.87	20,089	(2)	20,089.00	103,859.87	13	7,989.22
2007	175,417.75	17,162	(2)	17,162.00	158,255.75	14	11,303.98
2008	91,920.56	3,012	(2)	3,012.00	88,908.56	15	5,927.24
	3,072,248.50	1,577,316.00		1,649,682.46	1,422,566.04	6.29%	193,120.84

Book Reserve	1,438,080.62		
Starting Point Depreciation Reserve	1,649,682.46		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	211,601.84	15	14,106.79
Total Amortization Amount		6.75%	207,227.63

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 391.30 - Computer Equipment - PC

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve	-	Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2002	0.00		(1)	0.00	0.00	**0**	0.00
2003	173,271.52	143,359	(1)	173,271.52	0.00	**0**	0.00
2004	336,831.28	249,528	(2)	249,528.00	87,303.28	**1**	87,303.28
2005	0.00		(2)	0.00	0.00	**2**	0.00
2006	839,662.49	387,147	(2)	387,147.00	452,515.49	**3**	150,838.50
2007	565,694.34	162,202	(2)	162,202.00	403,492.34	**4**	100,873.09
2008	253,230.02	24,769	(2)	24,769.00	228,461.02	**5**	45,692.20
	2,168,689.65	967,005.00		996,917.52	1,171,772.13	17.74%	384,707.07
Book Reserve				2,130,757.41			
Starting Point Depreciation Reserve				996,917.52			
Book/Amortization Starting Point Depr Reserve Vari (Amortize over Amortization Period)				-1,133,839.89		5	-226,767.98
Total Amortization Amount						7.28%	157,939.09

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 391.40 - Computer Equipment - Prime/Sun

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2002	5,426.78	4,761	(2)	4,761.00	665.78	0	0.00
2003	67.09	56	(2)	56.00	11.09	0	0.00
2004	0.00	0	(2)	0.00	0.00	1	0.00
2005	2,058.27	1,266	(2)	1,266.00	792.27	2	396.14
2006	0.00	0	(2)	0.00	0.00	3	0.00
2007	0.00	0	(2)	0.00	0.00	4	0.00
2008	0.00	0	(2)	0.00	0.00	5	0.00
	7,552.14	6,083.00		6,083.00	1,469.14	5.25%	396.14

Book Reserve	7,806.34		
Starting Point Depreciation Reserve	6,083.00		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	-1,723.34	5	-344.67
Total Amortization Amount		0.68%	51.47

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 391.50 - Computer Equipment - Other

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2002	0.00		(1)	0.00	0.00	0	0.00
2003	9,649.33	7,984	(1)	9,649.33	0.00	0	0.00
2004	21,226.64	15,725	(2)	15,725.00	5,501.64	1	5,501.64
2005	130,826.48	80,456	(2)	80,456.00	50,370.48	2	25,185.24
2006	782,339.79	360,717	(2)	360,717.00	421,622.79	3	140,540.93
2007	28,263.63	8,104	(2)	8,104.00	20,159.63	4	5,039.91
2008	77,015.13	7,533	(2)	7,533.00	69,482.13	5	13,896.43
	1,049,321.00	480,519.00		482,184.33	567,136.67	18.12%	190,164.14
Book Reserve				467,503.87			
Starting Point Depreciation Reserve				482,184.33			
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)				14,680.46		5	2,936.09
Total Amortization Amount						18.40%	193,100.24

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 393- Stores Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **30** R2
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1993	1,925.33	824	(2)	824.00	1,101.33	**15**	73.42
1994	0.00	0	(2)	0.00	0.00	**16**	0.00
1995	9,542.29	3,606	(2)	3,606.00	5,936.29	**17**	349.19
1996	3,495.87	1,232	(2)	1,232.00	2,263.87	**18**	125.77
1997	18,728.58	6,111	(2)	6,111.00	12,617.58	**19**	664.08
1998	175.14	53	(2)	53.00	122.14	**20**	6.11
1999	0.00	0	(2)	0.00	0.00	**21**	0.00
2000	0.00	0	(2)	0.00	0.00	**22**	0.00
2001	6,759.17	1,474	(2)	1,474.00	5,285.17	**23**	229.79
2002	0.00	0	(2)	0.00	0.00	**24**	0.00
2003	0.00	0	(2)	0.00	0.00	**25**	0.00
2004	0.00	0	(2)	0.00	0.00	**26**	0.00
2005	0.00	0	(2)	0.00	0.00	**27**	0.00
2006	0.00	0	(2)	0.00	0.00	**28**	0.00
2007	4,385.78	197	(2)	197.00	4,188.78	**29**	144.44
2008	0.00	0	(2)	0.00	0.00	**30**	0.00
	45,012.16	13,497.00		13,497.00	31,515.16	3.54%	1,592.81

Book Reserve	16,459.85		
Starting Point Depreciation Reserve	13,497.00		
Book/Amortization Starting Point Depr Reserve Vari (Amortize over Amortization Period)	-2,962.85	30	-98.76
Total Amortization Amount		3.32%	1,494.05

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 394.1 - Tools, Shop & Garage Equipment (Non-Unitized)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **18** R2
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1964	0.00	0	(1)	0.00	0.00	**0**	0.00
1992	12,015.67	8,186	(2)	8,186.00	3,829.67	**2**	1,914.84
1993	4,687.63	3,053	(2)	3,053.00	1,634.63	**3**	544.88
1994	78,684.31	48,741	(2)	48,741.00	29,943.31	**4**	7,485.83
1995	560.01	328	(2)	328.00	232.01	**5**	46.40
1996	13,482.62	7,424	(2)	7,424.00	6,058.62	**6**	1,009.77
1997	17,077.88	8,775	(2)	8,775.00	8,302.88	**7**	1,186.13
1998	44,493.69	21,157	(2)	21,157.00	23,336.69	**8**	2,917.09
1999	18,449.52	8,040	(2)	8,040.00	10,409.52	**9**	1,156.61
2000	14,608.41	5,765	(2)	5,765.00	8,843.41	**10**	884.34
2001	28,909.25	10,185	(2)	10,185.00	18,724.25	**11**	1,702.20
2002	0.00	0	(2)	0.00	0.00	**12**	0.00
2003	1,928.41	509	(2)	509.00	1,419.41	**13**	109.19
2004	22,351.92	4,875	(2)	4,875.00	17,476.92	**14**	1,248.35
2005	48,224.46	8,258	(2)	8,258.00	39,966.46	**15**	2,664.43
2006	43,803.99	5,406	(2)	5,406.00	38,397.99	**16**	2,399.87
2007	15,616.53	1,166	(2)	1,166.00	14,450.53	**17**	850.03
2008	47,926.17	1,203	(2)	1,203.00	46,723.17	**18**	2,595.73
	412,820.47	143,071.00		143,071.00	269,749.47	6.96%	28,715.69
Book Reserve				161,007.16			
Starting Point Depreciation Reserve				143,071.00			
Book/Amortization Starting Point Depr Reserve Varianc (Amortize over Amortization Period)				-17,936.16		18	-996.45
Total Amortization Amount						6.71%	27,719.23

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 394.3 - Vehicle Maintenance Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **20** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1988	369.59	315	(1)	369.59	0.00	0	0.00
1989	760.65	634	(1)	634.00	126.65	1	126.65
1991	32,309.61	25,339	(2)	25,339.00	6,970.61	3	2,323.54
1992	376.22	284	(2)	284.00	92.22	4	23.06
1993	22,016.33	15,931	(2)	15,931.00	6,085.33	5	1,217.07
1994	19,130.19	13,184	(2)	13,184.00	5,946.19	6	991.03
1994	0.00	0	(2)	0.00	0.00	6	0.00
1995	0.00	0	(2)	0.00	0.00	7	0.00
1996	0.00	0	(2)	0.00	0.00	8	0.00
1997	0.00	0	(2)	0.00	0.00	9	0.00
1998	15,978.08	8,458	(2)	8,458.00	7,520.08	10	752.01
1999	3,603.02	1,747	(2)	1,747.00	1,856.02	11	168.73
2000	5,963.88	2,617	(2)	2,617.00	3,346.88	12	278.91
2001	2,238.57	876	(2)	876.00	1,362.57	13	104.81
2002	0.00	0	(2)	0.00	0.00	14	0.00
2003	9,575.67	2,797	(2)	2,797.00	6,778.67	15	451.91
2004	3,101.37	747	(2)	747.00	2,354.37	16	147.15
2005	0.00	0	(2)	0.00	0.00	17	0.00
2006	8,048.09	1,090	(2)	1,090.00	6,958.09	18	386.56
2007	56,314.57	4,597	(2)	4,597.00	51,717.57	19	2,721.98
2008	0.00	0	(2)	0.00	0.00	20	0.00
	179,785.84	78,616.00		78,670.59	101,115.25	5.39%	9,693.39

Book Reserve	80,709.96		
Starting Point Depreciation Reserve	78,670.59		
Book/Amortization Starting Point Depr Reserve Varian((Amortize over Amortization Period)	-2,039.37	20	-101.97
Total Amortization Amount		5.33%	9,591.43

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 394.4 - Vehicle Refueling Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 20 R3
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1986	243,205.76	206,460	(1)	243,205.76	0.00	0	0.00
1987	3,402.61	2,825	(1)	3,402.61	0.00	0	0.00
1988	2,890.28	2,339	(1)	2,890.28	0.00	0	0.00
1989	0.00	0	(2)	0.00	0.00	1	0.00
1990	0.00	0	(2)	0.00	0.00	2	0.00
1991	133,128.79	97,432	(2)	97,432.00	35,696.79	3	11,898.93
1992	71,092.77	49,879	(2)	49,879.00	21,213.77	4	5,303.44
1993	0.00	0	(2)	0.00	0.00	5	0.00
1994	0.00	0	(2)	0.00	0.00	6	0.00
1995	0.00	0	(2)	0.00	0.00	7	0.00
1996	61,784.64	34,705	(2)	34,705.00	27,079.64	8	3,384.96
1997	18.20	10	(2)	10.00	8.20	9	0.91
1998	27,961.71	13,495	(2)	13,495.00	14,466.71	10	1,446.67
1999	0.00	0	(2)	0.00	0.00	11	0.00
2000	0.00	0	(2)	0.00	0.00	12	0.00
2001	64,813.03	22,986	(2)	22,986.00	41,827.03	13	3,217.46
2002	0.00	0	(2)	0.00	0.00	14	0.00
2003	0.00	0	(2)	0.00	0.00	15	0.00
2004	0.00	0	(2)	0.00	0.00	16	0.00
2005	3,814.65	649	(2)	649.00	3,165.65	17	186.21
2006	0.00	0	(2)	0.00	0.00	18	0.00
2007	0.00	0	(2)	0.00	0.00	19	0.00
2008	0.00	0	(2)	0.00	0.00	20	0.00
	612,112.44	430,780.00		468,654.65	143,457.79	4.16%	25,438.59

Book Reserve	575,399.33		
Starting Point Depreciation Reserve	468,654.65		
Book/Amortization Starting Point Depr Reserve Variar (Amortize over Amortization Period)	-106,744.68	20	-5,337.23
Total Amortization Amount		3.28%	20,101.35

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 397.1 - Radio Communication Equipment (Fixed)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1985	0.00	0	(1)	0.00	0.00	0	0.00
1986	0.00	0	(1)	0.00	0.00	0	0.00
1987	32,797.40	30,595	(1)	32,797.40	0.00	0	0.00
1988	52,271.97	47,905	(1)	52,271.97	0.00	0	0.00
1989	13,037.79	11,732	(1)	13,037.79	0.00	0	0.00
1990	0.00	0	(1)	0.00	0.00	0	0.00
1991	0.00	0	(1)	0.00	0.00	0	0.00
1992	0.00	0	(1)	0.00	0.00	0	0.00
1993	0.00	0	(1)	0.00	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	0.00	0	(2)	0.00	0.00	2	0.00
1996	30,098.37	21,265	(2)	21,265.00	8,833.37	3	2,944.46
1997	9,884.40	6,558	(2)	6,558.00	3,326.40	4	831.60
1998	2,978.64	1,838	(2)	1,838.00	1,140.64	5	228.13
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	71,469.03	36,889	(2)	36,889.00	34,580.03	7	4,940.00
2001	11,131.90	5,143	(2)	5,143.00	5,988.90	8	748.61
2002	27,105.71	10,994	(2)	10,994.00	16,111.71	9	1,790.19
2003	2,425.10	842	(2)	842.00	1,583.10	10	158.31
2004	25,355.96	7,278	(2)	7,278.00	18,077.96	11	1,643.45
2005	16,932.68	3,813	(2)	3,813.00	13,119.68	12	1,093.31
2006	62,107.36	10,066	(2)	10,066.00	52,041.36	13	4,003.18
2007	6,771.94	663	(2)	663.00	6,108.94	14	436.35
2008	15,404.68	505	(2)	505.00	14,899.68	15	993.31
	379,772.93	196,086.00		203,961.16	175,811.77	5.22%	19,810.91

Book Reserve	233,451.80		
Starting Point Depreciaition Reserve	203,961.16		
Book/Amortization Starting Point Depr Reserve Variance (Amortize over Amortization Period)	-29,490.64	15	-1,966.04
Total Amortization Amount		4.70%	17,844.86

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 397.2 - Radio Communication Equipment (Mobile)

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **15** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1985	0.00	0	(1)	0.00	0.00	0	0.00
1986	758.41	719	(1)	758.41	0.00	0	0.00
1987	0.00	0	(1)	0.00	0.00	0	0.00
1988	0.00	0	(1)	0.00	0.00	0	0.00
1989	0.00	0	(1)	0.00	0.00	0	0.00
1990	0.00	0	(1)	0.00	0.00	0	0.00
1991	52,239.07	45,037	(1)	52,239.07	0.00	0	0.00
1992	69,736.92	58,520	(1)	69,736.92	0.00	0	0.00
1993	8,307.56	6,748	(1)	8,307.56	0.00	0	0.00
1994	0.00	0	(2)	0.00	0.00	1	0.00
1995	164.09	122	(2)	122.00	42.09	2	21.04
1996	51,987.11	36,730	(2)	36,730.00	15,257.11	3	5,085.70
1997	10,478.24	6,952	(2)	6,952.00	3,526.24	4	881.56
1998	27,953.14	17,251	(2)	17,251.00	10,702.14	5	2,140.43
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	180,485.36	93,157	(2)	93,157.00	87,328.36	7	12,475.48
2001	40,400.26	18,664	(2)	18,664.00	21,736.26	8	2,717.03
2002	10,689.91	4,336	(2)	4,336.00	6,353.91	9	705.99
2003	15,641.54	5,431	(2)	5,431.00	10,210.54	10	1,021.05
2004	43,014.80	12,346	(2)	12,346.00	30,668.80	11	2,788.07
2005	8,242.00	1,856	(2)	1,856.00	6,386.00	12	532.17
2006	0.00	0	(2)	0.00	0.00	13	0.00
2007	1,255.68	123	(2)	123.00	1,132.68	14	80.91
2008	90,770.82	2,975	(2)	2,975.00	87,795.82	15	5,853.05
	612,124.91	310,967.00		330,984.96	281,139.95	5.60%	34,302.49

Book Reserve	466,747.57		
Starting Point Depreciation Reserve	330,984.96		
Book/Amortization Starting Point Depr Reserve Varia	-135,762.61	15	-9,050.84
(Amortize over Amortization Period)			
Total Amortization Amount		4.13%	25,251.65

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 397.3 - General Telephone Communication Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 10 R2
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1995	0.00	0	(1)	0.00	0.00	0	0.00
1996	14.25	12	(1)	14.25	0.00	0	0.00
1997	204,550.06	160,731	(1)	204,550.06	0.00	0	0.00
1998	31,208.98	23,239	(1)	31,208.98	0.00	0	0.00
1999	10,343.81	7,215	(2)	7,215.00	3,128.81	1	3,128.81
2000	83,627.04	53,885	(2)	53,885.00	29,742.04	2	14,871.02
2001	68,042.27	39,829	(2)	39,829.00	28,213.27	3	9,404.42
2002	10,352.75	5,393	(2)	5,393.00	4,959.75	4	1,239.94
2003	46,091.81	20,814	(2)	20,814.00	25,277.81	5	5,055.56
2004	10,708.05	4,044	(2)	4,044.00	6,664.05	6	1,110.68
2005	16,407.75	4,918	(2)	4,918.00	11,489.75	7	1,641.39
2006	15,341.79	3,345	(2)	3,345.00	11,996.79	8	1,499.60
2007	0.00	0	(2)	0.00	0.00	9	0.00
2008	0.00	0	(2)	0.00	0.00	10	0.00
	496,688.56	323,425.00		375,216.29	121,472.27	7.64%	37,951.42

Book Reserve	368,104.63		
Starting Point Depreciation Reserve	375,216.29		
Book/Amortization Starting Point Depr Reserve Vari (Amortize over Amortization Period)	7,111.66	10	711.17
Total Amortization Amount		7.78%	38,662.59

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 397.5 - Supervisory & Telemetering Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): 15 L1
Calculation Year: 2008

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1997	0.00	0	(2)	0.00	0.00	4	0.00
1998	2,188.47	939	(2)	939.00	1,249.47	5	249.89
1999	0.00	0	(2)	0.00	0.00	6	0.00
2000	0.00	0	(2)	0.00	0.00	7	0.00
2001	37,728.69	13,205	(2)	13,205.00	24,523.69	8	3,065.46
2002	0.00	0	(2)	0.00	0.00	9	0.00
2003	0.00	0	(2)	0.00	0.00	10	0.00
2004	0.00	0	(2)	0.00	0.00	11	0.00
2005	2,001.82	395	(2)	395.00	1,606.82	12	133.90
2006	0.00	0	(2)	0.00	0.00	13	0.00
2007	0.00	0	(2)	0.00	0.00	14	0.00
2008	0.00	0	(2)	0.00	0.00	15	0.00
	41,918.98	14,539.00		14,539.00	27,379.98	8.23%	3,449.26

Book Reserve	39,621.09		
Starting Point Depreciation Reserve	14,539.00		
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)	-25,082.09	15	-1,672.14
Total Amortization Amount		4.24%	1,777.12

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 397.8 - Network Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **5** R3
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
2002	0.00	0	(1)	0.00	0.00	0	0.00
2003	0.00	0	(1)	0.00	0.00	0	0.00
2004	55,118.73	40,833	(2)	40,833.00	14,285.73	1	14,285.73
2005	29,852.49	18,359	(2)	18,359.00	11,493.49	2	5,746.75
2006	77,862.05	35,900	(2)	35,900.00	41,962.05	3	13,987.35
2007	44,443.40	12,743	(2)	12,743.00	31,700.40	4	7,925.10
2008	217,153.69	21,241	(2)	21,241.00	195,912.69	5	39,182.54
	424,430.36	129,076.00		129,076.00	295,354.36	19.11%	81,127.46

Book Reserve	132,568.37		
Starting Point Depreciation Reserve	129,076.00		
Book/Amortization Starting Point Depr Reserve Varia (Amortize over Amortization Period)	-3,492.37	5	-698.47
Total Amortization Amount		18.95%	80,428.99

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

Table 7

Montana-Dakota Utilities Company
Common Plant
Account 398.00 - Miscellaneous Equipment

Development of Annual Amortization Amount Over Estimated Average Life of Property

Average Service Life-Amortiztion (Years): **20** R2
Calculation Year: **2008**

Year	Original Cost 12-31	Calculated Reserve		Amortization Starting Depr. Reserve	Remaining AmountTo Be Amortized	Remaining Amortization Period (Yrs)	Annual Amortization Amount
1978	0.00	0	(1)	0.00	0.00	0	0.00
1979	0.00	0	(1)	0.00	0.00	0	0.00
1980	4,066.70	3,572	(1)	4,066.70	0.00	0	0.00
1981	6,371.25	5,503	(1)	6,371.25	0.00	0	0.00
1982	8,118.33	6,887	(1)	8,118.33	0.00	0	0.00
1983	4,971.62	4,138	(1)	4,971.62	0.00	0	0.00
1984	4,809.36	3,921	(1)	4,809.36	0.00	0	0.00
1985	7,165.93	5,712	(1)	7,165.93	0.00	0	0.00
1986	14,352.71	11,163	(1)	14,352.71	0.00	0	0.00
1987	41,087.40	31,100	(1)	41,087.40	0.00	0	0.00
1988	5,680.41	4,173	(1)	5,680.41	0.00	0	0.00
1989	27,362.82	19,454	(2)	27,362.82	0.00	1	0.00
1990	43,519.58	29,844	(2)	43,519.58	0.00	2	0.00
1991	11,719.06	7,723	(2)	11,719.06	0.00	3	0.00
1992	6,337.32	3,998	(2)	3,998.00	2,339.32	4	584.83
1993	35,426.75	21,300	(2)	21,300.00	14,126.75	5	2,825.35
1994	17,264.22	9,846	(2)	9,846.00	7,418.22	6	1,236.37
1995	34,402.42	18,507	(2)	18,507.00	15,895.42	7	2,270.77
1996	24,449.82	12,334	(2)	12,334.00	12,115.82	8	1,514.48
1997	31,707.42	14,892	(2)	14,892.00	16,815.42	9	1,868.38
1998	8,056.46	3,495	(2)	3,495.00	4,561.46	10	456.15
1999	16,245.36	6,446	(2)	6,446.00	9,799.36	11	890.85
2000	41,398.58	14,853	(2)	14,853.00	26,545.58	12	2,212.13
2001	126,423.64	40,420	(2)	40,420.00	86,003.64	13	6,615.66
2002	61,403.93	17,179	(2)	17,179.00	44,224.93	14	3,158.92
2003	15,169.18	3,624	(2)	3,624.00	11,545.18	15	769.68
2004	17,164.96	3,385	(2)	3,385.00	13,779.96	16	861.25
2005	12,168.05	1,881	(2)	1,881.00	10,287.05	17	605.12
2006	222,612.15	24,784	(2)	24,784.00	197,828.15	18	10,990.45
2007	26,392.51	1,776	(2)	1,776.00	24,616.51	19	1,295.61
2008	56,883.78	1,286	(2)	1,286.00	55,597.78	20	2,779.89
	932,731.72	333,196.00		379,231.17	553,500.55	4.39%	40,935.89

Book Reserve	449,365.65		
Starting Point Depreciation Reserve	379,231.17		
Book/Amortization Starting Point Depr Reserve Varianc (Amortize over Amortization Period)	-70,134.48	20	-3,506.72
Total Amortization Amount		4.01%	37,429.17

(1) Amortization starting point depreciation reserve set equal to original cost
(2) Amortization starting point depreciation reserve set equal to calculated depreciation reserve

MONTANA-DAKOTA UTILITIES

Common Plant

General

This report sets forth the results of our study of the depreciable property of Montana-Dakota Utilities – Common Plant (MDU or the Company) as of December 31, 2008 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2008.

The scope of the study included an analysis of MDU's historical data through December 31, 2008, discussions with Company management and staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant. The service lives and life characteristics resulting from the in-depth study were utilized together with the Company's plant in service and book depreciation reserve to determine the recommended Average Remaining Life (ARL) depreciation rates for the Company's plant in service as of December 31, 2008.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the MDU's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property.

The Company maintains property records containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line Group Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Average Remaining Life Technique.

The distinction between the Whole Life and Remaining Life Techniques is that under the Whole Life Technique, the depreciation rate is based on the recovery of the investment and average net salvage over the average service life of the property group. In comparison, under the Average Remaining Life Technique, the resulting annual depreciation rate incorporates the recovery of the investment (and future net salvage) less any recovery experienced to date over the average remaining life of the property group.

That is, the Average Remaining Life technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. As the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's average remaining life depreciation rate in subsequent years will be increased or decreased to compensate for the variance, thereby, assuring full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be recognized is based upon the remaining productive life over which the un-depreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Average Remaining Life Technique, the Company will recover the un-depreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintage surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the ARL technique meets the objective of providing a straight line recovery of the un-depreciated fixed capital property investment.

The use of the Average Remaining Life Technique results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by the end of the life of the property. The annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group Depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption that the retired property was at average service life.

Group Depreciation Procedures

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

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average life of the overall property group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is viewed as being the more definitive procedure for identifying the life characteristics of utility property and as a basis for developing service lives and depreciation rates, nevertheless, the Broad Group procedure is more widely utilized throughout the utility industry by regulatory commissions as a basis for depreciation rates. That is, the ELG Procedure is more definitive because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby not only reducing the risk of incomplete cost recovery, but also resulting in less return on rate base over the life of a depreciable group. The total depreciation expense over the life of the property is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the Equal Life Group procedure has been known to depreciation experts for many years, widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at

XYZ UTILITY COMPANY

CALCULATION OF ASL, ARL AND ACCRUED DEPRECIATION FACTORS — Table 8

BASED UPON AN NEW YORK STATE (KIMBALL) h3.00 CURVE USING THE EQUAL LIFE GROUP (ELG) PROCEDURE

							EQUAL LIFE GROUP PROCEDURE			
AGE AT BEGIN OF INTERVAL	LIFE TABLE BEGIN OF INTERVAL	RETIREMENT DURING INTERVAL	AVERAGE SURVIVING	AGE OF AMOUNT RETIRED	AMOUNT FOR EACH LIFE GROUP	AMOUNT FOR REMAINING LIFE GROUPS	AVERAGE SERVICE LIFE	AVERAGE REMAINING LIFE	ELG/ARL DEPR RATE	ACCRUED DEPR RES FACTOR
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
0.0	1.0000000	0.0006400	0.9996800	0.25	0.0006400	0.0587873	8.50	8.50	11.76	0.0000000
0.5	0.9993600	0.0029600	0.9978800	1.0	0.0029600	0.1148146	8.69	8.19	11.51	0.0575293
1.5	0.9964000	0.0064000	0.9932000	2.0	0.0032000	0.1117346	8.89	7.39	11.25	0.1687494
2.5	0.9900000	0.0126200	0.9836900	3.0	0.0042067	0.1080313	9.11	6.61	10.98	0.2745562
3.5	0.9773800	0.0227600	0.9660000	4.0	0.0056900	0.1030830	9.37	5.87	10.67	0.3734890
4.5	0.9546200	0.0375500	0.9358450	5.0	0.0075100	0.0964830	9.70	5.20	10.31	0.4639372
5.5	0.9170700	0.0566100	0.8887650	6.0	0.0094350	0.0880105	10.10	4.60	9.90	0.5446406
6.5	0.8604600	0.0780600	0.8214300	7.0	0.0111514	0.0777172	10.57	4.07	9.46	0.6149789
7.5	0.7824000	0.0984200	0.7331900	8.0	0.0123025	0.0659903	11.11	3.61	9.00	0.6750325
8.5	0.6839800	0.1134200	0.6272700	9.0	0.0126022	0.0535379	11.72	3.22	8.54	0.7254808
9.5	0.5705600	0.1195400	0.5107900	10.0	0.0119540	0.0412598	12.38	2.88	8.08	0.7673764
10.5	0.4510200	0.1151700	0.3934350	11.0	0.0104700	0.0300478	13.09	2.59	7.64	0.8019165
11.5	0.3358500	0.1014600	0.2851200	12.0	0.0084550	0.0205853	13.85	2.35	7.22	0.8302857
12.5	0.2343900	0.0817300	0.1935250	13.0	0.0062869	0.0132143	14.65	2.15	6.83	0.8535298
13.5	0.1526600	0.0601800	0.1225700	14.0	0.0042986	0.0079216	15.47	1.97	6.46	0.8724942
14.5	0.0924800	0.0405200	0.0722200	15.0	0.0027013	0.0044216	16.33	1.83	6.12	0.8877583
15.5	0.0519600	0.0249500	0.0394850	16.0	0.0015594	0.0022913	17.23	1.73	5.80	0.8994571
16.5	0.0270100	0.0140400	0.0199900	17.0	0.0008259	0.0010987	18.19	1.69	5.50	0.9068526
17.5	0.0129700	0.0072300	0.0093550	18.0	0.0004017	0.0004849	19.29	1.79	5.18	0.9070652
18.5	0.0057400	0.0000000	0.0057400	19.0	0.0000000	0.0002841	20.21	1.71	4.95	0.9155172
19.5	0.0057400	0.0048600	0.0033100	20.0	0.0002430	0.0001626	20.36	0.86	4.91	0.9576667
20.5	0.0008800	0.0005800	0.0005900	21.0	0.0000276	0.0000272	21.65	1.15	4.62	0.9467615
21.5	0.0003000	0.0002000	0.0002000	22.0	0.0000091	0.0000089	22.49	0.99	4.45	0.9560277
22.5	0.0001000	0.0001000	0.0000500	23.0	0.0000043	0.0000022	23.00	0.50	4.35	0.9782609
23.5	0.0000000	0.0000000	0.0000000	24.0	0.0000000	0.0000000				
		1.0000000				1.0000000				

the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column (B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 1/2 to 4 1/2, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 1/2 to 5 1/2 and experiences a service life of five years. Furthermore, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. In as much as additions retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to .5 must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover 100% of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34% (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

Remaining Life Technique

As previously noted, while I prefer the Average Remaining Life Technique (because it considers all factors in developing the applicable depreciation rates) the NY Commission and its staff have indicated that the Whole Life depreciation Technique should be used to develop depreciation rates other than for Electric generating facilities.

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant less (U) the accumulated provision for depreciation less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining lives are determined for each depreciable group, (i.e., property account).

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is determined by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R \text{ Group} = \frac{\sum D/L \times E}{\sum D/L}$$

The accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account as per this report, was obtained from the Company's books and records.

Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant, as well as normal environmental clean up costs associated with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

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

Many retired assets generate little, if any, positive salvage. Instead, many of the Company's asset property groups generate negative net salvage at end of their life as a result of the cost of removal (retirement).

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

The Company's historical net salvage experience was analyzed to identify the historical net salvage factor for each applicable property group. This analysis routinely identifies that historical retirements have occurred at average ages significantly prior to the property group's average service life. This occurrence of historical retirements, at an age which is significantly younger than the average service life of the property category, clearly demonstrates that the historical data does not appropriately recognize the true level of retirement cost at the end of the property's useful life. An additional level of cost to retire will occur due to the passage of time until all the current in service plant is retired at end of life. That is, the level of retirement costs will increase over time until the average service life is attained. The estimated additional inflation, within the estimate of retirement cost, is related to those additional year's cost increases (primarily higher labor costs over time) that will occur prior to the end of the property group's average life.

To provide an additional explanation of the issue, several general principles surrounding property retirements and related net salvage need to be highlighted. Those are that as property continues to age, the retirement of assets, if generating positive salvage when retired, will typically generate a lower percent of positive salvage. By comparison, if the class of property is one that typically generates negative net salvage (cost of removal), with increasing age at retirement the negative percentage as related to original cost will typically be greater. This situation is routinely driven by the higher labor cost with the passage of time.

Next, a simple example will aid in a better understanding of the above discussed net salvage analysis and the required adjustment to the historical analysis results. Assume the following scenario. A company has two (2) 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 (2 Yrs. Plus 10 Yrs./2). 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 analysis indication is incorrect and 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 with the majority of the Company's historical net salvage data except that most of the Company's plant property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

The total end of life net salvage amount must be incorporated in the development of annual depreciation rates to enable the Company to fully recover its total plant life costs. Otherwise, upon retirement of the plant, the Company will incur end of life costs without having recovered those plant related costs from the customers who benefitted from the use of the expired plant.

With regard to location type properties (e.g. generation facilities, etc.) a company will routinely experience both interim and terminal net salvage. Interim net salvage occurs in conjunction with interim retirements that occur throughout the life of the asset group. This net salvage activity (routinely and largely cost of removal) is attributable to the removal of components within the Company's facilities to enable the placement of a new asset component. Interim net salvage is routinely negative given the care required in removing the defective component so as not to damage the remaining plant in service. Interim net salvage is applicable to the estimated interim retirement assets.

The terminal net salvage component is attributable to the end of life costs incurred (less any gross salvage received) to disconnect, remove, demolish and/or dispose of the operating asset. Terminal net salvage is attributable to those assets remaining in service subsequent to the occurrence of interim retirements.

The total net salvage incorporated into the depreciation rate for location type plant account investments is the sum of interim and terminal net salvage. Both of the items must be incorporated in the development of annual depreciation rates to enable the Company to fully recover its total plant life costs. Otherwise, upon retirement of the plant, the Company will incur end of life costs without having recovered those plant related costs from the customers who benefitted from the use of the expired facility.

<u>Service Lives</u>

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

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

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

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family of curves are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Furthermore, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgment Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company retirement experience to develop a survivor curve (Observed Life Table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least squares technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each proceeding year's original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes a Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If, in the past, the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date.

Judgment Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgment are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgment alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what is considered to be a reasonable life for this plant giving consideration to the current age and use of the facilities.

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

Study Analysis & Results

ACCOUNT – 390.00 Structures And Improvements

Historical Experience

Plant Statistics
Plant Balance = $26,865,571
Average Age of Survivors = 14.7 years.
Original Gross Additions = $34,468,087
Oldest Surviving Vintage = 1952
Retirements - $7,211,961, or 20.9% of historical additions.
Average Age of Retirements = 16.7 years

Experience Bands 1977 – 2008 (Full Depth) 35-R1

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
66%	94%	82%	17%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
68%	70%	102%	105%

Forecasted Net Salvage: 73%

Plant Considerations/Future Expectations

This investment is related to cost of various General related structures and improvements. Ongoing changes occur due to required component upgrades as well as changes in business environment conditions.

Life Analysis Method: Retirement Rate Method (Actuarial)

Current Depreciation Parameters

ASL/Curve: 35-R3
Net Salv: -10%

Proposed Depreciation Parameters

ASL/Curve: 35-R1
Future Net Salv: 0%

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	2.25%	2.93%
Average Remaining Life	25.2 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 392.10 Transportation Equipment - Trailers

Historical Experience

Plant Statistics
Plant Balance = $113,614
Average Age of Survivors = 20.1 years.
Original Gross Additions = $423,678
Oldest Surviving Vintage = 19
Retirements - $206,244, or 48.7% of historical additions.
Average Age of Retirements = 11.0 years

Experience Bands 1977 – 2008 (Full Depth) 24-L1

Historic Net Salvage: (71-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1971-2008
24%	23%	29%	50%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
21%	15%	26%	34%

Forecasted Net Salvage: 34%

Plant Considerations/Future Expectations

This property group contains investments principally related to trailers used by the Company's workforce. The minor investment in this property account is currently fully depreciated, therefore, no further accruals should be recorded until such time that significant additional plant is added and/or the fully accrued status is significantly reduced.*The proposed depreciation is currently set to zero percent.

Life Analysis Method: Retirement Rate Method (Actuarial)

Current Depreciation Parameters

ASL/Curve: 20-L2
Net Salv: 0%

Proposed Depreciation Parameters

ASL/Curve: 24-L1
Future Net Salv: 20%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	0.00% *	0.00%
Average Remaining Life	12.6 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 392.20 Transportation Equipment – Cars & Trucks

Historical Experience

Plant Statistics	Plant Balance = $19,932,792 Average Age of Survivors = 5.3 years. Original Gross Additions = $19,932,792 Oldest Surviving Vintage = 1987 Retirements - $14,211,853, or 71.3% of historical additions. Average Age of Retirements = 8.9 years
Experience Bands	1977 – 2008 (Full Depth) 8-R2

Historic Net Salvage: (68-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	1968-2008
21%	22%	24%	24%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
29%	24%	24%	23%

Forecasted Net Salvage: 23%

Plant Considerations/Future Expectations

This property group contains investments is related to vehicles which are used in constructing and maintaining distribution and transmission lines. The Company's general replacement policy is 8 years or 95,000 miles.

Life Analysis Method: Retirement Rate Method (Actuarial)

Current Depreciation Parameters

ASL/Curve: 7-R3
Net Salv: 20%

Proposed Depreciation Parameters

ASL/Curve: 8-R2
Future Net Salv: 20%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	4.70%	13.33%
Average Remaining Life	4.5 years	N/A

(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

ACCOUNT – 396.20 Power Operated Equipment

Historical Experience

Plant Statistics
Plant Balance = $53,432
Average Age of Survivors = 6.7 years.
Original Gross Additions = $215.171
Oldest Surviving Vintage = 1992
Retirements - $20,275, or 9.4% of historical additions.
Average Age of Retirements = 4.5 years

Experience Bands Estimated 10-R2

Historic Net Salvage: (01-08)

Three Year Average Net Salvage Percent			Full Depth
2004-06	2005-07	2006-08	2001-2008
56%	0%	0%	54%

Gross Salvage Trend Analysis

20 Year	15 Year	10 Year	5 Year
36%	36%	36%	0%

Forecasted Net Salvage: 0%

Plant Considerations/Future Expectations

The investment in this account is related to power operated equipment used by the Company's workforce.

Life Analysis Method: Retirement Rate Method (Actuarial)

Current Depreciation Parameters

ASL/Curve: 10-R2
Net Salv: 40%

Proposed Depreciation Parameters

ASL/Curve: 10-R2
Future Net Salv: 50%

	New Rate @New Parameters	Old Rate @ Old Parameters
Rate	7.58%	2.69%
Average Remaining Life	4.7 years	N/A

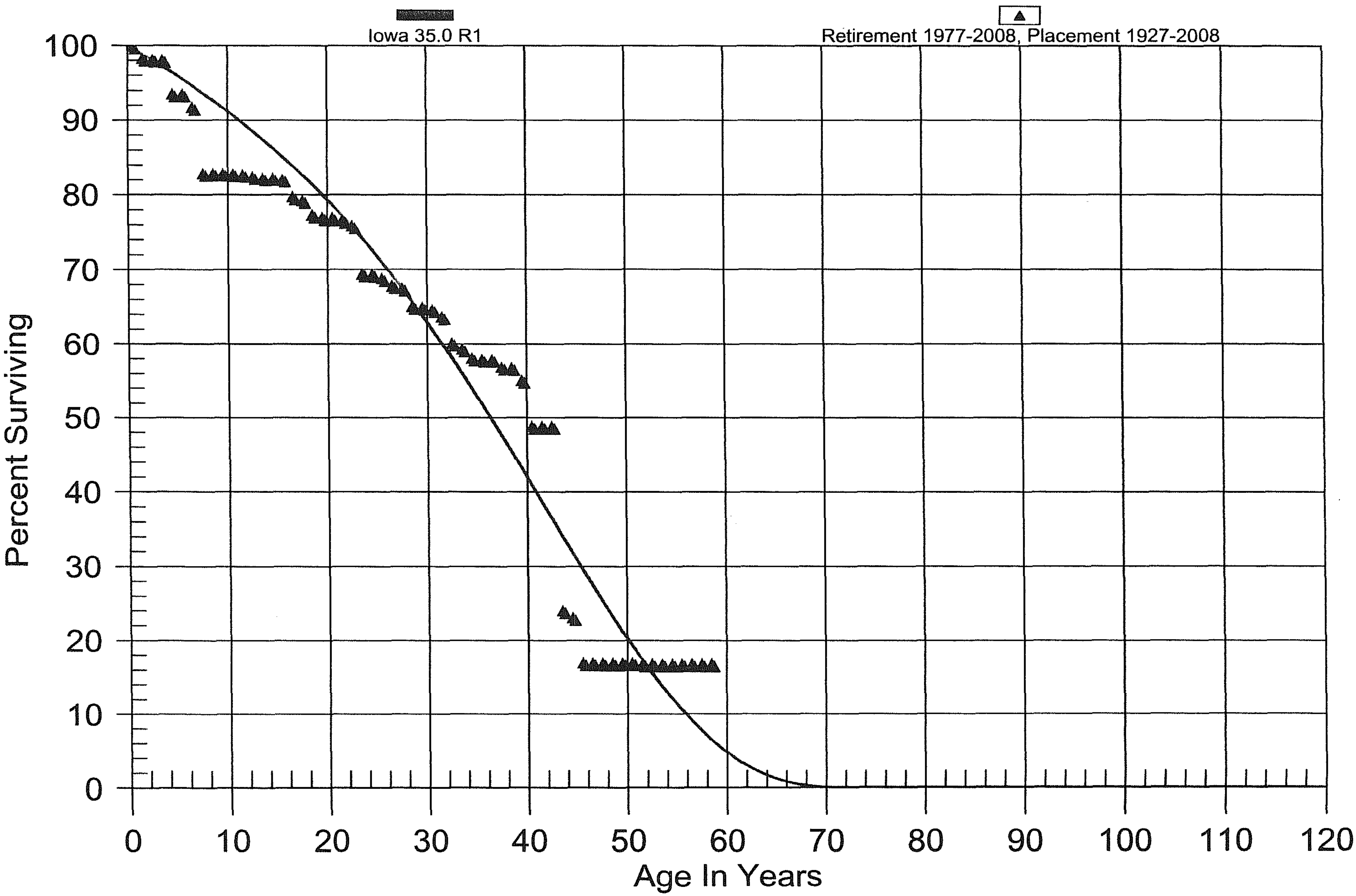
(ASL – Average Service Life; NS – Net Salvage; FTA – Fit to Age; N/A—Not Available, Not Applicable

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	$30,923,553.10	$25,673.53	0.00083	100.00
0.5 - 1.5	$30,647,167.91	$502,495.67	0.01640	99.92
1.5 - 2.5	$25,441,191.03	$28,537.28	0.00112	98.28
2.5 - 3.5	$25,028,496.79	$21,067.24	0.00084	98.17
3.5 - 4.5	$21,558,077.99	$998,763.21	0.04633	98.09
4.5 - 5.5	$19,733,258.09	$3,328.20	0.00017	93.54
5.5 - 6.5	$19,488,426.81	$366,883.65	0.01883	93.53
6.5 - 7.5	$18,697,663.99	$1,803,312.79	0.09645	91.77
7.5 - 8.5	$16,707,188.43	$1,185.30	0.00007	82.91
8.5 - 9.5	$17,175,374.34	$201.39	0.00001	82.91
9.5 - 10.5	$17,190,014.78	$6,909.72	0.00040	82.91
10.5 - 11.5	$17,087,646.97	$22,460.50	0.00131	82.87
11.5 - 12.5	$16,449,372.68	$54,345.65	0.00330	82.77
12.5 - 13.5	$16,094,049.40	$35,258.34	0.00219	82.49
13.5 - 14.5	$14,825,001.39	$5,991.04	0.00040	82.31
14.5 - 15.5	$12,535,830.93	$23,427.31	0.00187	82.28
15.5 - 16.5	$12,213,329.10	$347,724.14	0.02847	82.12
16.5 - 17.5	$11,709,677.50	$76,946.11	0.00657	79.79
17.5 - 18.5	$11,563,442.33	$280,138.65	0.02423	79.26
18.5 - 19.5	$11,284,647.27	$49,274.84	0.00437	77.34
19.5 - 20.5	$11,221,468.22	$13,310.98	0.00119	77.00
20.5 - 21.5	$11,316,923.39	$45,061.83	0.00398	76.91
21.5 - 22.5	$11,648,884.15	$107,434.88	0.00922	76.61
22.5 - 23.5	$11,083,154.10	$941,681.64	0.08497	75.90
23.5 - 24.5	$9,634,763.28	$6,423.19	0.00067	69.45
24.5 - 25.5	$6,635,781.46	$51,633.39	0.00778	69.40
25.5 - 26.5	$6,090,655.43	$87,706.60	0.01440	68.86
26.5 - 27.5	$4,270,597.43	$20,932.77	0.00490	67.87
27.5 - 28.5	$4,063,964.67	$146,903.96	0.03615	67.54
28.5 - 29.5	$3,674,970.31	$3,871.72	0.00105	65.10
29.5 - 30.5	$3,152,344.74	$15,451.43	0.00490	65.03
30.5 - 31.5	$3,151,652.41	$48,328.18	0.01533	64.71
31.5 - 32.5	$2,803,070.86	$158,564.05	0.05657	63.72
32.5 - 33.5	$2,602,897.43	$33,240.37	0.01277	60.11
33.5 - 34.5	$2,604,500.26	$55,135.57	0.02117	59.35
34.5 - 35.5	$2,532,951.30	$7,220.80	0.00285	58.09
35.5 - 36.5	$2,438,990.71	$0.00	0.00000	57.93

Montana-Dakota Utilities Company

Common Plant

390.00 STRUCTURES & IMPROVEMENTS

Observed Life Table

Retirement Expr. 1977 TO 2008
Placement Years 1927 TO 2008

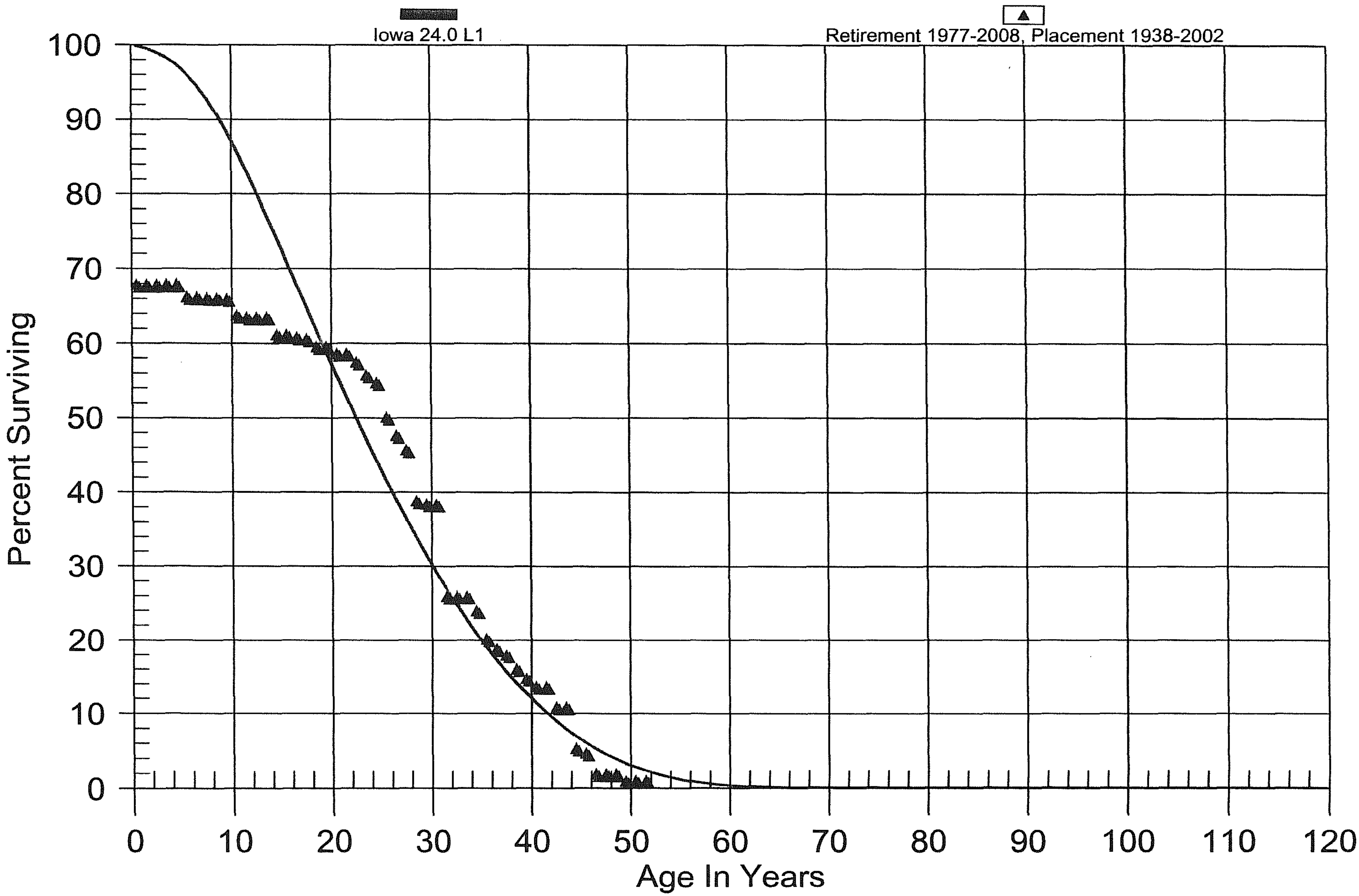
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$2,015,672.80	$35,668.14	0.01770	57.93
37.5 - 38.5	$1,961,785.03	$4,062.20	0.00207	56.90
38.5 - 39.5	$1,951,978.24	$58,309.83	0.02987	56.78
39.5 - 40.5	$1,852,190.63	$209,702.82	0.11322	55.09
40.5 - 41.5	$633,016.01	$0.00	0.00000	48.85
41.5 - 42.5	$471,963.84	$0.00	0.00000	48.85
42.5 - 43.5	$319,624.00	$162,495.28	0.50840	48.85
43.5 - 44.5	$153,278.41	$5,769.46	0.03764	24.01
44.5 - 45.5	$128,525.01	$33,976.68	0.26436	23.11
45.5 - 46.5	$89,090.20	$0.00	0.00000	17.00
46.5 - 47.5	$79,478.26	$0.00	0.00000	17.00
47.5 - 48.5	$78,245.67	$0.00	0.00000	17.00
48.5 - 49.5	$76,167.37	$0.00	0.00000	17.00
49.5 - 50.5	$377,333.98	$0.00	0.00000	17.00
50.5 - 51.5	$375,995.96	$3,171.15	0.00843	17.00
51.5 - 52.5	$361,606.23	$0.00	0.00000	16.86
52.5 - 53.5	$337,003.55	$400.00	0.00119	16.86
53.5 - 54.5	$318,189.48	$0.00	0.00000	16.84
54.5 - 55.5	$317,325.59	$0.00	0.00000	16.84
55.5 - 56.5	$313,830.63	$0.00	0.00000	16.84
56.5 - 57.5	$301,579.65	$0.00	0.00000	16.84
57.5 - 58.5	$301,579.65	$0.00	0.00000	16.84

Montana-Dakota Utilities Company

Common Plant

392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Original And Smooth Survivor Curves



Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Observed Life Table
Retirement Expr. 1977 TO 2008
Placement Years 1938 TO 2002

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	$356,443.75	$114,357.49	0.32083	100.00
0.5 - 1.5	$242,355.60	$0.00	0.00000	67.92
1.5 - 2.5	$244,319.67	$0.00	0.00000	67.92
2.5 - 3.5	$248,158.07	$0.00	0.00000	67.92
3.5 - 4.5	$252,953.29	$0.00	0.00000	67.92
4.5 - 5.5	$255,850.66	$6,163.53	0.02409	67.92
5.5 - 6.5	$252,411.39	$0.00	0.00000	66.28
6.5 - 7.5	$255,665.70	$386.34	0.00151	66.28
7.5 - 8.5	$253,055.36	$0.00	0.00000	66.18
8.5 - 9.5	$263,786.40	$725.94	0.00275	66.18
9.5 - 10.5	$251,634.92	$8,265.96	0.03285	66.00
10.5 - 11.5	$244,523.84	$948.01	0.00388	63.83
11.5 - 12.5	$243,846.66	$0.00	0.00000	63.58
12.5 - 13.5	$245,341.96	$0.00	0.00000	63.58
13.5 - 14.5	$242,935.73	$8,939.16	0.03680	63.58
14.5 - 15.5	$220,136.89	$0.00	0.00000	61.24
15.5 - 16.5	$205,890.32	$1,156.30	0.00562	61.24
16.5 - 17.5	$194,616.78	$717.60	0.00369	60.90
17.5 - 18.5	$157,686.55	$2,766.18	0.01754	60.68
18.5 - 19.5	$144,905.34	$10.00	0.00007	59.61
19.5 - 20.5	$126,605.23	$1,934.11	0.01528	59.61
20.5 - 21.5	$113,719.62	$0.00	0.00000	58.70
21.5 - 22.5	$108,939.25	$2,178.80	0.02000	58.70
22.5 - 23.5	$112,230.42	$3,353.83	0.02988	57.52
23.5 - 24.5	$112,393.82	$2,052.44	0.01826	55.80
24.5 - 25.5	$97,996.97	$8,264.54	0.08433	54.78
25.5 - 26.5	$84,679.95	$4,241.96	0.05009	50.16
26.5 - 27.5	$67,895.83	$2,723.07	0.04011	47.65
27.5 - 28.5	$60,335.69	$9,044.01	0.14989	45.74
28.5 - 29.5	$48,414.31	$561.49	0.01160	38.88
29.5 - 30.5	$42,220.99	$27.29	0.00065	38.43
30.5 - 31.5	$42,436.42	$13,769.43	0.32447	38.41
31.5 - 32.5	$28,666.99	$0.00	0.00000	25.95
32.5 - 33.5	$27,748.88	$0.00	0.00000	25.95
33.5 - 34.5	$26,433.58	$1,990.55	0.07530	25.95
34.5 - 35.5	$23,767.15	$3,768.07	0.15854	23.99
35.5 - 36.5	$17,503.42	$1,141.64	0.06522	20.19

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Observed Life Table

Retirement Expr. 1977 TO 2008
Placement Years 1938 TO 2002

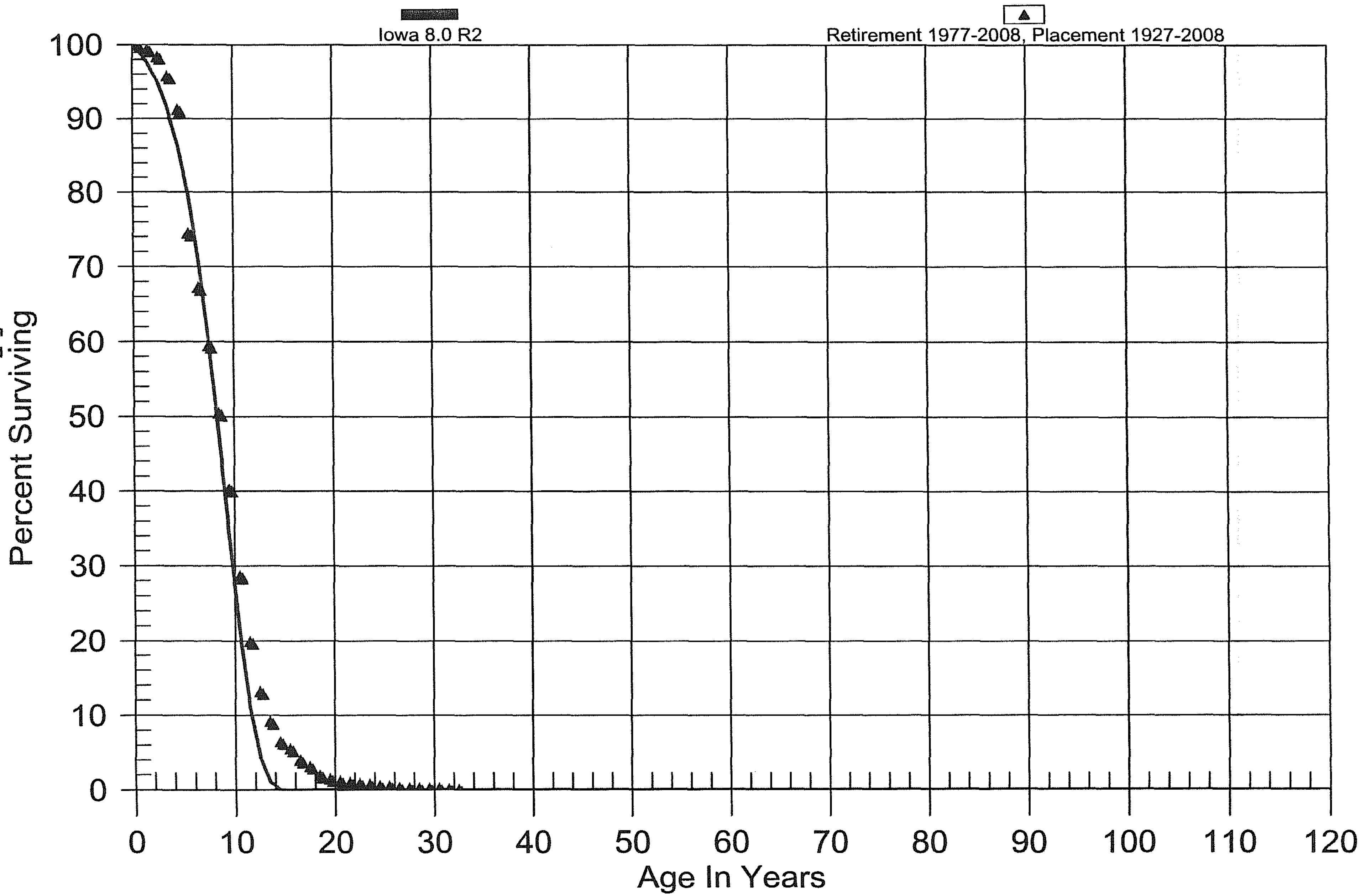
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$13,865.98	$616.19	0.04444	18.87
37.5 - 38.5	$12,448.24	$1,318.81	0.10594	18.03
38.5 - 39.5	$8,563.34	$702.41	0.08203	16.12
39.5 - 40.5	$6,359.93	$478.15	0.07518	14.80
40.5 - 41.5	$5,881.78	$0.00	0.00000	13.69
41.5 - 42.5	$5,881.78	$1,174.62	0.19970	13.69
42.5 - 43.5	$3,285.93	$0.00	0.00000	10.95
43.5 - 44.5	$2,776.32	$1,412.40	0.50873	10.95
44.5 - 45.5	$1,243.70	$156.18	0.12558	5.38
45.5 - 46.5	$897.09	$518.00	0.57742	4.71
46.5 - 47.5	$379.09	$0.00	0.00000	1.99
47.5 - 48.5	$379.09	$0.00	0.00000	1.99
48.5 - 49.5	$379.09	$181.56	0.47894	1.99
49.5 - 50.5	$197.53	$0.00	0.00000	1.04
50.5 - 51.5	$197.53	$0.00	0.00000	1.04

Montana-Dakota Utilities Company

Common Plant

392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Original And Smooth Survivor Curves



Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)
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	$16,263,220.70	$5,499.26	0.00034	100.00
0.5 - 1.5	$16,348,847.53	$87,168.33	0.00533	99.97
1.5 - 2.5	$15,431,075.03	$166,366.41	0.01078	99.43
2.5 - 3.5	$15,006,973.54	$386,309.51	0.02574	98.36
3.5 - 4.5	$14,885,524.57	$702,446.40	0.04719	95.83
4.5 - 5.5	$13,920,444.75	$2,558,487.11	0.18379	91.31
5.5 - 6.5	$11,287,538.90	$1,099,563.88	0.09741	74.53
6.5 - 7.5	$9,971,483.08	$1,142,230.76	0.11455	67.27
7.5 - 8.5	$8,688,053.52	$1,320,355.14	0.15197	59.56
8.5 - 9.5	$7,180,925.02	$1,445,506.47	0.20130	50.51
9.5 - 10.5	$5,578,144.77	$1,611,854.62	0.28896	40.34
10.5 - 11.5	$3,951,413.61	$1,200,914.21	0.30392	28.68
11.5 - 12.5	$2,653,435.46	$902,123.73	0.33998	19.97
12.5 - 13.5	$1,793,239.23	$538,952.21	0.30055	13.18
13.5 - 14.5	$1,258,149.76	$372,419.93	0.29601	9.22
14.5 - 15.5	$897,597.56	$125,610.85	0.13994	6.49
15.5 - 16.5	$693,491.50	$191,649.93	0.27636	5.58
16.5 - 17.5	$512,533.35	$110,231.79	0.21507	4.04
17.5 - 18.5	$238,220.35	$89,693.67	0.37652	3.17
18.5 - 19.5	$145,088.66	$36,484.08	0.25146	1.98
19.5 - 20.5	$96,293.51	$18,022.65	0.18716	1.48
20.5 - 21.5	$79,032.74	$14,314.28	0.18112	1.20
21.5 - 22.5	$66,894.60	$8,221.53	0.12290	0.98
22.5 - 23.5	$67,961.80	$11,993.79	0.17648	0.86
23.5 - 24.5	$55,968.01	$15,281.05	0.27303	0.71
24.5 - 25.5	$40,686.96	$6,649.66	0.16343	0.52
25.5 - 26.5	$34,037.30	$9,504.10	0.27923	0.43
26.5 - 27.5	$24,533.20	$7,511.40	0.30617	0.31
27.5 - 28.5	$17,021.80	$0.00	0.00000	0.22
28.5 - 29.5	$17,021.80	$3,358.54	0.19731	0.22
29.5 - 30.5	$13,663.26	$0.00	0.00000	0.17
30.5 - 31.5	$13,663.26	$9,288.73	0.67983	0.17
31.5 - 32.5	$4,374.53	$3,254.32	0.74392	0.06

Montana-Dakota Utilities Company

Common Plant

390.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2008

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R1*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1952	12,250.98	35.00	350.02	4.38	1,533.29
1953	3,494.96	35.00	99.85	4.70	469.42
1954	863.89	35.00	24.68	5.02	124.01
1955	18,414.07	35.00	526.10	5.35	2,817.23
1956	24,602.68	35.00	702.91	5.69	4,001.24
1957	11,218.58	35.00	320.52	6.04	1,934.95
1958	1,338.02	35.00	38.23	6.39	244.22
1959	413.04	35.00	11.80	6.75	79.63
1960	2,078.30	35.00	59.38	7.11	422.45
1961	1,232.59	35.00	35.22	7.49	263.69
1962	9,611.94	35.00	274.62	7.87	2,160.94
1963	5,458.13	35.00	155.94	8.26	1,287.74
1964	18,983.94	35.00	542.38	8.65	4,694.21
1965	3,850.31	35.00	110.01	9.06	996.64
1966	152,339.84	35.00	4,352.43	9.47	41,232.40
1967	161,052.17	35.00	4,601.35	9.90	45,531.99
1968	1,009,471.80	35.00	28,841.17	10.33	297,810.33
1969	74,566.26	35.00	2,130.40	10.77	22,934.31
1970	5,744.59	35.00	164.13	11.21	1,840.46
1971	18,619.63	35.00	531.97	11.67	6,208.80
1972	423,317.91	35.00	12,094.43	12.14	146,804.23
1973	75,575.41	35.00	2,159.23	12.61	27,237.70
1974	16,413.39	35.00	468.94	13.10	6,143.12
1976	41,609.38	35.00	1,188.80	14.10	16,763.85
1977	300,253.37	35.00	8,578.41	14.62	125,390.21
1978	8,332.24	35.00	238.06	15.14	3,604.75
1979	528,255.41	35.00	15,092.55	15.68	236,618.69

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R1*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1980	243,249.46	35.00	6,949.77	16.22	112,747.85
1981	186,300.70	35.00	5,322.71	16.78	89,304.05
1982	1,752,465.62	35.00	50,068.92	17.34	868,363.59
1983	494,701.29	35.00	14,133.89	17.92	253,259.33
1984	3,123,696.11	35.00	89,245.74	18.50	1,651,350.17
1985	538,049.67	35.00	15,372.38	19.10	293,576.29
1986	465,886.01	35.00	13,310.62	19.70	262,233.62
1988	4,844.35	35.00	138.41	20.93	2,897.34
1989	26,601.63	35.00	760.02	21.56	16,388.46
1990	3,459.76	35.00	98.85	22.20	2,194.44
1991	70,702.10	35.00	2,020.00	22.84	46,146.64
1992	163,560.50	35.00	4,673.01	23.50	109,798.78
1993	301,888.43	35.00	8,625.12	24.15	208,333.09
1994	2,292,791.36	35.00	65,506.33	24.82	1,625,737.03
1995	1,242,406.73	35.00	35,496.25	25.49	904,684.44
1996	328,408.43	35.00	9,382.81	26.16	245,465.52
1997	650,004.48	35.00	18,570.99	26.84	498,449.30
1998	261,211.63	35.00	7,462.96	27.52	205,407.21
1999	261,325.27	35.00	7,466.21	28.21	210,630.00
2000	720,315.20	35.00	20,579.81	28.90	594,818.76
2001	267,033.58	35.00	7,629.30	29.60	225,824.35
2002	433,470.02	35.00	12,384.48	30.30	375,258.43
2003	267,482.71	35.00	7,642.13	31.01	236,964.59
2004	1,262,380.59	35.00	36,066.92	31.72	1,144,047.68
2005	3,529,351.33	35.00	100,835.54	32.44	3,270,942.84
2006	43,081.84	35.00	1,230.87	33.16	40,819.00
2007	4,703,481.21	35.00	134,381.08	33.89	4,554,604.15

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 35 *Survivor Curve: R1*

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
2008	298,058.63	35.00	8,515.70	34.63	294,900.52
Total	26,865,571.47	35.00	767,564.36	25.20	19,344,297.98

Composite Average Remaining Life ... 25.2 Years

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 24 *Survivor Curve: L1*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1963	190.43	24.00	7.93	5.69	45.18
1964	120.22	24.00	5.01	5.91	29.59
1965	216.05	24.00	9.00	6.13	55.14
1966	700.52	24.00	29.19	6.35	185.28
1969	249.14	24.00	10.38	7.04	73.04
1971	228.46	24.00	9.52	7.51	71.52
1973	286.33	24.00	11.93	8.01	95.54
1974	675.88	24.00	28.16	8.26	232.68
1975	1,315.30	24.00	54.80	8.52	467.00
1976	269.34	24.00	11.22	8.78	98.58
1978	863.28	24.00	35.97	9.33	335.47
1979	5,829.36	24.00	242.87	9.61	2,333.05
1980	214.61	24.00	8.94	9.89	88.44
1981	1,222.60	24.00	50.94	10.18	518.60
1982	2,519.67	24.00	104.98	10.48	1,099.82
1983	653.10	24.00	27.21	10.78	293.30
1984	13,420.97	24.00	559.17	11.09	6,199.77
1987	910.82	24.00	37.95	12.05	457.41
1988	13,891.67	24.00	578.78	12.39	7,170.63
1989	19,014.78	24.00	792.23	12.73	10,087.28
1990	2,233.43	24.00	93.05	13.08	1,217.52
1991	26,255.64	24.00	1,093.91	13.44	14,705.87
1992	6,257.81	24.00	260.72	13.81	3,600.85
1993	6,531.90	24.00	272.14	14.19	3,860.92
1994	403.98	24.00	16.83	14.57	245.26
1995	2,752.84	24.00	114.69	14.97	1,716.64
1997	359.93	24.00	15.00	15.82	237.24

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 24 *Survivor Curve: L1*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2001	6,026.26	24.00	251.08	17.97	4,512.45
Total	113,614.32	24.00	4,733.60	12.68	60,034.05

Composite Average Remaining Life ... 12.6 Years

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 8 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1987	360.89	0.00	0.00	0.00	0.00
1988	761.50	0.00	0.00	0.00	0.00
1989	12,311.07	0.00	0.00	0.00	0.00
1990	9,081.62	0.00	0.00	0.00	0.00
1991	147,448.78	0.00	0.00	0.00	0.00
1992	24,702.24	0.00	0.00	0.00	0.00
1993	109,061.69	0.00	0.00	0.00	0.00
1994	3,734.47	8.00	466.74	0.50	233.37
1995	4,977.50	8.00	622.10	0.52	325.14
1997	129,288.10	8.00	16,158.77	1.00	16,095.53
1998	88,234.73	8.00	11,027.81	1.28	14,150.68
1999	214,078.24	8.00	26,756.06	1.61	43,178.01
2000	357,825.85	8.00	44,722.01	2.01	89,797.96
2001	338,098.40	8.00	42,256.42	2.48	104,647.79
2002	611,564.36	8.00	76,434.91	3.02	230,929.28
2003	442,388.14	8.00	55,290.83	3.64	201,112.07
2004	559,521.89	8.00	69,930.51	4.32	301,987.36
2005	211,753.79	8.00	26,465.54	5.06	133,822.17
2006	793,562.01	8.00	99,181.46	5.85	579,759.83
2007	927,917.46	8.00	115,973.55	6.68	774,581.13
2008	339,959.69	8.00	42,489.05	7.55	320,865.91
Total	5,326,632.42	5.33	627,775.77	4.48	2,811,486.23

Composite Average Remaining Life ... 4.48 Years

Montana-Dakota Utilities Company
Common Plant
396.20 POWER OPERATED EQUIPMENT
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2008
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **10** *Survivor Curve:* **R2**

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1992	981.61	10.00	98.15	0.66	64.84
2000	344.94	10.00	34.49	3.56	122.68
2001	590.20	10.00	59.01	4.15	244.72
2002	51,515.72	10.00	5,151.10	4.79	24,678.71
Total	53,432.47	10.00	5,342.76	4.70	25,110.95

Composite Average Remaining Life ... 4.70 Years

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	4,755.66	662.00	13.92%	40.08	0.84%	621.92	13.08%
1969	23,146.27	350.00	1.51%	978.69	4.23%	(628.69)	-2.72%
1970	9,535.95	5,550.94	58.21%	1,401.83	14.70%	4,149.11	43.51%
1971	55.50	816.00	1470.27%	1,457.69	2626.47%	(641.69)	-1156.20%
1972	89,020.14	20,850.79	23.42%	100.23	0.11%	20,750.56	23.31%
1973	823.15	556.00	67.55%	0.00	0.00%	556.00	67.55%
1974	6,649.36	0.00	0.00%	2,380.69	35.80%	(2,380.69)	-35.80%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	698.69	0.00	0.00%	17.84	2.55%	(17.84)	-2.55%
1977	33,563.08	10.00	0.03%	7,368.10	21.95%	(7,358.10)	-21.92%
1978	5,945.18	166.75	2.80%	470.81	7.92%	(304.06)	-5.11%
1979	361.83	-2.15	-0.59%	28.73	7.94%	(30.88)	-8.53%
1980	36,428.79	46,043.00	126.39%	0.00	0.00%	46,043.00	126.39%
1981	386.16	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	2,390.36	-35,198.49	-1472.52%	0.00	0.00%	(35,198.49)	-1472.52%
1983	151,268.18	52,055.19	34.41%	17,106.40	11.31%	34,948.79	23.10%
1984	0.00	239.87	0.00%	0.00	0.00%	239.87	0.00%
1985	29,321.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1986	353,205.79	462.87	0.13%	23,017.27	6.52%	(22,554.40)	-6.39%
1987	114,668.89	6.60	0.01%	178,550.90	155.71%	(178,544.30)	-155.70%
1988	1,065.81	20.00	1.88%	44,427.72	4168.45%	(44,407.72)	-4166.57%
1989	2,907.81	0.00	0.00%	1,361.75	46.83%	(1,361.75)	-46.83%
1990	1,179.28	0.00	0.00%	4,183.53	354.75%	(4,183.53)	-354.75%
1991	11,317.67	0.00	0.00%	21,000.00	185.55%	(21,000.00)	-185.55%
1992	6,400.00	0.00	0.00%	59,485.65	929.46%	(59,485.65)	-929.46%
1993	66,938.07	5,500.00	8.22%	11,015.00	16.46%	(5,515.00)	-8.24%
1994	76,339.95	52.50	0.07%	3,348.28	4.39%	(3,295.78)	-4.32%
1995	249,269.07	188,096.00	75.46%	48,516.38	19.46%	139,579.62	56.00%

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1996	174,572.37	26,753.21	15.32%	22,545.80	12.91%	4,207.41	2.41%
1997	97,788.56	45,363.50	46.39%	4,264.75	4.36%	41,098.75	42.03%
1998	255,811.74	0.00	0.00%	40,398.90	15.79%	(40,398.90)	-15.79%
1999	303,792.23	30,685.00	10.10%	12,226.33	4.02%	18,458.67	6.08%
2000	172,070.45	10,283.75	5.98%	30,934.95	17.98%	(20,651.20)	-12.00%
2001	109,759.98	0.00	0.00%	14,718.75	13.41%	(14,718.75)	-13.41%
2002	110,036.20	0.00	0.00%	29,201.73	26.54%	(29,201.73)	-26.54%
2003	16,416.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	1,053,662.14	639,099.00	60.66%	26,474.19	2.51%	612,624.81	58.14%
2005	-32,272.79	0.00	0.00%	225.00	0.00%	(225.00)	0.00%
2006	381,881.81	330,000.00	86.41%	9,972.50	2.61%	320,027.50	83.80%
2007	95,847.37	111,000.00	115.81%	14,204.68	14.82%	96,795.32	100.99%
2008	26,948.70	0.00	0.00%	2,070.30	7.68%	(2,070.30)	-7.68%

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1968 - 1970	37,437.88	6,562.94	17.53%	2,420.60	6.47%	4,142.34	11.06%
1969 - 1971	32,737.72	6,716.94	20.52%	3,838.21	11.72%	2,878.73	8.79%
1970 - 1972	98,611.59	27,217.73	27.60%	2,959.75	3.00%	24,257.98	24.60%
1971 - 1973	89,898.79	22,222.79	24.72%	1,557.92	1.73%	20,664.87	22.99%
1972 - 1974	96,492.65	21,406.79	22.18%	2,480.92	2.57%	18,925.87	19.61%
1973 - 1975	7,472.51	556.00	7.44%	2,380.69	31.86%	(1,824.69)	-24.42%
1974 - 1976	7,348.05	0.00	0.00%	2,398.53	32.64%	(2,398.53)	-32.64%
1975 - 1977	34,261.77	10.00	0.03%	7,385.94	21.56%	(7,375.94)	-21.53%
1976 - 1978	40,206.95	176.75	0.44%	7,856.75	19.54%	(7,680.00)	-19.10%
1977 - 1979	39,870.09	174.60	0.44%	7,867.64	19.73%	(7,693.04)	-19.30%
1978 - 1980	42,735.80	46,207.60	108.12%	499.54	1.17%	45,708.06	106.95%
1979 - 1981	37,176.78	46,040.85	123.84%	28.73	0.08%	46,012.12	123.77%
1980 - 1982	39,205.31	10,844.51	27.66%	0.00	0.00%	10,844.51	27.66%
1981 - 1983	154,044.70	16,856.70	10.94%	17,106.40	11.10%	(249.70)	-0.16%
1982 - 1984	153,658.54	17,096.57	11.13%	17,106.40	11.13%	(9.83)	-0.01%
1983 - 1985	180,589.18	52,295.06	28.96%	17,106.40	9.47%	35,188.66	19.49%
1984 - 1986	382,526.79	702.74	0.18%	23,017.27	6.02%	(22,314.53)	-5.83%
1985 - 1987	497,195.68	469.47	0.09%	201,568.17	40.54%	(201,098.70)	-40.45%
1986 - 1988	468,940.49	489.47	0.10%	245,995.89	52.46%	(245,506.42)	-52.35%
1987 - 1989	118,642.51	26.60	0.02%	224,340.37	189.09%	(224,313.77)	-189.07%
1988 - 1990	5,152.90	20.00	0.39%	49,973.00	969.80%	(49,953.00)	-969.42%
1989 - 1991	15,404.76	0.00	0.00%	26,545.28	172.32%	(26,545.28)	-172.32%
1990 - 1992	18,896.95	0.00	0.00%	84,669.18	448.06%	(84,669.18)	-448.06%
1991 - 1993	84,655.74	5,500.00	6.50%	91,500.65	108.09%	(86,000.65)	-101.59%
1992 - 1994	149,678.02	5,552.50	3.71%	73,848.93	49.34%	(68,296.43)	-45.63%
1993 - 1995	392,547.09	193,648.50	49.33%	62,879.66	16.02%	130,768.84	33.31%
1994 - 1996	500,181.39	214,901.71	42.96%	74,410.46	14.88%	140,491.25	28.09%
1995 - 1997	521,630.00	260,212.71	49.88%	75,326.93	14.44%	184,885.78	35.44%

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1996 - 1998	528,172.67	72,116.71	13.65%	67,209.45	12.72%	4,907.26	0.93%
1997 - 1999	657,392.53	76,048.50	11.57%	56,889.98	8.65%	19,158.52	2.91%
1998 - 2000	731,674.42	40,968.75	5.60%	83,560.18	11.42%	(42,591.43)	-5.82%
1999 - 2001	585,622.66	40,968.75	7.00%	57,880.03	9.88%	(16,911.28)	-2.89%
2000 - 2002	391,866.63	10,283.75	2.62%	74,855.43	19.10%	(64,571.68)	-16.48%
2001 - 2003	236,212.18	0.00	0.00%	43,920.48	18.59%	(43,920.48)	-18.59%
2002 - 2004	1,180,114.34	639,099.00	54.16%	55,675.92	4.72%	583,423.08	49.44%
2003 - 2005	1,037,805.35	639,099.00	61.58%	26,699.19	2.57%	612,399.81	59.01%
2004 - 2006	1,403,271.16	969,099.00	69.06%	36,671.69	2.61%	932,427.31	66.45%
2005 - 2007	445,456.39	441,000.00	99.00%	24,402.18	5.48%	416,597.82	93.52%
2006 - 2008	504,677.88	441,000.00	87.38%	26,247.48	5.20%	414,752.52	82.18%

Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1968 - 2008	4,043,956.40	1,479,422.33	36.58	633,495.45	15.67	845,926.88	20.92

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	35.0
Average Retirement Age (Yrs)	8.4
Years To ASL	26.6
Inflation Factor At 2.75% to ASL	2.06

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	67.87%
1994-2008	**15 - Year Trend**	70.21%
1999-2008	**10 - Year Trend**	102.38%
2004-2008	**5 - Year Trend**	105.40%

Forcasted

Gross Salvage 105.40%
(Five Year Trend)

Cost Of Removal 32.22%

Net Salvage 73.18%

Montana-Dakota Utilities Company
Common Plant
391.30 COMPUTER EQUIPMENT - PC

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1992 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1992	16,323.58	218.76	1.34%	0.00	0.00%	218.76	1.34%
1993	24,638.45	1,093.74	4.44%	0.00	0.00%	1,093.74	4.44%
1994	71,970.57	3,693.70	5.13%	0.00	0.00%	3,693.70	5.13%
1995	101,939.34	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	24,221.86	0.00	0.00%	0.00	0.00%	0.00	0.00%
1997	26,853.75	2,585.00	9.63%	0.00	0.00%	2,585.00	9.63%
1998	390,103.65	5,604.45	1.44%	0.00	0.00%	5,604.45	1.44%
1999	435,616.00	2,250.00	0.52%	0.00	0.00%	2,250.00	0.52%
2000	154,278.59	250.00	0.16%	0.00	0.00%	250.00	0.16%
2001	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002	444,820.83	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	650,072.78	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	394,974.39	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	670,290.52	4,502.00	0.67%	0.00	0.00%	4,502.00	0.67%
2006	666,529.90	104,988.09	15.75%	0.00	0.00%	104,988.09	15.75%
2007	253,197.24	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	2,218,537.77	642.04	0.03%	0.00	0.00%	642.04	0.03%

Montana-Dakota Utilities Company
Common Plant
391.30 COMPUTER EQUIPMENT - PC

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1992 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1992 - 1994	112,932.60	5,006.20	4.43%	0.00	0.00%	5,006.20	4.43%
1993 - 1995	198,548.36	4,787.44	2.41%	0.00	0.00%	4,787.44	2.41%
1994 - 1996	198,131.77	3,693.70	1.86%	0.00	0.00%	3,693.70	1.86%
1995 - 1997	153,014.95	2,585.00	1.69%	0.00	0.00%	2,585.00	1.69%
1996 - 1998	441,179.26	8,189.45	1.86%	0.00	0.00%	8,189.45	1.86%
1997 - 1999	852,573.40	10,439.45	1.22%	0.00	0.00%	10,439.45	1.22%
1998 - 2000	979,998.24	8,104.45	0.83%	0.00	0.00%	8,104.45	0.83%
1999 - 2001	589,894.59	2,500.00	0.42%	0.00	0.00%	2,500.00	0.42%
2000 - 2002	599,099.42	250.00	0.04%	0.00	0.00%	250.00	0.04%
2001 - 2003	1,094,893.61	0.00	0.00%	0.00	0.00%	0.00	0.00%
2002 - 2004	1,489,868.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003 - 2005	1,715,337.69	4,502.00	0.26%	0.00	0.00%	4,502.00	0.26%
2004 - 2006	1,731,794.81	109,490.09	6.32%	0.00	0.00%	109,490.09	6.32%
2005 - 2007	1,590,017.66	109,490.09	6.89%	0.00	0.00%	109,490.09	6.89%
2006 - 2008	3,138,264.91	105,630.13	3.37%	0.00	0.00%	105,630.13	3.37%

Montana-Dakota Utilities Company
Common Plant
391.30 COMPUTER EQUIPMENT - PC

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1992 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1992 - 2008	6,544,369.22	125,827.78	1.92	0.00	0.00	125,827.78	1.92

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	28.0
Average Retirement Age (Yrs)	3.4
Years To ASL	24.6
Inflation Factor At 2.75% to ASL	1.95

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	2.12%
1994-2008	**15 - Year Trend**	2.88%
1999-2008	**10 - Year Trend**	5.00%
2004-2008	**5 - Year Trend**	7.37%

Forcasted

Gross Salvage (Five Year Trend)	7.37%
Cost Of Removal	0.00%
Net Salvage	7.37%

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1971 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1971	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1972	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1976	2,704.53	1,212.98	44.85%	0.00	0.00%	1,212.98	44.85%
1977	1,185.10	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978	412.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1983	3,422.98	732.00	21.38%	0.00	0.00%	732.00	21.38%
1984	7,618.25	2,000.00	26.25%	0.00	0.00%	2,000.00	26.25%
1985	118,612.65	4,547.20	3.83%	0.00	0.00%	4,547.20	3.83%
1986	661.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1987	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1988	0.00	30.12	0.00%	0.00	0.00%	30.12	0.00%
1989	1,569.70	400.00	25.48%	0.00	0.00%	400.00	25.48%
1990	1,141.64	0.00	0.00%	5.92	0.52%	(5.92)	-0.52%
1991	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1992	3,394.18	1,817.50	53.55%	0.00	0.00%	1,817.50	53.55%
1993	10.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1994	2,004.82	345.00	17.21%	0.00	0.00%	345.00	17.21%
1995	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1996	15,692.74	9,858.08	62.82%	356.00	2.27%	9,502.08	60.55%
1997	1,174.62	54.30	4.62%	0.00	0.00%	54.30	4.62%
1998	1,161.61	39.95	3.44%	0.00	0.00%	39.95	3.44%

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1971 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
1999	8,701.98	1,450.00	16.66%	0.00	0.00%	1,450.00	16.66%
2000	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001	181.56	275.00	151.47%	0.00	0.00%	275.00	151.47%
2002	1,666.61	298.65	17.92%	0.00	0.00%	298.65	17.92%
2003	2,052.44	25.00	1.22%	0.00	0.00%	25.00	1.22%
2004	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2005	14,523.90	3,500.00	24.10%	0.00	0.00%	3,500.00	24.10%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	4,477.25	950.00	21.22%	0.00	0.00%	950.00	21.22%
2008	15,588.19	4,850.00	31.11%	0.00	0.00%	4,850.00	31.11%

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1971 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1971 - 1973	246.00	71,707.06	29149.21%	149.91	60.94%	71,557.15	29088.27%
1972 - 1974	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1973 - 1975	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1974 - 1976	2,704.53	1,212.98	44.85%	0.00	0.00%	1,212.98	44.85%
1975 - 1977	3,889.63	1,212.98	31.18%	0.00	0.00%	1,212.98	31.18%
1976 - 1978	4,301.82	1,212.98	28.20%	0.00	0.00%	1,212.98	28.20%
1977 - 1979	1,597.29	0.00	0.00%	0.00	0.00%	0.00	0.00%
1978 - 1980	412.19	0.00	0.00%	0.00	0.00%	0.00	0.00%
1979 - 1981	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1980 - 1982	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
1981 - 1983	3,422.98	732.00	21.38%	0.00	0.00%	732.00	21.38%
1982 - 1984	11,041.23	2,732.00	24.74%	0.00	0.00%	2,732.00	24.74%
1983 - 1985	129,653.88	7,279.20	5.61%	0.00	0.00%	7,279.20	5.61%
1984 - 1986	126,892.09	6,547.20	5.16%	0.00	0.00%	6,547.20	5.16%
1985 - 1987	119,273.84	4,547.20	3.81%	0.00	0.00%	4,547.20	3.81%
1986 - 1988	661.19	30.12	4.56%	0.00	0.00%	30.12	4.56%
1987 - 1989	1,569.70	430.12	27.40%	0.00	0.00%	430.12	27.40%
1988 - 1990	2,711.34	430.12	15.86%	5.92	0.22%	424.20	15.65%
1989 - 1991	2,711.34	400.00	14.75%	5.92	0.22%	394.08	14.53%
1990 - 1992	4,535.82	1,817.50	40.07%	5.92	0.13%	1,811.58	39.94%
1991 - 1993	3,404.18	1,817.50	53.39%	0.00	0.00%	1,817.50	53.39%
1992 - 1994	5,409.00	2,162.50	39.98%	0.00	0.00%	2,162.50	39.98%
1993 - 1995	2,014.82	345.00	17.12%	0.00	0.00%	345.00	17.12%
1994 - 1996	17,697.56	10,203.08	57.65%	356.00	2.01%	9,847.08	55.64%
1995 - 1997	16,867.36	9,912.38	58.77%	356.00	2.11%	9,556.38	56.66%
1996 - 1998	18,028.97	9,952.33	55.20%	356.00	1.97%	9,596.33	53.23%
1997 - 1999	11,038.21	1,544.25	13.99%	0.00	0.00%	1,544.25	13.99%
1998 - 2000	9,863.59	1,489.95	15.11%	0.00	0.00%	1,489.95	15.11%

Montana-Dakota Utilities Company
Common Plant
392.10 TRANSPORTATION EQUIPMENT - (TRAILERS)
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1971 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1999 - 2001	8,883.54	1,725.00	19.42%	0.00	0.00%	1,725.00	19.42%
2000 - 2002	1,848.17	573.65	31.04%	0.00	0.00%	573.65	31.04%
2001 - 2003	3,900.61	598.65	15.35%	0.00	0.00%	598.65	15.35%
2002 - 2004	3,719.05	323.65	8.70%	0.00	0.00%	323.65	8.70%
2003 - 2005	16,576.34	3,525.00	21.27%	0.00	0.00%	3,525.00	21.27%
2004 - 2006	14,523.90	3,500.00	24.10%	0.00	0.00%	3,500.00	24.10%
2005 - 2007	19,001.15	4,450.00	23.42%	0.00	0.00%	4,450.00	23.42%
2006 - 2008	20,065.44	5,800.00	28.91%	0.00	0.00%	5,800.00	28.91%
1971 - 2008	208,204.13	104,092.84	50.00	511.83	0.25	103,581.01	49.75

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	20.0
Average Retirement Age (Yrs)	4.9
Years To ASL	15.1
Inflation Factor At 2.75% to ASL	1.51

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	21.76%
1994-2008	**15 - Year Trend**	15.00%
1999-2008	**10 - Year Trend**	26.12%
2004-2008	**5 - Year Trend**	34.05%

Forcasted

Gross Salvage (Five Year Trend)	34.05%
Cost Of Removal	0.38%
Net Salvage	33.67%

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1968	164,451.98	32,704.22	19.89%	25.78	0.02%	32,678.44	19.87%
1969	271,841.22	60,346.77	22.20%	143.11	0.05%	60,203.66	22.15%
1970	259,931.35	66,130.69	25.44%	236.99	0.09%	65,893.70	25.35%
1971	271,416.28	0.00	0.00%	0.00	0.00%	0.00	0.00%
1972	264,790.15	63,974.31	24.16%	164.57	0.06%	63,809.74	24.10%
1973	308,598.98	72,199.39	23.40%	293.41	0.10%	71,905.98	23.30%
1974	241,605.95	77,536.50	32.09%	27.05	0.01%	77,509.45	32.08%
1975	130,372.99	45,884.59	35.19%	0.00	0.00%	45,884.59	35.19%
1976	281,236.74	96,623.97	34.36%	(251.54)	-0.09%	96,875.51	34.45%
1977	382,864.17	134,230.29	35.06%	156.23	0.04%	134,074.06	35.02%
1978	320,558.46	113,702.73	35.47%	0.00	0.00%	113,702.73	35.47%
1979	352,093.67	132,818.59	37.72%	100.47	0.03%	132,718.12	37.69%
1980	366,920.67	129,850.00	35.39%	0.00	0.00%	129,850.00	35.39%
1981	401,828.38	126,607.71	31.51%	1,158.67	0.29%	125,449.04	31.22%
1982	413,793.54	132,072.06	31.92%	1,613.11	0.39%	130,458.95	31.53%
1983	547,143.10	146,554.84	26.79%	539.73	0.10%	146,015.11	26.69%
1984	442,158.28	72,941.51	16.50%	370.55	0.08%	72,570.96	16.41%
1985	2,255,621.28	781,800.12	34.66%	912.53	0.04%	780,887.59	34.62%
1986	539,562.46	64,181.75	11.90%	588.94	0.11%	63,592.81	11.79%
1987	406,940.32	67,112.86	16.49%	2,422.53	0.60%	64,690.33	15.90%
1988	506,735.34	83,356.19	16.45%	5,663.79	1.12%	77,692.40	15.33%
1989	563,190.62	93,145.36	16.54%	2,529.33	0.45%	90,616.03	16.09%
1990	415,225.52	-93,656.92	-22.56%	2,350.94	0.57%	(96,007.86)	-23.12%
1991	502,235.39	79,339.80	15.80%	1,463.28	0.29%	77,876.52	15.51%
1992	134,810.89	14,484.99	10.74%	859.07	0.64%	13,625.92	10.11%
1993	137,487.82	20,294.21	14.76%	317.04	0.23%	19,977.17	14.53%
1994	317,142.07	65,427.26	20.63%	934.85	0.29%	64,492.41	20.34%
1995	148,592.83	10,008.39	6.74%	48.15	0.03%	9,960.24	6.70%

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Annual Activity							
1996	310,798.23	118,826.49	38.23%	43.49	0.01%	118,783.00	38.22%
1997	140,592.98	31,757.00	22.59%	10,417.57	7.41%	21,339.43	15.18%
1998	240,376.81	47,056.25	19.58%	900.00	0.37%	46,156.25	19.20%
1999	272,550.94	54,971.23	20.17%	206.49	0.08%	54,764.74	20.09%
2000	388,959.44	84,465.00	21.72%	0.00	0.00%	84,465.00	21.72%
2001	505,831.14	135,236.30	26.74%	0.00	0.00%	135,236.30	26.74%
2002	115,214.63	44,505.06	38.63%	0.00	0.00%	44,505.06	38.63%
2003	335,793.68	81,933.00	24.40%	0.00	0.00%	81,933.00	24.40%
2004	583,450.75	124,142.50	21.28%	0.00	0.00%	124,142.50	21.28%
2005	421,851.72	74,531.00	17.67%	0.00	0.00%	74,531.00	17.67%
2006	449,922.13	112,620.00	25.03%	0.00	0.00%	112,620.00	25.03%
2007	625,878.69	143,063.17	22.86%	0.00	0.00%	143,063.17	22.86%
2008	488,488.81	123,203.00	25.22%	0.00	0.00%	123,203.00	25.22%

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
1968 - 1970	696,224.55	159,181.68	22.86%	405.88	0.06%	158,775.80	22.81%
1969 - 1971	803,188.85	126,477.46	15.75%	380.10	0.05%	126,097.36	15.70%
1970 - 1972	796,137.78	130,105.00	16.34%	401.56	0.05%	129,703.44	16.29%
1971 - 1973	844,805.41	136,173.70	16.12%	457.98	0.05%	135,715.72	16.06%
1972 - 1974	814,995.08	213,710.20	26.22%	485.03	0.06%	213,225.17	26.16%
1973 - 1975	680,577.92	195,620.48	28.74%	320.46	0.05%	195,300.02	28.70%
1974 - 1976	653,215.68	220,045.06	33.69%	(224.49)	-0.03%	220,269.55	33.72%
1975 - 1977	794,473.90	276,738.85	34.83%	(95.31)	-0.01%	276,834.16	34.84%
1976 - 1978	984,659.37	344,556.99	34.99%	(95.31)	-0.01%	344,652.30	35.00%
1977 - 1979	1,055,516.30	380,751.61	36.07%	256.70	0.02%	380,494.91	36.05%
1978 - 1980	1,039,572.80	376,371.32	36.20%	100.47	0.01%	376,270.85	36.19%
1979 - 1981	1,120,842.72	389,276.30	34.73%	1,259.14	0.11%	388,017.16	34.62%
1980 - 1982	1,182,542.59	388,529.77	32.86%	2,771.78	0.23%	385,757.99	32.62%
1981 - 1983	1,362,765.02	405,234.61	29.74%	3,311.51	0.24%	401,923.10	29.49%
1982 - 1984	1,403,094.92	351,568.41	25.06%	2,523.39	0.18%	349,045.02	24.88%
1983 - 1985	3,244,922.66	1,001,296.47	30.86%	1,822.81	0.06%	999,473.66	30.80%
1984 - 1986	3,237,342.02	918,923.38	28.39%	1,872.02	0.06%	917,051.36	28.33%
1985 - 1987	3,202,124.06	913,094.73	28.52%	3,924.00	0.12%	909,170.73	28.39%
1986 - 1988	1,453,238.12	214,650.80	14.77%	8,675.26	0.60%	205,975.54	14.17%
1987 - 1989	1,476,866.28	243,614.41	16.50%	10,615.65	0.72%	232,998.76	15.78%
1988 - 1990	1,485,151.48	82,844.63	5.58%	10,544.06	0.71%	72,300.57	4.87%
1989 - 1991	1,480,651.53	78,828.24	5.32%	6,343.55	0.43%	72,484.69	4.90%
1990 - 1992	1,052,271.80	167.87	0.02%	4,673.29	0.44%	(4,505.42)	-0.43%
1991 - 1993	774,534.10	114,119.00	14.73%	2,639.39	0.34%	111,479.61	14.39%
1992 - 1994	589,440.78	100,206.46	17.00%	2,110.96	0.36%	98,095.50	16.64%
1993 - 1995	603,222.72	95,729.86	15.87%	1,300.04	0.22%	94,429.82	15.65%
1994 - 1996	776,533.13	194,262.14	25.02%	1,026.49	0.13%	193,235.65	24.88%
1995 - 1997	599,984.04	160,591.88	26.77%	10,509.21	1.75%	150,082.67	25.01%

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)

Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	*Orginal Cost Of Retirements*	*Gross Salvage*		*Cost of Removal*		*Net Salvage*	
		Amount	*%*	*Amount*	*%*	*Amount*	*%*
Three - Year Rolling Bands							
1996 - 1998	691,768.02	197,639.74	28.57%	11,361.06	1.64%	186,278.68	26.93%
1997 - 1999	653,520.73	133,784.48	20.47%	11,524.06	1.76%	122,260.42	18.71%
1998 - 2000	901,887.19	186,492.48	20.68%	1,106.49	0.12%	185,385.99	20.56%
1999 - 2001	1,167,341.52	274,672.53	23.53%	206.49	0.02%	274,466.04	23.51%
2000 - 2002	1,010,005.21	264,206.36	26.16%	0.00	0.00%	264,206.36	26.16%
2001 - 2003	956,839.45	261,674.36	27.35%	0.00	0.00%	261,674.36	27.35%
2002 - 2004	1,034,459.06	250,580.56	24.22%	0.00	0.00%	250,580.56	24.22%
2003 - 2005	1,341,096.15	280,606.50	20.92%	0.00	0.00%	280,606.50	20.92%
2004 - 2006	1,455,224.60	311,293.50	21.39%	0.00	0.00%	311,293.50	21.39%
2005 - 2007	1,497,652.54	330,214.17	22.05%	0.00	0.00%	330,214.17	22.05%
2006 - 2008	1,564,289.63	378,886.17	24.22%	0.00	0.00%	378,886.17	24.22%

Montana-Dakota Utilities Company
Common Plant
392.20 TRANSPORTATION EQUIPMENT - (CARS & TRUCKS)
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 1968 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Three - Year Rolling Bands							
1968 - 2008	16,228,860.40	3,865,982.18	23.82	34,236.13	0.21	3,831,746.05	23.61

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	8.0
Average Retirement Age (Yrs)	4.0
Years To ASL	4.0
Inflation Factor At 2.75% to ASL	1.12

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	28.60%
1994-2008	**15 - Year Trend**	24.44%
1999-2008	**10 - Year Trend**	23.56%
2004-2008	**5 - Year Trend**	22.90%

Forcasted

Gross Salvage (Five Year Trend)	22.90%
Cost Of Removal	0.23%
Net Salvage	22.66%

Montana-Dakota Utilities Company
Common Plant
396.20 POWER OPERATED EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage		Cost of Removal		Net Salvage	
		Amount	%	Amount	%	Amount	%
Annual Activity							
2001	6,082.85	3,000.00	49.32%	0.00	0.00%	3,000.00	49.32%
2002	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2003	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2004	14,192.25	8,000.00	56.37%	0.00	0.00%	8,000.00	56.37%
2005	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%

Montana-Dakota Utilities Company
Common Plant
396.20 POWER OPERATED EQUIPMENT
Forecasted Future Net Salvage
Based Upon Experienced Net Salvage 2001 - 2008

Year	Orginal Cost Of Retirements	Gross Salvage Amount	Gross Salvage %	Cost of Removal Amount	Cost of Removal %	Net Salvage Amount	Net Salvage %
Three - Year Rolling Bands							
2001 - 2003	6,082.85	3,000.00	49.32%	0.00	0.00%	3,000.00	49.32%
2002 - 2004	14,192.25	8,000.00	56.37%	0.00	0.00%	8,000.00	56.37%
2003 - 2005	14,192.25	8,000.00	56.37%	0.00	0.00%	8,000.00	56.37%
2004 - 2006	14,192.25	8,000.00	56.37%	0.00	0.00%	8,000.00	56.37%
2005 - 2007	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2006 - 2008	0.00	0.00	0.00%	0.00	0.00%	0.00	0.00%
2001 - 2008	20,275.10	11,000.00	54.25	0.00	0.00	11,000.00	54.25

Trend Analysis (End Year) **2008**

***Based Upon Three - Year Rolling Averages**

Annual Inflation Rate	2.75%
Average Service Life (ASL)	10.0
Average Retirement Age (Yrs)	-15.2
Years To ASL	25.2
Inflation Factor At 2.75% to ASL	1.98

Gross Salvage
Linear Trend Analysis

1989-2008	**20 - Year Trend**	36.45%
1994-2008	**15 - Year Trend**	36.45%
1999-2008	**10 - Year Trend**	36.45%
2004-2008	**5 - Year Trend**	0.00% *

***Forecasted Gross Salvage Calculates To Less Than 0.00%---Percentage Set To A Floor of 0.00%.**

Forcasted

Gross Salvage (Five Year Trend)	0.00% *
Cost Of Removal	0.00%
Net Salvage	0.00%