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

400 North Fourth Street
Bismarck, ND 58501
701-222-7900
www.montana-dakota.com

November 1, 2023

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
600 E Boulevard Ave #408
Bismarck, ND 58505-0480

RE: Application of Montana-Dakota Utilities Co. for Authority to Increase Rates for Natural Gas Service in North Dakota
Case No. PU-23-___

Montana-Dakota Utilities Co. (Montana-Dakota or Company) hereby electronically submits the enclosed Application and Notice to the North Dakota Public Service Commission (Commission) for authority to increase rates for natural gas service in North Dakota. This filing is made in accordance with the North Dakota Century Code (N.D.C.C) 49-05-05 and the North Dakota Administrative Code (N.D.A.C) 69-02-02-04 and the rules and regulations promulgated by the North Dakota Public Service Commission.

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 natural gas service to its North Dakota customers and that therefore, the current rates are unjust, unreasonable, and not compensatory.

The reason for the increase in rates is driven primarily by the investments made since the last rate case and increases in operating expenses, including the related depreciation expense and taxes, partially offset by an increase in customers and throughput.

Montana-Dakota's last general natural gas rate case was filed in 2020 (Case No. PU-20-379). The resulting increase was 6.0 percent with final rates effective on June 1, 2021.

Montana-Dakota strives to control its costs by continually looking for opportunities that create efficiencies and control costs. In spite of Montana-Dakota's efforts to control costs, the Company sees cost pressures as the need to replace existing infrastructure and add new infrastructure continues.

Authorization of the requested increase in revenues will provide Montana-Dakota a reasonable opportunity to earn a fair rate of return for its North Dakota natural gas operations. The Company proposes a total increase in distribution revenues of $11,640,010, as shown on Statement L, page 1, based on a projected test year for the twelve months ended December 31, 2024. The proposed increase will affect approximately 117,700 natural gas customers in North Dakota. The proposed change in rates is shown below:

	Revenue Increase	
	$	%
Customer Class		
Residential	$ 7,500,074	9.84%
Firm General	3,542,590	4.82%
Air Force Delivery	370,295	20.45%
Small Interruptible	156,728	4.31%
Large Interruptible	70,323	7.02%
Total	$ 11,640,010	7.45%

Please refer all inquiries regarding this filing to:

Mr. Travis Jacobson
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501
travis.jacobson@mdu.com

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

William J. Behrmann
Attorney
ES Attorneys
1100 College Drive, Suite 5
Bismarck, ND 58501
wbehrmann@esattorneys.com

Allison Waldon
Attorney
MDU Resources Group, Inc.
P.O. Box 5650
Bismarck, ND 58506-5650
allison.waldon@mduresources.com

All of the materials included in this Application will be available for public inspection upon request at each of Montana-Dakota's business offices and posted on Montana-Dakota's internet site.

The original and seven (7) copies of this Letter of Transmittal, Application and Notice, Appendices, Testimony and Exhibits, and Statements are hereby filed with the North Dakota Public Service Commission. An electronic copy has also been provided.

Montana-Dakota also herewith submits a check for $175,000 pursuant to the requirements of Section 49-05-04 (11) of the North Dakota Century Code.

Pursuant to N.D.C.C § 49-05-06(2), Montana-Dakota is concurrently submitting an Application and Notice for Interim Increase in Natural Gas Rates in the annual amount of $10,094,595 to take effect January 1, 2024.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Sincerely,

Garret Senger

Garret Senger
Executive Vice President – Regulatory Affairs, Customer Service & Administration
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

Enclosures

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Increased Rates for Natural Gas Service in North Dakota	))))	Case No. PU-23-___

* * * * * *

APPLICATION AND NOTICE

Montana-Dakota Utilities Co., (hereinafter referred to as Montana-Dakota, Applicant, or Company) submits this application to the North Dakota Public Service Commission for authority to increase rates for natural gas service in North Dakota. The Applicant in the above-entitled proceeding respectfully submits the following Application and Notice, tariffs, and information in support thereof.

In support of its Application, Montana-Dakota respectfully states the following:

I.

Montana-Dakota is a Delaware corporation duly authorized to do business in the State of North Dakota as a foreign corporation and that it is doing business in the State of North Dakota as a public utility.

II.

The Company's Certificate of Incorporation and Amendments thereto have previously been filed with the North Dakota Public Service Commission (PSC or Commission). Such Certificate and Amendments are hereby incorporated by reference.

III.

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

Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

IV.

Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota, serves customers in Minnesota and the community of Wahpeton and the surrounding area in North Dakota. In a Settlement in Case Nos. PU-17-490 and PU-17-075 approved by this Commission, the Parties agreed to begin combining all gas operations within North Dakota for reporting purposes, which began in 2018, as a first step to having one North Dakota gas utility operation. In this filing, the Company is proposing to eliminate Great Plains' gas tariff and incorporate the appropriate information into Montana-Dakota's gas tariff.

That the following described rate schedules for Montana-Dakota and Great Plains are presently on file with and approved by the Commission attached hereto as Appendix A.

Montana-Dakota Utilities Co. - Current Tariffs

NDPSC Volume No. 8	Description	Rate
1st Revised Sheet No. 1	Table of Contents	
Original Sheet No. 2	Communities Served	
24th Revised Sheet No. 3	Rate Summary Sheet	
Original Sheet No. 3.1	Rate Summary Sheet	
Original Sheet No. 4	Residential Gas Service	60
Original Sheet Nos. 7-7.1	Air Force	64
Original Sheet No. 8	Air Force Distribution System	65
Original Sheet Nos. 13-13.1	Firm General Gas Service	70

Original Sheet Nos. 14-14.2	Small Interruptible General Gas Service	71
Original Sheet Nos. 15-15.1	Optional Seasonal General Gas Service	72
Original Sheet Nos. 16-16.1	Firm General Contracted Demand Service	74
Original Sheet Nos. 17-17.1	Gwinner Pipeline Capacity Reservation Charge	75
Original Sheet Nos. 24-24.7	Transportation Service	81 & 82
Original Sheet Nos. 27-27.2	Large Interruptible General Gas Service	85
Original Sheet Nos. 29-29.1	Distribution Delivery Stabilization Mechanism	87
Original Sheet Nos. 30-30.5	Cost of Gas – Natural Gas	88
Original Sheet No. 32	Residential Propane Service	90
Original Sheet Nos. 34-34.1	Firm General Propane Service	92
Original Sheet Nos. 41-41.3	Cost of Gas – Propane	99
Original Sheet Nos. 42-42.19	General Provisions	100
Original Sheet Nos. 47-47.1	Gas Meter Testing Program	105
1st Revised Sheet Nos. 61-61.1	Reserved for Future Use	
1st Revised Sheet Nos. 62-62.5	Firm Gas Service Extension Policy	120
Original Sheet Nos. 62.6-62.8	Firm Gas Service Extension Policy	120
Original Sheet No. 66	Replacement, Relocation and Repair of Gas Service Lines	124

Great Plains Natural Gas Company - Current Tariffs

NDPSC Volume 2	Description	Rate
4th Revised Sheet No. 1	Table of Contents	
203rd Revised Sheet No. 1.1	Rate Summary Sheet	
5th Revised Sheet No. 2	Firm Gas Service – General	65
5th Revised Sheet No. 3	Interruptible Gas Service – General	71
2nd Revised Sheet No. 3.1	Interruptible Gas Service – General	71
1st Revised Sheet No. 3.2	Interruptible Gas Service – General	71
3rd Revised Sheet No. 4	Reserved for Future Use	
2nd Revised Sheet No. 4.1	Reserved for Future Use	
1st Revised Sheet No. 4.2	Reserved for Future Use	
4th Revised Sheet No. 5	Interruptible Transportation Service	80
2nd Revised Sheet No. 5.1	Interruptible Transportation Service	80
3rd Revised Sheet No. 5.2	Interruptible Transportation Service	80
2nd Revised Sheet Nos. 5.3-5.4	Interruptible Transportation Service	80
3rd Revised Sheet No. 5.5	Interruptible Transportation Service	80
2nd Revised Sheet Nos. 5.6-5.7	Interruptible Transportation Service	80
3rd Revised Sheet No. 6	Reserved for Future Use	
4th Revised Sheet No. 7	Cost of Gas – Natural Gas	88
1st Revised Sheet No. 7.1	Cost of Gas – Natural Gas	88
155th Revised Sheet No. 8	Reserved for Future Use	
1st Revised Sheet Nos. 9-9.15	General Terms and Condition	100
Original Sheet No. 9.16	General Terms and Condition	100
1st Revised Sheet Nos. 10-10.1	Gas Meter Testing Program	101

1st Revised Sheet No. 11	Firm Gas Service Main and Service Line Extension Policy	105
Original Sheet Nos. 11.1-11.3	Firm Gas Service Main and Service Line Extension Policy	105
Original Sheet Nos. 12-12.1	Interruptible Gas Main and Service Line Extensions Policy	106

V.

Montana-Dakota respectfully hereby files the following described proposed rate schedules for natural gas service, copies attached hereto as Appendix B, which substitute for the rate schedules as noted below. The following described proposed rate schedules are proposed to be effective on a final basis in this Case. As further explained in testimony submitted in this case, the entire North Dakota Great Plains' tariffs will be eliminated.

NDPSC Volume No. 8	Description	Rate
2nd Revised Sheet No. 1	Table of Contents	
1st Revised Sheet No. 2	Communities Served	
25th Revised Sheet No. 3	Rate Summary Sheet	
1st Revised Sheet No. 3.1	Rate Summary Sheet	
Original Sheet No. 3.2	Rate Summary Sheet	
1st Revised Sheet No. 4	Residential Gas Service	60
Original Sheet No. 4.1	Residential Gas Service	60
Original Sheet Nos. 5-5.1	Firm Gas Service - Wahpeton	62
Original Sheet No. 6	Residential Gas Service - Wahpeton	63
1st Revised Sheet No. 7	Air Force	64
1st Revised Sheet No. 13	Firm General Gas Service	70
1st Revised Sheet Nos. 14-14.1	Small Interruptible General Gas Service	71
1st Revised Sheet Nos. 15-15.1	Optional Seasonal General Gas Service	72
1st Revised Sheet Nos. 16-16.1	Firm General Gas Service - Wahpeton	73
1st Revised Sheet Nos. 17-17.1	Firm General Contracted Demand Service	74
Original Sheet Nos. 18-18.1	Gwinner Pipeline Capacity Reservation Charge	75
1st Revised Sheet Nos. 24-24.3	Transportation Service	81 & 82
1st Revised Sheet Nos. 27-27.1	Large Interruptible General Gas Service	85
1st Revised Sheet Nos. 29-29.1	Distribution Delivery Stabilization Mechanism	87
1st Revised Sheet No. 30.4	Cost of Gas – Natural Gas	88
1st Revised Sheet No. 32	Residential Propane Service	90

Original Sheet No. 32.1	Residential Propane Service	90
1st Revised Sheet No. 34	Firm General Propane Service	92
1st Revised Sheet Nos. 42-42.1, 42.3-42.4, 42.6-42.10, 42.12, 42.14-42.17, 42.19	General Provisions	100
1st Revised Sheet No. 47.1	Gas Meter Testing Program	105
Original Sheet Nos. 56-56.1	Summary Billing Plan	115
1st Revised Sheet No. 66	Replacement, Relocation and Repair of Gas Service Lines	124

VI.

That the existing rates of Montana-Dakota are unjust, unreasonable, and not compensatory. The new rates will allow Montana-Dakota an opportunity to fully recover its costs of providing natural gas service and to earn a just and reasonable rate of return on its natural gas property devoted to providing service to its North Dakota natural gas customers.

VII.

The new rates contained herein will provide additional revenues in the annual amount of $11,640,010, based on a 2024 future test year, for natural gas service rendered to customers in North Dakota. This request amounts to a 7.45 percent increase over current natural gas rates.

VIII.

Filed concurrently with this Application and Notice and its Appendices are supporting Statements, and Direct Testimony and Exhibits of Montana-Dakota's witnesses showing the existing rates are unjust, unreasonable, and not compensatory, and that the new rates are just, reasonable, and compensatory.

IX.

Montana-Dakota is submitting an Application and Notice for Interim Increase in Natural Gas Rates in the annual amount of $10,094,595 to be effective 60 days from filing if the Commissions suspends the rate increase sought by the Montana-Dakota through this Application and Notice.

X.

This Application and Notice submitted in accordance with the provisions of N.D.C.C § 49-05-04 and the rules and regulations promulgated by the Public Service Commission of the State of North Dakota and the filing guidelines of the Public Service Commission.

XI.

That, in accordance with Section 49-05-04.1 of the North Dakota Century Code, Montana-Dakota hereby affirms that its future test year forecast is reasonable, reliable, and made in good faith. All basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast. The accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

Dated November 1, 2023.

MONTANA-DAKOTA UTILITIES CO.

Garret Senger

Garret Senger
Executive Vice President - Regulatory
Affairs, Customer Service & Administration
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

STATE OF NORTH DAKOTA)
) :ss
COUNTY OF BURLEIGH)

Garret Senger, being first duly sworn, deposes and says that he is the Executive Vice President of Regulatory Affairs, Customer Service & Administration of Montana-Dakota Utilities Co. that he has read the foregoing Application and Notice, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information, and belief.

Dated November 1, 2023.

Garret Senger

Garret Senger
Executive Vice President - Regulatory Affairs,
Customer Service & Administration
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

OF COUNSEL:

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Allison Waldon
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MDU Resources Group, Inc.
P.O. Box 5650
Bismarck, ND 58506-5650
Allison.Waldon@mduresources.com

STATE OF NORTH DAKOTA)
) :ss
COUNTY OF BURLEIGH)

I, Garret Senger, Executive Vice President of Regulatory Affairs, Customer Service & Administration of Montana-Dakota Utilities Co. do hereby represent that the direct testimony, cost statements, working papers, and other supporting data submitted by Montana-Dakota Utilities Co. as a part of its Application and Notice for Authority to Increase Rates for Natural Gas Service with the North Dakota Public Service Commission, or which are maintained by the Company in support of such filed Application and Notice and which purport to reflect the books of the Company, do in fact set forth the results shown by such books.

Dated November 1, 2023.

Garret Senger
Garret Senger
Executive Vice President – Regulatory Affairs, Customer Service & Administration
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

Subscribed and sworn to before me on November 1, 2023.

Terese M. Birnbaum
Terese M. Birnbaum, Notary Public
Burleigh County, North Dakota
My Commission Expires: 12/30/2023

TERESE M BIRNBAUM
NOTARY PUBLIC
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES DEC. 30, 2023

Montana-Dakota Utilities Co.
North Dakota Natural Gas

Tariffs - Current

Appendix A

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Fort Totten	Max	Steele
Barlow	Garrison	Medina	Surrey
Bismarck*	Glen Ullin	Milnor	Tappen
Burlington	Grafton	Minot	Turtle Lake
Carrington	Gwinner	New Rockford	Underwood
Cavalier	Jamestown	New Salem	Valley City
Cleveland	Langdon	Park River	Walhalla
Dawson	Lincoln	Riverdale	Washburn
Des Lacs	Linton	Ruthville	Wilton
Devils Lake	Mandan	Sandborn	Locations near
		Sheyenne	Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	Stanley
Arnegard	Golva	Ray	Taylor
Beach	Hebron	Regent	Tioga
Belfield	Killdeer	Rhame	Trenton
Berthold	Lefor	Richardton	Watford City
Bowman	Lignite	Ross	Wheelock
Dickinson*	Marmarth	Sentinel Butte	White Earth
East Fairview	Mott	Springbrook	Williston
Epping	New England	South Heart	

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	Rates 88 & 99 Cost of Gas	Total Rate/ Dk
Residential Rate 60	4	$0.8244 per day	$0.000	$4.158	$4.158
Air Force Rate 64	7				
Minot Air Force Base		$2,000.00 per month			
PAR Site		$175.00 per month			
Firm Service			$0.449	$4.158	$4.607
Interruptible Service - PAR			$0.255	$2.738	$2.993
Interruptible Service - MAFB			$0.255	$2.742	$2.997
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.75 per day	$1.174	$4.158	$5.332
Meters rated > 500 cubic feet		$2.13 per day	$0.917	$4.158	$5.075
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$450.00 per month	$0.566	$2.738	$3.304
Optional Seasonal Gas					
Service Rate 72	15				
Meters rated < 500 cubic feet		$0.75 per day	$1.174	$4.285	$5.459
Meters rated > 500 cubic feet		$2.13 per day	$0.917	$4.285	$5.202
Contracted Demand					
Service Rate 74	16		(Demand		
Meters rated < 500 cubic feet		$0.75 per day	Charge)	(Capacity Charge)	$11.990
Meters rated > 500 cubic feet		$2.13 per day	$8.000	(COG/Dk)	$3.742
Transportation Service	24				
Small Interruptible Rate 81		$450.00 per month			
Maximum			$0.566		$0.566
Minimum			$0.102		$0.102
Large Interruptible Rate 82		$1,600.00 per month			
Maximum			$0.237		$0.237
Minimum			$0.061		$0.061
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$1,600.00 per month	$0.237	$2.738	$2.975
Residential Propane Rate 90	32	$0.8244 per day	$0.000	$9.410	$9.410
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.75 per day	$1.174	$9.410	$10.584
Meters rated > 500 cubic feet		$2.13 per day	$0.917	$9.410	$10.327

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$15.00 per check
Manual Meter Reading Change	$26.05 per month
Reconnection charge after termination for nonpayment -During normal business hours -After normal business hours	 See Rate 100 paragraph 22 Current service labor rate per hour
Reconnection charge after termination for causes defined in Rate 100 paragraph 22 -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	 Minimum- $30.00 (See Rate 100 § V 21) Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

RESIDENTIAL GAS SERVICE Rate 60

Availability:

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

Rate:

Basic Service Charge:	$0.8244 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

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

AIR FORCE Rate 64

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$2,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$175.00 per month
Distribution Delivery Charge:	
Firm Service	$0.449 per dk
Interruptible Service	$0.255 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

1. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If the 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 Service distribution delivery charge and cost of gas rates set forth above, 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.

2. CONTRACT – Terms of service other than the rate shall be specified in contracts between Minot Air Force Base, and PAR and the Company.

3. The foregoing schedule is subject to Rates 100 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

AIR FORCE Distribution System Rate 65

Availability:

Operation and maintenance of the Minot Air Force Base distribution system near Minot, North Dakota.

Rate:

Distribution System Operation and Maintenance Fee	$35,500.00 per month (months 1-36) $38,000.00 per month (month 37 forward)
Amortization of Purchase Price	$(3,053.00) per month

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

1. Terms of service including transition period fees shall be specified by contract between Minot Air Force Base and the Company.

2. The amortization on purchase price amount shall be a credit to the Minot Air Force Bill each month.

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

Date Filed:	August 26, 2020	**Effective Date:**	Service rendered on and after June 1, 2021
Issued By:	Travis R. Jacobson Director - Regulatory Affairs	**Case No.:**	PU-20-379

FIRM GENERAL GAS SERVICE Rate 70

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.174 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.917 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.

FIRM GENERAL GAS SERVICE Rate 70

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 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:

In all communities served for all interruptible 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 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 billed at Firm General Gas Service Rate 70. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$450.00 per month	
Distribution Delivery Charge:	Maximum $0.566 per dk	Minimum $0.102 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. 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 charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify 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 the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

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

Availability:

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

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.174 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.917 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.

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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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

General Terms and Conditions:

1. The 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 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.75 per day
For customers with meters rated over 500 cubic feet per hour	$2.13 per day
Distribution Demand Charge:	$8.00 per dk per month of billing demand
Capacity Charge per Monthly Demand dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas: Commodity per dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to meter installation.

General Terms and Conditions:

1. Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable for a minimum period of one year.

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

GWINNER PIPELINE CAPACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above.   All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Firm Gas Service Extension Policy Rate 120 or Interruptible Service Extension Policy Rate 119.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

TRANSPORTATION SERVICE Rates 81 and 82

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through 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 by the Company.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
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 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.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load 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, on an interruptible basis, pursuant to 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:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:	
Rate 81	$450.00 per month
Rate 82	$1,600.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.566	$0.237
Minimum Rate per dk	$0.102	$0.061

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. The 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:
   a. To qualify for gas transportation service a 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.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 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. The 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 the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – 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.11.

5. 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 charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

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

   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.21.

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

b. In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

c. 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 a customer from correcting an imbalance which results in a penalty.

10. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 10(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Averages Prices" published by Gas Daily for CIG Rockies and Northern Ventura during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

11. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

c. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

12. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise the Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC timelines, of the dk requirements customer has requested to be delivered at each delivery point 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 a customer in excess of the quantities of gas to be delivered to customer.

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

13. WARRANTY – The 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 the 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.

14. FACILITY EXTENSIONS - If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

15. 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.13, or any amendments or alterations thereto.

16. 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.

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

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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served for all interruptible general gas service customers whose interruptible natural gas load 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 billed at Firm General Gas Service Rate 70. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

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:	$1,600.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.237 per dk	$0.061 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the charges applicable under Firm General Gas Service Rate 70 (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS - Customer will be required as specified in the service agreement to notify 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 the customer equal to the penalty amounts Company must pay to the interconnecting pipeline caused by customer's action.

5. METERING REQUIREMENTS –Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company, prior to the initiation of service hereunder.

   Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

   Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

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

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 Firm General Service Rates 70 and 92 shall be subject to decreases or increases under the DDSM.

Distribution Delivery Stabilization Mechanism:

A DDSM will be determined for each customer taking service under Firm General Service Rates 70 and 92 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 Firm General Services Rate 70 or 92. 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 70 or 92
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

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

Definitions:

Heating Degree Days	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	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. Firm General Service Rate Code 700 = 0.05012 Firm General Service Rate Code 701 = 0.90499 Firm General Service Rate Code 920 = 0.04802 Firm General Service Rate Code 921 = 1.79780
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of natural gas supply, (b) amortization of the Unrecovered Purchased Gas Cost Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least twenty-five (25) cents per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing. 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, the overall rate of return on prepaid demand and commodity charges and gas storage balances required to maintain the system gas supply.

   (b) The COG 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 COG will be in effect and annual dk requirements.

(4) The return on prepaid demand and commodity balances and storage balances shall be computed on an annual basis at the overall rate of return on rate base.

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 for firm customers 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) Demand costs for firm general contracted demand customers shall be stated on the incremental MDDQ basis.

(4) 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 dks sold in each state, regardless of the actual points of delivery of such gas.

(5) The return requirement related to prepaid demand and commodity charges and gas storage balances shall be included on a per dk basis. The prepaid demand and storage balances shall be apportioned to all states on the basis of each state's MDDQ. The prepaid commodity charges shall be apportioned to all states on the basis of annual dks sold in each state. The unit cost shall be calculated using a thirteen-month average balance and the currently authorized return on rate base.

(6) All costs related to specific end-use transactions 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 COG 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.

4. Surcharge Adjustment:

(a) All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on October 1 of each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered 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.

5. Unrecovered Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for gas supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five 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.

(3) Refunds received from supplier(s) with respect to gas supply.

(4) Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

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

(b) (1) The amount to be included in Account 191 in order to reflect the items specified in Subsections 5(a)(1), (2), and (3) shall be calculated as follows:

(i) 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 supplier's 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 natural gas sales units (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.

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

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each rate schedule. The resulting amounts shall be reflected in an Account 191 for each rate schedule.

(2) Montana-Dakota will calculate carrying charges on the amounts in Account 191 at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The amount to be included in Account 191 for carrying charges shall be determined as follows:

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to Rates 60, 70, 72, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file to change the COG at least 20 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant pipeline tariff sheets supporting costs claimed.

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	$0.8244 per day
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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane component is subject to change on a monthly basis.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

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

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$0.75 per day
Distribution Delivery Charge:	$1.174 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.13 per day
Distribution Delivery Charge:	$0.917 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

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

COST OF GAS – PROPANE Rate 99

1. **Availability:**
   This rate schedule constitutes a Cost of Gas (COG) provision and specifies the procedure to be utilized to adjust the rates for propane gas sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of propane supply, (b) amortization of the Unrecovered Purchased Cost of Gas Account and (c) grain drying margin sharing.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first day of each month, unless the Commission shall otherwise order.

   (b) Montana-Dakota shall file to reflect changes in its average cost of propane supply only when the amount of such change in COG is at least twenty-five (25) cents per dk. The adjustment to be effective May 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Montana-Dakota's cost of propane supply as compared to the cost of propane supply approved in its most recent COG filing. The cost of propane supply shall include, but not be limited to, all commodity and transportation charges incurred by Montana-Dakota for such propane supply.

   (b) The propane commodity cost shall reflect all commodity related propane costs estimated to be incurred for the month the COG will be in effect and estimated dk purchases.

   The unit cost per dk for the month shall be the commodity costs divided by estimated dk purchases for the month.

4. **Surcharge Adjustment:**
   All propane sales schedules shall be subject to a Surcharge Adjustment to be effective on May 1 each year. The Surcharge Adjustment per dk sold shall reflect amortization of the applicable balance in the Unrecovered Purchased Cost of Gas Account calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment.

5. Unrecovered Purchased Gas Account:

(a) Items to be included in the Unrecovered Purchased Gas Account (Account 191), as calculated in accordance with Subsection 5(b) are:

(1) Charges for propane supply which Montana-Dakota is unable to reflect in the COG by reason of the twenty-five cent minimum limitation set forth in Subsection 2(b).

(2) Amounts of increased/decreased charges for propane supplies that were paid during any period after the effective date of the most recent approved rates, but not yet included in propane sales rates.

(3) Carrying charges or credits.

(b)

(1) The amount to be included in Account 191 in order to reflect the items specified in Subsections 5(a)(1) and (2) shall be calculated as follows:

(i) Montana-Dakota shall first determine each month the unit cost for that month's propane supply.

(ii) Montana-Dakota shall then subtract from each month's unit cost, the unit cost for propane supply, which is reflected in the currently effective COG.

(iii) The resulting difference (which may be positive or negative) shall be multiplied by the dks sold during that month under each propane rate schedule. The resulting amounts shall be reflected in an Account 191 for each rate schedule.

Montana-Dakota will calculate carrying charges on the amounts in Account 191 as follows:

Each month, Account 191 shall be debited (on a debit balance) or credited (on a credit balance) for a carrying charge, which shall be the product of (i) and (ii) below:

(i) The balance on Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the three-month Treasury Bill rate as published monthly by the Federal Reserve Board. The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in Account 191 specified in Subsections 5(a)(1) and (2) and the amounts in the supplementary Account 191 specified in Subsection 5(b)(2)(ii).

6. Grain Drying Margin Sharing Mechanism:

At the time of each surcharge adjustment, pursuant to Paragraph 4 of Rate 88, the Company will compute a credit to Rates 90 and 92 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service rates as established in Case No. PU-13-803, including prior period over or under collected balances.

7. Time and Manner of Filing:

(a) Montana-Dakota shall file each COG at least 10 days prior to the proposed effective date. Each filing by Montana-Dakota shall be made by means of revised COG sheets identifying the amounts of the adjustments and the resulting currently effective COG rates.

COST OF GAS – PROPANE Rate 99

(b) Each filing shall be accompanied by detailed computations, which clearly show the derivation of the relevant amounts, a concise statement of the reasons for any change and copies of any relevant material supporting costs claimed.

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GENERAL PROVISIONS 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 North Dakota 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 – A customer requesting Company to provide service.

COMMISSION – Public Service Commission of the State of North Dakota.

COMPANY – Montana-Dakota Utilities Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the 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. Also includes any reduction of transportation natural gas service deemed necessary by the Pipeline.

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly 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 Company's meter(s) located on customer's premises.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

GAS DAY – Means a period of twenty-four 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 Company.

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

PIPELINE – The transmission company(s) delivering natural gas into Company's system.

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, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

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

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A 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 the customer desiring the service. The Company may refuse a customer or terminate service to a 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 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. The 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 by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 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 Company's sole discretion, 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.

4. ACCESS TO CUSTOMER'S PREMISES – Company representatives, when properly identified, shall have access to customer's premises Monday through Friday, 8:00 a.m. to 5:00 p.m., unless an emergency requires access outside of these hours, for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

5. COMPANY PROPERTY – The customers 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.

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

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

8. NOTIFICATION OF LEAKS – The customer shall immediately notify the Company of any escape of gas in or about the customer's premises.

9. TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their 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.

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

11. 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, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

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 the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

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, or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold 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. Company agrees to indemnify and hold customer harmless from any and all

injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during 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 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 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 authorization 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 the 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 twelve months unless there is a material change in the 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: separately metered units, such as single private residences, single apartments, mobile homes with separate meters and sorority and fraternity houses. In addition, auxiliary buildings on the same premise as the living quarters when used for residential purposes may be served on the residential rate. 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, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, master metered 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), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the 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 on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. 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 regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart 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.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with the following criteria:
   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

   A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the 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 twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume 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. Company will test meters in accordance with applicable state utility rules and regulations.

(b) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided for in the applicable rate schedule.

(c) Customer may install, operate, and maintain at its sole expense, equipment for the purpose of measuring the amount of natural gas delivered over any measurement period, provided the equipment shall not interfere with such delivery or with the Company's meter.

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 used to reflect the heating value of the 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 at a temperature base of sixty degrees Fahrenheit (60ºF). All measurement of natural gas by orifice meter shall be 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 AGA-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.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60 or 90, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60 or 90), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

refund the customer the amount of the overbilled for a period not to exceed six years from the date of payment.

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

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1 percent per month will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's bank.

15. MANUAL METER READING CHARGE– A monthly Manual Meter Reading Charge of $26.05 per month will be assessed customer(s) who have requested, and received Company approval, to have their meter read manually each month in lieu of an AMR-equipped meter read. Customer(s) agree to contract for the manual reading of the meter for a minimum period of one year.

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

17. UTILITY CUSTOMER SERVICES:
    (a) The following services will be performed at no charge regardless of the time of performance:
        (1) Fire and explosions calls.

        (2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

        (3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

        (4) Maintenance or repair of Company-owned facilities on the customer's premises.

        (5) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

    (b) The following service calls will be performed at no charge during the Company's normal business hours:
        (1) Cut-ins and cut-outs.

        (2) High bills or inadequate service complaints.

        (3) Location of underground Company facilities for contractors, builders, plumbers, etc.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

    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.

    To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

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

20. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

    Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours. The Capacity Reservation Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

    Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General Rate 70 = 174 dk; Large Firm General Rate 70 = 1,220 dk; Small Firm General Propane Rate 92 = 170 dk; Large Firm General Propane Rate 92 = 1,898 dk; and Small Interruptible = 5,918 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours. The Capacity Reservation

Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by 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 of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

23. DISCONNECTION 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 the 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 Company facilities.

The Company may collect a reconnect fee of $30.00 before restoring gas service, which has been disconnected for the above causes.

24. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company 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.

(a) Examples of unauthorized use of service includes but is not limited to, tampering or unauthorized reconnection by the following methods:
   (1) Bypass piping around meter.
   (2) Bypass piping installed in place of meter.
   (3) Meter reversed.
   (4) Meter index disengaged or removed.
   (5) Service or equipment tampered with or piping connected ahead of meter.
   (6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
   (7) Gas being used after service has been discontinued by the Company. 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.

(b) In the event that there has been unauthorized use of service, customer shall be charged for:
   (1) Time, material and transportation costs used in investigation.
   (2) Estimated charge for non-metered gas.
   (3) On-premise time to correct situation.
   (4) Any damage to Company property.
   (5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
   (1) All delinquent bills, if any.
   (2) The amount of any Company revenue loss attributable to said tampering.
   (3) 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 number 20.b above.
   (4) Reconnection fee applicable.
   (5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

25. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

26. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
Rate 119 – Interruptible Gas Service Extension Policy
Rate 120 – Firm Gas Service Extension Policy
Rate 124 –Replacement, Relocation and Repair of Gas Service Lines

Applicability:

This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all new meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or the shipment shall be returned to the manufacturer.

Testing Process for Meters in Service

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller, will be combined into a single random test program. The population of meters shall come from the states of North Dakota, Montana, South Dakota, and Wyoming.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot (lot) to be part of a random population for testing.

4. All active meters will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of + 2.0%.

GAS METER TESTING PROGRAM Rate 105

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

   a. A meter for which the sample is satisfactory will remain in service.

   b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

   c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

      i. If evaluation determines the group is homogeneous, then the entire group will be removed.

      ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting

Montana-Dakota shall file reports of its meter test results by December 1 for the meter testing conducted between June 30 of the previous year and July 1.

Reserved for Future Use

Reserved for Future Use

This rate schedule outlines the policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm and interruptible sales service and interruptible transportation service to customers.

(A) General Rules and Regulations Applicable to all Gas Service Extensions.

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

2. The Company shall 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 (MAI) =

$$\frac{\text{Annual Basic Service Charge} + (\text{Project's Estimated } 5^{th} \text{ Year Annual Dk} \times \text{Distribution Delivery or Demand Charge})}{\text{LARR}}$$

   where: LARR = Levelized Annual Revenue Requirement Factor of 12.328%

4. The cost of the firm gas 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), any permits required to construct the extension, and other costs up to, and including, the riser.

   The cost of an interruptible gas extension project shall include the gas main extension(s), valves, service line(s), regulators, meters, any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), any permits required to construct the extension, and other costs up to, and including the riser. Any remote data acquisition equipment costs required shall be subject to the terms and conditions of service specified in the applicable interruptible service rate schedule.

The service line is that portion of the gas service extending from the gas main to the connection at the house regulator and/or meter.

5. The cost of an extension shall reflect those costs necessary to serve the new load using sound engineering and cost estimating standards. The engineering, design, and method of construction shall be determined by the Company in accordance with its construction standards. The location and route of the extension shall be established by the Company.

   Nothing contained herein shall prohibit the Company from installing additional facilities in excess of those used to calculate the cost of the extension, if such facilities are reasonably justified by anticipated future load to be served, or where such additional facilities will be used for general system improvement or reasonable orderly development. Costs above the minimum required to serve the load requested by the customer will be considered system betterment costs and paid by the Company. The cost to upgrade existing facilities or the installation of new facilities that are mutually beneficial will be shared pro rata based on load, where applicable.

   Any additional facilities installed as part of an extension project that have been designated as system betterment in accordance with this paragraph will be listed individually with supporting details and justification in the Company's next general rate case.

6. A customer or developer extension may also be subject to additional costs that may not be considered part of the extension and may be separately charged to the customer or developer. The following is not an all-inclusive list, but includes some additional costs that may be incurred for an extension:

   a. Winter Construction: When the main or service line is installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30 or because the customer's property, or the streets leading up to, are not ready to receive the service or main by such date, such work will be subject to winter construction charges when winter conditions of ground frost and/or snow exist, for the entire length of underground service or main installed. Winter construction will not be undertaken by Company where prohibited by law or where it is not practical to install a service or main during the winter season. The Company reserves the right to charge the actual amount for any winter construction expenses. All winter construction charges are non-refundable and are in addition to any normal construction charges.

b. Abnormal and/or Unusual Conditions: When abnormal conditions are present and/or unusual expenditures are incurred after the start of construction, the customer or developer will pay the Company for the excess costs incurred by the Company in order to expand the system. The Company reserves the right to charge for any abnormal and/or unusual conditions. Circumstances that cause increased installation costs for a distribution system expansion include but are not limited to rock, safety-related issues, legal challenges, routing, right-of-way acquisition, obstructions, hindrances, crop damage, governmental or third-party requirements.

c. Changes After Start of Construction: The customer or developer shall be charged a non-refundable contribution in aid of construction for the relocation or change in planned construction methods of any Company facilities after construction is started as a result of changes in:
   1. Grade changes in excess of four (4) inches,
   2. Lot line(s),
   3. Site conditions including driveways, fences, or other impediments to construction,
   4. Easement boundaries which had previously been considered final and,
   5. Any other changes requested by the customer after original project costs were estimated and agreed to by customer.

7. All extensions are subject to the execution of the applicable extension agreement between the customer or developer and the Company.
   a. Customer Application for Gas Service,
   b. Customer Gas Service Extension Agreement,
   c. Developer Gas Service Extension Agreement Type A, where project not cost justified and contribution required,

d. Developer Gas Service Extension Agreement Type B, where project cost justified with commitment to number of new customers, and
e. Large Customer Gas Service Extension Agreement.

8. Upon project completion, main extension projects greater than $100,000 shall have their contribution amount adjusted to reflect actual costs and an additional charge may be levied or refund provided to customer as specified in the extension agreement with the customer.

9. 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.

10. 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) <u>Customer Extensions.</u>

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

1. Contributions where project costs are less than or equal to $500,000.
   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.

   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. A minimum annual charge set forth in an agreement between customer and Company, or

iv. The Company, at its sole discretion, may allow the customer to post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, or letter of credit, 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.

v. In the event a customer's letter of credit, bond, or other financial obligation fails to provide the required financial contribution in accordance with this section, the Company will not seek recovery of those funds in a future rate proceeding.

2. Contributions where project costs exceed $500,000 and all Interruptible Gas Extension Projects.
   a. Customer will be provided an estimated MAI in accordance with Paragraph (A)3, but due to the size of these projects and to ensure estimated customer load is realized, the customer will be required to contribute an amount equal to the total cost of construction prior to the start of construction.

   b. The contribution shall be made by:
      i. A one-time payment prior to construction, or
      ii. The Company, at its sole discretion, may allow the customer to post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, or letter of credit, 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.

3. If within the five-year review period from the extension(s) in service date, the number of active customers and related volumes exceeds the fifth-year projections used to determine cost participation, the Company shall recompute the contribution requirement by recalculating the MAI.

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

5. If within the five-year review period from the extension(s) in service date, an additional main extension is required to serve new customers, the additional main extension shall be considered a separate new extension. The commonly used main for the new customer(s) will be credited to the existing customer(s) projects.

6. 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 or letter of credit, will be notified of any reduction in surety requirements.

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

7. Incremental Expansion Surcharge

    a. The Company, in its sole discretion, may offer an Incremental Expansion Surcharge (Surcharge) to a project consisting of 10 or more customers requesting service when the total estimated cost would otherwise have been prohibitive under the Company's present rates and gas service extension policy. If the Company and customers mutually agree that the project will be funded through a Surcharge, the project will be designated an expansion area and the Surcharge will be applicable to all connections within the expansion area. The contribution requirement to be collected under the Surcharge shall be the amount of the capital expenditure in excess of the MAI determined in accordance with Paragraph (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 designed to provide recovery of the contribution requirement within the 5-year period.

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 designed to provide recovery of the contribution requirement up to, but not to exceed, ten years.

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 extensions to areas such as a subdivision or a mobile home court, in which a developer is installing roads, utilities, etc., before housing is built:

1. Contributions where project costs are less than or equal to $500,000.

   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.

2. Contributions where project costs exceed $500,000 and all Interruptible Gas Extension Projects.

   Developer will be provided an estimated MAI in accordance with Paragraph (A)3, but due to the size of these projects and to ensure estimated customer load is realized, the developer will be required to contribute an amount equal to the total cost of construction prior to the start of construction.

3. The contribution shall be made by:

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

   b. The Company, at its sole discretion, may allow the developer to post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction. Such bond, issued by a bonding company authorized to do business in the state, or letter of credit, 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.

   c. In the event a developer's letter of credit, bond, or other financial obligation fails to provide the required financial contribution in accordance with this section, the Company will not seek recovery of those funds in a future rate proceeding.

4. If within the five-year review period from the extension(s) in service date, an additional main extension is required to serve additional developments under a new developer the projects will be considered separate projects. The commonly used main for the new development will be credited to the existing development(s) if a new developer.

5. Refund

   a. If within the five-year review period from the extension(s) in service date, the number of active customers and related volumes exceeds the fifth-year projections used in the cost estimate of the MAI, the

Company shall recompute the contribution requirement by recalculating the MAI. Such recalculation shall be done annually based upon the anniversary of the extension(s) in service date.

b. The Company will refund to the original developer which executed the extension agreement with the Company and made the contribution the amount required to reduce its contribution to the recalculated contribution requirement unless the Company has received a notice of assignment of payment from the original developer, in writing, prior to the date of the refund. The Company shall be justified in relying upon receipt or non-receipt of such notice. No refunds will be made for amounts less than $25. Developers who have posted a bond, or a letter of credit will be notified of any reduction in surety requirements.

REPLACEMENT, RELOCATION
AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

3. 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 the Firm Gas Service Extension Policy - Rate 120.

Great Plains Natural Gas Co.
North Dakota Gas Tariffs – Current

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GREAT PLAINS NATURAL GAS CO.
A Division of Montana-Dakota Utilities Co.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
203rd Revised Sheet No. 1.1
Canceling 202nd Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/dk
Firm Gas Service - General Rate 65	2	$0.250 per day	$0.9220 per dk	$3.9186	$4.8406
Interruptible Gas Service - General Rate 71	3	$180.00 per month	(Maximum) $0.6690 per dk	$3.3222	(Maximum) $3.9912
Transportation Service Rate 80	5	$180.00 per month	(Maximum) $0.6690 per dk		(Maximum) $0.6690

Date Filed: October 31, 2023

Effective Date: Service rendered on and after November 1, 2023

Issued By: Travis R. Jacobson
Director - Regulatory Affairs

Case No.: PU-20-379

FIRM GAS SERVICE – GENERAL Rate 65

Availability:

Service under this schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. See Rate 100 §III.2 for availability of firm gas service. Service under this rate shall not be subject to curtailment or interruption.

Rate:

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$0.922 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Cost of Gas:

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

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71

Availability:

Service under this schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in firm service agreement. The firm service volumes are subject to available capacity. Customer's firm load shall be billed at Firm Gas Service – General Rate 65. For interruptible purposes, the maximum daily firm requirements shall be set forth in the firm service agreement.

Rate:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.669 per dk
Minimum	$0.130 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge

Cost of Gas:

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

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.13, or any amendments or alterations thereto.

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 the Company's firm general gas service rate, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. 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 Gas Service – General Rate 65 (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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

4. OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify Company of an anticipated change in daily operations.

INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71

Failure to comply with requirements specified in the service agreement may result in the assessment of penalties to the customer equal to the penalty amounts Company must pay to the interconnecting pipeline(s) caused by customer's action.

5. METERING REQUIREMENTS –
   a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

   b. Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

      Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

6. The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Reserved for Future Use

Reserved for Future Use

Reserved for Future Use

INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80

Availability:

Service under this rate schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. 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. To obtain transportation service, a customer must meet the general terms and conditions of service provided hereunder and enter into a gas transportation agreement upon request of the Company.

Rate:

Basic Service Charge:	$180.00 per month
Distribution Delivery Charge:	
Maximum	$0.669 per dk
Minimum	$0.130 per dk

Customers shall pay Basic Service Charge plus a negotiated rate not to exceed the maximum rate or less than the minimum rate specified above.

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

1. CRITERIA FOR SERVICE: In order to receive transportation service, customer must qualify under the Company's applicable natural gas transportation service rate and comply with the general terms and conditions of the service provided herein. The 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:
   a. To qualify for gas transportation service a 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.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 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 under the Firm Gas Service – General Rate 65 (distribution delivery charge and cost of gas). 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. The 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 the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – 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.11.

5. 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 Gas Service – General Rate 65 (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.

6. 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 the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 6.a. Gas volumes supplied by Company will be charged at the Firm Gas Service – General Rate 65 (distribution 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.

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

   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.18.

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

   In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.

   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 a customer from correcting an imbalance which results in a penalty.

9. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

   a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

   Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Average Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

10. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

11. DAILY NOMINATION REQUIREMENTS:
    a. Customer or customer's shipper or agent shall advise Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC time lines, of the dk requirements customer has requested to be delivered at each delivery point 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 a customer in excess of the quantities of gas to be delivered to customer.

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

12. WARRANTY – The 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 the 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.

13. FACILITY EXTENSIONS – If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.

14. 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.13, or any amendments or alterations thereto.

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

16. The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Reserved for Future Use

COST OF GAS – NATURAL GAS RATE 88

1. **Applicability:**
   This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Great Plains rate schedules in order to reflect: (a) changes in Great Plains' average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.

2. **Effective Date and Limitation on Adjustments:**
   (a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.

   (b) Great Plains shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.

3. **Cost of Gas:**
   (a) The monthly COG shall reflect changes in Great Plains' cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.

   (b) Firm Demand - The average cost of demand for Firm Gas Sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve month weather normalized sales volumes applicable for the entire Great Plains' gas system.

   (c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.

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

4. **Gas Cost Reconciliation (GCR)**
   (a) For each twelve-month period ending August 31, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective October 1 of each year. This adjustment shall include:

1. The balance in the (over) under recovered gas cost account as of August 31.
2. The difference between actual and recovered gas costs for each customer class for the twelve months ending August 31. The amount may be an under recovery or (over) recovery.
3. Demand costs recovered from the interruptible sales customers will be credited to the firm general service customers.
4. Any refunds from suppliers of gas or pipeline services.
5. Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on October 1 and remain in effective for a twelve (12) month period.

Reserved for Future Use

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 North Dakota 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 – A customer requesting Company to provide service.

COMMISSION – Public Service Commission of the State of North Dakota.

COMPANY – Great Plains Natural Gas Co.

COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the 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. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.

CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by 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 Company's meter(s) located on customer's premises.

EXCESS FLOW VALVE - Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

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

INTERRUPTIBLE CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency that will cease the use of natural gas or transportation service when deemed necessary by Company.

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

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

PIPELINE – The transmission company(s) delivering natural gas into Company's system.

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

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

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. CUSTOMER OBLIGATIONS:

1. APPLICATION FOR SERVICE – A 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 the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of 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. The customer will be responsible for payment of all service furnished through the date of discontinuance.

2. INPUT RATING – All new customers whose consumption of gas for any purpose will exceed an input of 2,000,000 Btu per hour, metered at a single delivery point, shall consult with the Company and furnish details of estimated hourly input rates 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 Company's sole discretion, 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 8 a.m. to 5 p.m. Monday – Friday unless an emergency situation requires access outside of these hours for the purpose of reading meters, making repairs, making inspections, removing the Company's property or for any other purpose incidental to the service.

4. COMPANY PROPERTY – The customers 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 – The customer shall not disconnect, change connections, make connections or otherwise interfere with 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(s) over gas facilities, the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

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

8. TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their 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 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, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

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, devices owned, installed or maintained by the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues, and appliances on the customer's side of the point of delivery.

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 the customer's premises, except loss, injuries, death or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold 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. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from 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 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 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 authorization 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. 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 the 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 twelve months unless there is a material change in the 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. SERVICE FACILITIES ON CUSTOMER PREMISES – The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premises. Customer shall pay an installment or connection charge based upon the following rates:

   (a) New Service Line Construction:

      (1) Minimum connecting charge, per meter, covering the cost of service connection, general inspection, and gas turn-on and payable at the time of sign-up is $25.00 for customers with gas input loads up to 400,000 Btu/hour; $50.00 for customers with gas input loads above 400,000 Btu/hour and $100.00 for interruptible customers.

      (2) Service line installation charges shall be based upon the lesser of the Company's labor and material rates or the current cost per foot.

   Length of service line shall be determined by measurement made from customer's property line to stop value on the service riser.

   (b) Additional meters to existing service lines and inactive line connections:

   A $25.00 connection charge covering the cost of service connection, general inspection, and gas turn-on will be collected at time of application from each individual requesting an additional meter to an existing service line or connection to an inactive line.

   (c) Relocation of Existing Meters and Service Lines:

   When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.

4. TEMPORARY SERVICE – At the discretion of the Company, temporary service may be rendered to a customer's premise. The Company may require the customer to bear the cost of installing and removing the service

in excess of any salvage realized. Advance installation payment may be required prior to installing the service.

The customer shall pay the regular rates applicable to the class of service rendered.

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

6. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart 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.

7. 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.

   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the 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 twelve months, provided prompt payment record has been established.

8. METERING AND MEASUREMENT-
   (a) Company will meter the volume 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. Company will test meters in accordance with applicable state utility rules and regulations.

   (b) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided in the applicable rate schedule.

9. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be (1) dekatherm (dk), unless otherwise specified. One dk equals 10 therms or 1,000,000 Btu's. Dk 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 used to reflect the heating value of the gas delivered.

10. 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 at a temperature base of sixty degrees Fahrenheit (60ºF). All measurement of natural gas by orifice meter shall be 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 AGA-3/NX-19, as amended, supercompressibility calculation.

Local sales base pressure is defined as five ounces per square inch gauge pressure plus local average atmospheric pressure.

11. PRIORITY OF SERVICE – Priority of Service from Highest to Lowest:
    (a) Priority 1 – Firm sales services.
    (b) Priority 2 – Interruptible sales and interruptible transportation services.
    (c) Gas scheduled to clear imbalances.

    Company 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 Company system.

    Company reserves the right to provide service to customers with 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, Company will reinstate sales and/or transportation of gas according to each customer's original priority.

12. EXCESS FLOW VALVES – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill, or 22 days from date of bill. An amount equal to 1 1/3% per month will be applied to any unpaid balance if not paid by the due date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for each check charged back to the Company by a bank.

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

16. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

    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.

    To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

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

18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee of $30.00.

    Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required remote data acquisition equipment is necessary.

19. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by 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 of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

20. DISCONNECTION 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 the 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 Company facilities.

The Company may collect a reconnect fee of $30.00 before restoring gas service, which has been disconnected for the above causes.

21. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company 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.

(a) Examples of unauthorized use of service include the following, but are not limited to:

(1) Bypass piping around meter.
(2) Bypass piping installed in place of meter.
(3) Meter reversed.
(4) Meter index disengaged or removed.
(5) Service or equipment tampered with or piping connected ahead of meter.
(6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.
(7) Gas being used after service has been discontinued by the Company.
(8) 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.

(b) In the event that there has been unauthorized use of service, customer shall be charged for:

(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.
(5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.

(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) 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 number 21.b above.
(4) Reconnection fee equal to the Company's minimum service charge.

(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

22. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service was provided under Rate 65, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where service was provided under an interruptible service schedule, the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and refund the customer the amount of the overbilled.

GAS METER TESTING PROGRAM Rate 101

Applicability:

This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.

Testing Process for New Meters

1. Meter supplier(s) shall provide test data for all meters.

2. A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or shipment shall be returned to the manufacturer.

Testing Process for Meters in Service:

1. This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.

2. All active meters, 650 cfh and smaller will be combined into a single random test program. Great Plains meters shall be combined with Montana-Dakota Utilities Co. meters for purposes of random sample testing only.

3. At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot to be part of a random population for testing.

4. All active meters rated at 650 CFH and smaller, will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of +2.0%.

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable

quality level of 15%. The following actions will be taken based on the test results:

a. A meter for which the sample is satisfactory will remain in service.

b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% if the sample registers over 102%

   i. If evaluation determines the group is homogeneous, then the entire group will be removed.

   ii. If group is not homogeneous and a subset of the group is found defective, the subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting:

Great Plains shall file reports of its meter test results by December 15 for the meter testing conducted for the previous calendar year.

FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105

The Company will install gas main extensions using the following guidelines applicable to firm gas main extensions:

a) The term “main” refers to the facilities that are typically constructed from a border station or regulator station with no particular terminus at a building or structure. Mains are normally installed in streets, alleys, dedicated public ways or dedicated utility easements.

b) Customer refers to customer ultimately taking natural gas service or a developer request to provide natural gas service to residential customers.

c) Cost Participation. Cost participation for firm gas extensions shall be determined as follows:

   i) Extensions 95 Feet or Less – The Company will extend a gas main up to, but not to exceed, 95 feet per home projected to be connected within twelve (12) months from the start of construction where natural gas is the primary fuel used for space heating.

   ii) Extensions over 95 Feet or where natural gas in not the primary fuel used for space heating – The Company may require cost participation if the estimated capital expenditure is not cost justified. The extension will be considered cost justified if the calculated Maximum Allowable Investment equals or exceeds the estimated capital expenditures using the following formula:

   Maximum Allowable Investment (MAI) =

   Annual Basic Service Charge +

   <u>(3rd Year Estimated Dk x Distribution Delivery Charge)</u>/LARR

   Where: LARR = 12.328%

   The LARR, defined as the Levelized Annual Revenue Requirement Factor, is the annual rate required to recover the present value of a project over the life of a project.

d) Cost of the extension shall include the gas main extension(s), valves, service line(s), cathodic protection equipment, 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.

e) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.

f) Contributions. In the event the extension is not cost justified, the customer(s) shall pay the Company the portion of the capital expenditures not cost justified. The extension will proceed if the customer:

    i) Pays in advance to the Company the excess amount not cost justified in cash, or

    ii) Agrees to pay a special monthly charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or

    iii) Agrees to pay annually a specified minimum charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or

    iv) Agrees to a combination of above methods, or

    v) Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.

FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105

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

vii) If within the five year period from the extension(s) in service date, the number of active customers and related volumes exceeds the projections used to determine MAI, the Company shall re-compute the contribution requirement by recalculating the MAI.

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

g) Refunds. Contributions for gas main extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension as additional customers are connected to the particular main extension for which the advance was made.

i) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements.

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

iii) 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.

iv) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.

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

i) Firm Gas Service Line Extensions:
The Company shall install gas service lines using the following general rules and regulations applicable to all firm gas service line extensions:

i) The term "service line" refers to facilities that are constructed from a main to the final terminus at a building or structure.

ii) The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premise(s).

iii) The Company will extend a service line to serve customer(s) where natural gas is the primary fuel used for space heating without charge up to, but not to exceed, 65 feet. The length of the service line shall be determined by measurement from the customer's property line to the stop valve on the service riser.

iv) If the additional service line required is beyond 65 feet or natural gas is not the primary fuel used for space heating, the Company may require cost participation if the estimated capital expenditure is not cost justified. The service line extension will be considered cost justified if the calculated MAI equals or exceeds the estimated capital expenditures using the MAI formula provided in ¶ c.ii.

v) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.

vi) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and materials rates.

A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $25.00 per meter for customers with gas input loads up to 400,000 BTU/hour; and $50.00 per meter for customers with gas input loads above 400,000 BTU/hour.

INTERRUPTIBLE GAS MAIN AND SERVICE LINE EXTENSIONS POLICY Rate 106

The Company will install gas main and service line extensions using the following guidelines:

a) Contribution. 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), cathodic protection equipment, regulators, meters (excluding remote data acquisition 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.

   i) The extension will proceed if the customer:

      (1) Pays in advance to the Company the total cost of construction, or

      (2) Customer may post a bond or irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.

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

   iii) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in the Company's Interruptible Gas Transportation Rates.

b) Refund. Contributions for gas main and service line extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension.

   i) 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, the Company shall refund the amount exceeding the revenue requirement on the following basis:

(1) Annually, beginning at the second (2nd) 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.

(2) Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements based on the above calculation.

(3) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.

ii) If within the five-year period from the extension(s) in service date, additional customers (firm or interruptible) are connected to an interruptible customer's main extension, the Company shall (1) determine the pro rata cost share applicable to the other customer (2) reduce the original customer's contribution requirement by the pro rata cost attributed to the new customer and (3) calculate an MAI for a firm customer through the process described in Rate 105 ¶ c.ii or collect the full amount for an interruptible customer. The amount collected will be subject to the applicable refund provisions for the remainder of the refund period.

c) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.

d) A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $100.00 for interruptible customers.

Montana-Dakota Utilities Co.
North Dakota Natural Gas

Tariffs - Proposed

Appendix B

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Fort Totten	Max	Steele
Barlow	Garrison	Medina	Surrey
Bismarck*	Glen Ullin	Milnor	Tappen
Burlington	Grafton	Minot	Turtle Lake
Carrington	Gwinner	New Rockford	Underwood
Cavalier	Jamestown	New Salem	Valley City
Cleveland	Kindred	Park River	Walhalla
Dawson	Langdon	Riverdale	Wahpeton
Des Lacs	Lincoln	Ruthville	Washburn
Devils Lake	Linton	Sandborn	Wilton
	Mandan	Sheyenne	Locations near Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	South Heart
Arnegard	Golva	Portal	Stanley
Beach	Hebron	Ray	Taylor
Belfield	Killdeer	Regent	Tioga
Berthold	Lefor	Rhame	Trenton
Bowman	Lignite	Richardton	Watford City
Dickinson*	Marmarth	Ross	Wheelock
East Fairview	Mott	Sentinel Butte	White Earth
Epping	New England	Springbrook	Williston

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

Montana-Dakota Utilities Co.

400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
25th Revised Sheet No. 3
Canceling 24th Revised Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery/Demand Charge	Rates 88 & 99 Cost of Gas	Total Rate/ Dk
Residential Rate 60	4				
Meters rated < 425 cubic feet		$0.921 per day	$0.438		
Meters rated > 425 cubic feet		$1.075 per day	$0.438		
Firm - Wahpeton Rate 62	5	$0.500 per day	$0.555		
Residential - Wahpeton Rate 63 1/	6				
Air Force Rate 64	7				
Minot Air Force Base		$4,000.00 per month			
PAR Site		$1,000.00 per month			
Firm Service			$1.355		
Interruptible Service - PAR			$0.991		
Interruptible Service - MAFB			$0.991		
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.88 per day	$1.382		
Meters rated > 500 cubic feet		$2.35 per day	$1.266		
Small Interruptible Gas Rate 71	14				
Maximum Rate per Dk		$450.00 per month	$0.659		
Minimum Rate per Dk		$450.00 per month	$0.102		
Optional Seasonal Gas Rate 72	15				
Meters rated < 500 cubic feet		$0.88 per day	$1.382		
Meters rated > 500 cubic feet		$2.35 per day	$1.266		
Firm General - Wahpeton Rate 73 1/	16				
Contracted Demand Service - Rate 74	17				
Meters rated < 500 cubic feet		$0.88 per day	$8.500	(Capacity Charge)	
Meters rated > 500 cubic feet		$2.35 per day	$8.500	(COG/Dk)	

1/ Service not available until (date of six months following the implementation of final rates) when customer's service will cease under Firm Service - Wahpeton Rate 62 and commence under the otherwsie Wahpeton-specific Montana-Dakota rate schedule.

Date Filed: November 1, 2023 **Effective Date:**

Issued By: Travis R. Jacobson
Director - Regulatory Affairs **Case No.:** PU-23-

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	Rate 89 Cost of Gas	Total Rate/ Dk
Transportation Service	24				
Small Interruptible Rate 81					
Maximum		$450.00 per month	$0.659		
Minimum			$0.102		
Large Interruptible Rate 82					
Maximum		$2,400.00 per month	$0.241		
Minimum			$0.061		
Large Interruptible Gas Rate 85	27				
Maximum Rate per Dk		$2,400.00 per month	$0.241		
Minimum Rate per Dk		$2,400.00 per month	$0.061		
Residential Rate 90	32				
Meters rated < 425 cubic feet		$0.921 per day	$0.438		
Meters rated > 425 cubic feet		$1.075 per day	$0.438		
Firm General Service Rate 92	13				
Meters rated < 500 cubic feet		$0.88 per day	$1.382		
Meters rated > 500 cubic feet		$2.35 per day	$1.266		

RATE SUMMARY SHEET

Miscellaneous Charges	Amount
Late Payment	1% per month
Returned Check	$15.00 per check
Manual Meter Reading Change	$26.05 per month
Reconnection charge after termination for nonpayment -During normal business hours -After normal business hours	 See Rate 100 paragraph 22 Current service labor rate per hour
Reconnection charge after termination for causes defined in Rate 100 paragraph 22 -During normal business hours -After normal business hours	 $30.00 Current service labor rate per hour
Reconnection charge applicable to seasonal or temporary customers -During normal business hours -After normal business hours	 Minimum- $30.00 (See Rate 100 § V 21) Minimum- Current service labor rate per hour
Reconnection charge applicable to transportation customers when remote data acquisition equipment must be reinstalled	$160.00

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses, excluding the community of Wahpeton where service is provided under Firm Gas Service – Wahpeton Rate 62 or Residential Gas Service – Wahpeton – Rate 63. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:

For customers with meters rated under 425 cubic feet per hour	$0.921 per day
For customer with meters rated over 425 cubic feet per hour or whose service has elevated pressure	$1.075 per day
Distribution Delivery Charge:	$0.438 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.

General Terms and Conditions:

1. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

FIRM GAS SERVICE – WAHPETON Rate 62

Availability:

Service under this rate schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota. Gas service under this rate schedule will cease six months following implementation of final rates in Case No. PU-23-___, or [date], at which time each customer's service will be re-classified as either Residential Gas Service – Wahpeton Rate 63 or Firm General Gas Service – Wahpeton Rate 73, dependent on each customer's service and as defined in Rate 100, §V.3.

Rate 62 customers will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk

For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023

Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

FIRM GAS SERVICE – WAHPETON Rate 62

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI Wahpeton pipeline expansion project are required to take service under the applicable rates defined herein.

2. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

For the community of Wahpeton, North Dakota for all domestic uses. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

1. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:

Minot Air Force Base	$4,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$1,000.00 per month

Distribution Delivery Charge:

Firm Service	$1.355 per dk
Interruptible Service	$0.991 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

Availability:

In all communities served for all purposes except for resale and excluding the community of Wahpeton where service is provided under Firm Gas Service – Wahpeton Rate 62 or Firm General Gas Service – Wahpeton Rate 73. See Rate 100, §3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$0.88 per day
Distribution Delivery Charge:	$1.382 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served, including the community of Wahpeton. For all interruptible 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 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 billed at Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate 71 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

Basic Service Charge:	$450.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.659 per dk	$0.102 per dk

Cost of Gas: Determined Monthly- See Rate Summary Sheet for Current Rate

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. 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 charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, including the community of Wahpeton, and for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate 72 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$0.88 per day
Distribution Delivery Charge:	$1.382 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.

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.13, or any amendments or alterations thereto.

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Cost of Gas:

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

General Terms and Conditions:

1. The 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 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE – WAHPETON Rate 73

Availability:

For the community of Wahpeton, North Dakota for all purposes, except for resale. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk
For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI pipeline expansion project are required to take service under the applicable rates defined herein.

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

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served, including the community of Wahpeton. Applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate 74 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.88 per day
For customers with meters rated over 500 cubic feet per hour	$2.35 per day
Distribution Demand Charge:	$8.50 per dk per month of billing demand
Capacity Charge per Monthly Demand dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Commodity Cost of Gas per dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to meter installation.

General Terms and Conditions:

1. Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable for a minimum period of one year.

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

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

GWINNER PIPELINE CAPACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Gas Service Extension Policy Rate 120.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through 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 by the Company.

Rate 81 or 82 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

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 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer.

<u>Large Interruptible General Gas Transportation Service Rate 82:</u>
Transportation service is available for all general gas service customers whose interruptible natural gas load 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, on an interruptible basis, pursuant to 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer.

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:

Rate 81	$ 450.00 per month
Rate 82	$2,400.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$0.659	$0.241
Minimum Rate per dk	$0.102	$0.061

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. The 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:
   a. To qualify for gas transportation service a 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.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. 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. The 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 the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – 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.11.

5. 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 charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

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

   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.21.

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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, including the community of Wahpeton. For all interruptible general gas service customers whose interruptible natural gas load 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 billed at Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate 85 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

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:	$2,400.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$0.241 per dk	$0.061 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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 Service Rates 60 and 90 and Firm General Service Rates 70 and 92 shall be subject to decreases or increases under the DDSM.

Distribution Delivery Stabilization Mechanism:

A DDSM will be determined for each customer taking service under Residential Service Rates 60 and 90 and Firm General Service Rates 70 and 92 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 Service Rates 60 and 90 and Firm General Services Rate 70 or 92. 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.

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

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 60, 70, 90 or 92
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	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	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 Service Rate 60 = 0.04087 Residential Service Rate 90 = 0.01039 Firm General Service Rate 70 Small = 0.04138 Firm General Service Rate 70 Large = 0.81272 Firm General Service Rate 92 Small = 0.03429 Firm General Service Rate 92 Large = 1.76785
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to firm service Rates 60, 62, 63, 70, 72, 73, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service Rates 71 and 85 as established in Case No. PU-13-803, including prior period over or under collected balances.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:

For customers with meters rated under 425 cubic feet per hour	$0.921 per day
For customers with meters rated over 425 cubic feet per hour or whose service has elevated pressure	$1.075 per day

Distribution Delivery Charge: $0.438 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

Date Filed: November 1, 2023 **Effective Date:**

Issued By: Travis R. Jacobson
Director – Regulatory Affairs **Case No.:** PU-23-

RESIDENTIAL PROPANE SERVICE Rate 90

General Terms and Conditions:

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

FIRM GENERAL PROPANE SERVICE Rate 92

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

For customers with meters rated
under 500 cubic feet per hour

Basic Service Charge:	$0.88 per day
Distribution Delivery Charge:	$1.382 per dk

For customers with meters rated
over 500 cubic feet per hour

Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

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CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly provided for 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 Company's meter(s) located on customer's premises.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

GAS DAY – Means a period of twenty-four 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 Company.

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

PIPELINE – The transmission company(s) delivering natural gas into Company's system.

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, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

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

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A 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 the customer desiring the service. The Company may refuse a customer or terminate service to a 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. The 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 by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 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 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

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

11. 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, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

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 the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

   a. In the event the Company needs to turn a customer's gas meter on, and a customer's equipment needs to be restarted, the customer may consent to, and accept responsibility for, the relighting of any pilot lights on equipment on customer's side of the meter. If verbal consent of customer is given at the time of scheduling the gas meter turn on, Company personnel will turn gas meter on and inspect for gas use. If no gas use is detected at that time, the gas meter will be left on and the customer can relight any pilot lights on equipment on customer's side of the meter at their convenience. If gas use is detected, Company personnel will turn gas meter off and advise customer to have their system checked. The Company will only turn the gas meter on after customer's system has been checked and no gas use is detected.

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, or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold 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. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from Company's negligent or wrongful acts under and during 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 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 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 authorization 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 the 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 twelve months unless there is a material change in the 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: separately metered units, such as single private residences, single apartments, mobile homes with separate meters and sorority and fraternity houses. In addition,

auxiliary buildings on the same premise as the living quarters when used for residential purposes may be served on the residential rate. 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, boarding houses, hotels, service garages, wholesale houses, filling stations, barber shops, beauty salons, master metered 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), the customer will be billed under the predominate use policy. Under this policy, the customer's combined service is billed under the rate (Residential or Nonresidential) applicable to the type of service which constitutes 50% or more of the 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 on the Nonresidential rates.

4. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. 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 regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 –

Manufactured Homes Construction and Safety Standards) Subpart 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.

6. CONSUMER DEPOSITS – The Company will determine whether or not a deposit shall be required of an applicant for gas service in accordance with the following criteria:
   (a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.

   (b) The Company may accept in lieu of a cash deposit a contract signed by a guarantor, satisfactory to the Company, whereby the payment of a specified sum not to exceed the required cash deposit is guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.

   A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business day of each year. Interest shall be credited to the 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 twelve months, provided prompt payment record has been established.

7. METERING AND MEASUREMENT:
   (a) Company will meter the volume of natural gas delivered to customer at the delivery point. Such meter measurement will be conclusive upon both

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 AGA-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.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
    (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60, 90, or a Wahpeton residential customer, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

    (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60, 90, or a Wahpeton residential customer), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

    (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1 percent per month will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's financial institution.

15. MANUAL METER READING CHARGE– A monthly Manual Meter Reading Charge of $26.05 per month will be assessed customer(s) who have requested, and received Company approval, to have their meter read manually each month in lieu of an AMR-equipped meter read. Customer(s) agree to contract for the manual reading of the meter for a minimum period of one year.

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

17. UTILITY CUSTOMER SERVICES:
  (a) The following services will be performed at no charge regardless of the time of performance:
    (1) Fire and explosions calls.

    (2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

    (3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

    (4) Maintenance or repair of Company-owned facilities on the customer's premises.

    (5) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

  (b) The following service calls will be performed at no charge during the Company's normal business hours:
    (1) Cut-ins and cut-outs.

    (2) High bills or inadequate service complaints.

    (3) Location of underground Company facilities for contractors, builders, plumbers, etc.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

    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.

    To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. local time on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. local time on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

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

20. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

    Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours. The Capacity Reservation Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

    Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General Rate 70 = 171 dk; Large Firm General Rate 70 = 1,217 dk; Small Firm General Propane Rate 92 = 175 dk; Large Firm General Propane Rate 92 = 1,919 dk; and Small Interruptible Rate 71 = 7,301 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours. The Capacity Reservation

Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

Wahpeton Sales Customers – Customers will be charged a reconnection fee of $30.00.

Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by 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 of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. local time on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

23. DISCONNECTION 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 the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

(b) In the event that there has been unauthorized use of service, customer shall be charged for:
   (1) Time, material and transportation costs used in investigation.
   (2) Estimated charge for non-metered gas.
   (3) On-premise time to correct situation.
   (4) Any damage to Company property.
   (5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
   Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
   (1) All delinquent bills, if any.
   (2) The amount of any Company revenue loss attributable to said tampering.
   (3) 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 number 20.b above.
   (4) Reconnection fee applicable.
   (5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

25. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

26. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
    Rate 120 – Gas Service Extension Policy
    Rate 124 – Replacement, Relocation and Repair of Gas Service Lines

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

   a. A meter for which the sample is satisfactory will remain in service.

   b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

   c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

      i. If evaluation determines the group is homogeneous, then the entire group will be removed.

      ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting

Montana-Dakota shall file reports of its meter test results by April 1 of the year following the test period. The test year shall run from July 1 through June 30.

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.
   a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

SUMMARY BILLING PLAN Rate 115

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
    a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

REPLACEMENT, RELOCATION
AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

3. 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 the Gas Service Extension Policy - Rate 120.

Tariffs Reflecting Proposed Changes

TABLE OF CONTENTS

COMMUNITIES SERVED

NATURAL GAS SERVICE

Dakota Heartland Region

Apple Valley	Fort Totten	Max	Steele
Barlow	Garrison	Medina	Surrey
Bismarck*	Glen Ullin	Milnor	Tappen
Burlington	Grafton	Minot	Turtle Lake
Carrington	Gwinner	New Rockford	Underwood
Cavalier	Jamestown	New Salem	Valley City
Cleveland	Kindred	Park River	Walhalla
Dawson	Langdon	Riverdale	Wahpeton
Des Lacs	Lincoln	Ruthville	Washburn
Devils Lake	Linton	Sandborn	Wilton
	Mandan	Sheyenne	Locations near Hankinson/Fairmont

Badlands Region

Alexander	Gladstone	Palermo	South Heart
Arnegard	Golva	Portal	Stanley
Beach	Hebron	Ray	Taylor
Belfield	Killdeer	Regent	Tioga
Berthold	Lefor	Rhame	Trenton
Bowman	Lignite	Richardton	Watford City
Dickinson*	Marmarth	Ross	Wheelock
East Fairview	Mott	Sentinel Butte	White Earth
Epping	New England	Springbrook	Williston

PROPANE SERVICE

Badlands Region

Hettinger

*Designates Region Office

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RESIDENTIAL GAS SERVICE Rate 60

Availability:

In all communities served for all domestic uses, excluding the community of Wahpeton where service is provided under Firm Gas Service – Wahpeton Rate 62 or Residential Gas Service – Wahpeton – Rate 63. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	~~$0.8244 per day~~
For customers with meters rated under 425 cubic feet per hour	$0.921 per day
For customer with meters rated over 425 cubic feet per hour or whose service has elevated pressure	$1.075 per day
Distribution Delivery Charge:	$0.438 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.

General Terms and Conditions:

1. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

~~1~~2. The foregoing schedule is subject to Rates 100 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GAS SERVICE – WAHPETON Rate 62

Availability:

Service under this rate schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota. Gas service under this rate schedule will cease six months following implementation of final rates in Case No. PU-23-____, or [date], at which time each customer's service will be re-classified as either Residential Gas Service – Wahpeton Rate 63 or Firm General Gas Service – Wahpeton Rate 73, dependent on each customer's service and as defined in Rate 100, §V.3.

Rate 62 customers will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk
For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

FIRM GAS SERVICE – WAHPETON Rate 62

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI Wahpeton pipeline expansion project are required to take service under the applicable rates defined herein.

2. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

For the community of Wahpeton, North Dakota for all domestic uses. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

1. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

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

Availability:

Minot Air Force Base near Minot, North Dakota, and the Perimeter Acquisition Radar (PAR) Site, near Concrete, North Dakota. The Air Force shall make an election of its requirements under each available service and such requirements shall be set forth in a service agreement with the Company.

Rate:

Basic Service Charge:	
Minot Air Force Base	$~~2,000.00~~4,000.00 per month
Perimeter Acquisition Radar (PAR) Site	$~~175.00~~1,000.00 per month
Distribution Delivery Charge:	
Firm Service	$~~0.449~~1.355 per dk
Interruptible Service	$~~0.255~~0.991 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GENERAL GAS SERVICE Rate 70

Availability:
In all communities served for all purposes except for resale~~.~~ and excluding the community of Wahpeton where service is provided under Firm Gas Service – Wahpeton Rate 62 or Firm General Gas Service – Wahpeton Rate 73. See Rate 100, §3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour

Basic Service Charge:	$~~0.75~~0.88 per day
Distribution Delivery Charge:	$~~1.174~~1.382 per dk

For customers with meters rated over 500 cubic feet per hour

Basic Service Charge:	$~~2.13~~2.35 per day
Distribution Delivery Charge:	$~~0.917~~1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:
The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas 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.

SMALL INTERRUPTIBLE GENERAL GAS SERVICE Rate 71

Availability:

In all communities served, including the community of Wahpeton. ~~f~~For all interruptible 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 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 billed at Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate 71 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

Basic Service Charge:	$450.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$~~0.566~~0.659 per dk	$0.102 per dk
Cost of Gas:	Determined Monthly- See Rate Summary Sheet for Current Rate	

The Distribution Delivery Charge shall be set forth in the service agreement required as provided in the General Terms and Conditions for service. Such rate, as adjusted to reflect changes in the Cost of Gas, shall apply for the term of the agreement regardless of a change in the rates set forth above.

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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. 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 charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

Availability:

In all communities served, including the community of Wahpeton, and for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate 72 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$~~0.75~~0.88 per day
Distribution Delivery Charge:	$~~1.174~~1.382 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$~~2.13~~2.35 per day
Distribution Delivery Charge:	$~~0.917~~1.266 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.

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.13, or any amendments or alterations thereto.

Cost of Gas:

OPTIONAL SEASONAL GENERAL GAS SERVICE Rate 72

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

~~FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74~~

~~Availability:~~

~~In all communities served applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.~~

~~Rate:~~

~~Basic Service Charge:~~

~~For customers with meters rated under 500 cubic feet per hour~~	~~$0.75 per day~~
~~For customers with meters rated over 500 cubic feet per hour~~	~~$2.13 per day~~
~~Distribution Demand Charge:~~	~~$8.00 per dk per month of billing demand~~
~~Capacity Charge per Monthly Demand dk:~~	~~Determined Monthly – See Rate Summary Sheet for Current Rate~~
~~Cost of Gas: Commodity per dk:~~	~~Determined Monthly – See Rate Summary Sheet for Current Rate~~

~~Minimum Bill:~~

~~Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.~~

~~Determination of Monthly Billing Demand:~~

~~Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.~~

~~**Cost of Gas:**~~

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

~~**Metering Requirements:**~~

1. ~~Service provided for under tariff must be separately metered from customer's other gas services.~~

2. ~~Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.~~

3. ~~Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.~~

4. ~~Consultation between the customer and the Company regarding telemetering requirements shall occur prior to meter installation.~~

~~**General Terms and Conditions:**~~

1. ~~Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable for a minimum period of one year.~~

1. ~~The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the stat~~

FIRM GENERAL GAS SERVICE – WAHPETON Rate 73

Availability:

For the community of Wahpeton, North Dakota for all purposes, except for resale. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk
For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

FIRM GENERAL GAS SERVICE – WAHPETON Rate 73

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI pipeline expansion project are required to take service under the applicable rates defined herein.

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

~~GWINNER PIPELINE CAPACITY RESERVATION CHARGE Rate 75~~

~~Availability:~~

~~To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).~~

~~Applicability:~~

~~Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.~~

~~Capacity Reservation Charge:~~

~~Residential Customers provided Service Under Rate 60~~	~~$0.8712 per day~~
~~All other Customers~~	~~$26.50 per maximum daily quantity reservation~~

~~Minimum Bill:~~

~~Capacity Reservation 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.13, or any amendments or alterations thereto.~~

~~Determination of Monthly Billing Demand:~~

~~As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.~~

~~Montana-Dakota Utilities Co.~~
~~400 N 4th Street~~
~~Bismarck, ND 58501~~

~~General Terms and Conditions:~~

~~1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.~~

~~2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.~~

~~3. Any main or service line extension necessary to provide service to the Customer shall be subject to the Firm Gas Service Extension Policy Rate 120 or Interruptible Service Extension Policy Rate 119.~~

~~The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served, including the community of Wahpeton. Applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate 74 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

Rate:

Basic Service Charge:	
For customers with meters rated under 500 cubic feet per hour	$0.88 per day
For customers with meters rated over 500 cubic feet per hour	$2.35 per day
Distribution Demand Charge:	$8.50 per dk per month of billing demand
Capacity Charge per Monthly Demand dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Commodity Cost of Gas per dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Cost of Gas:

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

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to meter installation.

General Terms and Conditions:

1. Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable for a minimum period of one year.

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

GWINNER PIPELINE CAPACITY RESERVATION CHARGE Rate 75

Availability:

To customers provided natural gas service either directly or through another connection with the Company's pipeline interconnecting with the Alliance Pipeline near Milnor, North Dakota and running through Ransom and Sargent Counties to the Bobcat Company's facility located near Gwinner, North Dakota (Gwinner Pipeline).

Applicability:

Customers requesting natural gas service where service must be provided off the Gwinner Pipeline shall contract for capacity required to serve their annual requirements. The Reservation Charge shall be in addition to all other charges applicable under the otherwise applicable rate schedule 60, 70, 71, 72, 74, 81, 82, or 85.

Capacity Reservation Charge:

Residential Customers provided Service Under Rate 60	$0.8712 per day
All other Customers	$26.50 per maximum daily quantity reservation

Minimum Bill:

Capacity Reservation 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.13, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract except for residential customers that will be assessed the daily charge above. All other customers will specify a contract quantity based on the maximum daily quantity required. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

GWINNER PIPELINE CAPACITY RESERVATION CHARGE Rate 75

General Terms and Conditions:

1. The customer agrees to contract for service under the Gwinner Pipeline Capacity Reservation Charge Rate 75 for a minimum period of one year.

2. Service under any other rate schedule is not available to customers served through the Gwinner Pipeline without a reservation for capacity on the Gwinner Pipeline.

3. Any main or service line extension necessary to provide service to the Customer shall be subject to the ~~Firm~~ Gas Service Extension Policy Rate 120 ~~or Interruptible Service Extension Policy Rate 119~~.

4. The foregoing schedule is subject to the requirements set forth under the otherwise applicable rate schedule for natural gas service and Rates 100 through 124, including any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability:

This service is applicable for transportation of natural gas to customer's premise (metered at a single delivery point) through 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 by the Company.

Rate 81 or 82 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

The transportation services are as follows:

Small Interruptible General Gas Transportation Service Rate 81:
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 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer.

Large Interruptible General Gas Transportation Service Rate 82:
Transportation service is available for all general gas service customers whose interruptible natural gas load 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, on an interruptible basis, pursuant to 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer.

Rate:

Under Rate 81 or 82, customer shall pay the applicable Basic Service Charge plus a negotiated rate not more than the maximum rate or less than the minimum rate specified below. In the event customer also takes service under Rate 71 or Rate 85, the Basic Service Charge applicable under Rate 81 or Rate 82 shall be waived.

Basic Service Charge:	
Rate 81	$450.00 per month
Rate 82	$~~1,600.00~~2,400.00 per month

	Rate 81	Rate 82
Maximum Rate per dk	$~~0.566~~0.659	$~~0.237~~0.241
Minimum Rate per dk	$0.102	$0.061

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. The 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:
   a. To qualify for gas transportation service a 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.

   b. Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.

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 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 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. 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. The 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 the customer receives only gas transportation service in any billing period).

4. PRIORITY OF SERVICE – 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.11.

5. 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 charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

6. CUSTOMER USE OF NON-DELIVERED VOLUMES - In the event the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 9.b. Gas volumes supplied by Company will be charged at charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge). The Company is under no obligation to notify customer of non-delivered volumes.

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

   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.21.

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

LARGE INTERRUPTIBLE GENERAL GAS SERVICE Rate 85

Availability:

In all communities served, including the community of Wahpeton. ~~f~~For all interruptible general gas service customers whose interruptible natural gas load 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 billed at Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer. For interruption purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Rate 85 customers in Wahpeton will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates]. Following [date six months following implementation of rates], a Montana-Dakota account will be established and customer will start receiving a Montana-Dakota gas bill.

This rate schedule shall not apply for service to U.S. Government installations, which are covered by separate special contracts.

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:	$~~1,600.00~~2,400.00 per month	
Distribution Delivery Charge:	Maximum	Minimum
	$~~0.237~~0.241 per dk	$0.061 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

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 the Company's firm gas service rates, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.

2. PENALTY FOR FAILURE TO CURTAIL OR INTERRUPT – If customer fails to curtain or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the charges applicable under Firm General Gas Service Rate 70 or either Firm Gas Service Rate 62 or Firm General Gas Service Rate 73 if a Wahpeton customer (excluding Basic Service Charge), 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.

3. AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 90 days prior to the end of the initial term. Absent execution of such termination notice, the agreement shall continue for additional terms of equal length until written notice is given as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.

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 Service Rates 60 and 90 and Firm General Service Rates 70 and 92 shall be subject to decreases or increases under the DDSM.

Distribution Delivery Stabilization Mechanism:

A DDSM will be determined for each customer taking service under Residential Service Rates 60 and 90 and Firm General Service Rates 70 and 92 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 Service Rates 60 and 90 and Firm General Services Rate 70 or 92. 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, 70, 90 or 92
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	-	The deviation between the average daily temperatures and 60 degrees Fahrenheit.
Normal Degree Days	-	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 Service Rate 60 = 0.04087 Residential Service Rate 90 = 0.01039 Firm General Service Rate ~~Code~~ 70~~0~~ Small = ~~0.05012~~0.04138 Firm General Service Rate ~~Code~~ 70~~1~~ Large = ~~0.90499~~0.81272 Firm General Service Rate ~~Code~~ 92~~0~~ Small = ~~0.04802~~0.03429 Firm General Service Rate ~~Code~~ 92~~1~~ Large = ~~1.79780~~1.76785
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota.

Each month, Account 191 shall be debited (if the balance in said account is a debit balance) and shall be credited (if the balance in said account is a credit balance) for a carrying charge; which shall be the product of (i) and (ii) below:

(i) The balance in Account 191 as of the end of the immediately preceding month, exclusive of carrying charges accrued pursuant to this Subsection (b)(2) and net of the related deferred tax amounts in Accounts 283 or 190, as appropriate.

(ii) One-twelfth of the annual interest rate as set forth in this Subsection (b)(2). The carrying charges shall be accrued in a supplementary Account 191 for each rate schedule, and carrying charges shall not be computed on the amounts in such supplementary account.

(c) Reduction of Amounts in Account 191:

(1) The amounts in Account 191 shall be decreased each month by an amount determined by multiplying the currently effective surcharge adjustment included in rates for that month (as calculated in Section 4) by the dks sold during that month under each rate schedule. The account shall be increased in the event the adjustment is a negative amount.

(2) The amount amortized each month shall be applied pro rata between the amounts in Account 191 specified in Subsections 5(a)(1), (2), (3) and (5) and the amounts in the supplementary Account 191 specified in Subsection 5(a)(4).

6. Grain Drying Margin Sharing Mechanism:
At the time of each surcharge adjustment, pursuant to Paragraph 4, the Company will compute a credit to firm service Rates 60, 62, 63, 70, 72, 73, and 74 based on 90 percent of the margin revenues collected from Grain Drying customers served under interruptible service ~~r~~Rates 71 and 85 as established in Case No. PU-13-803, including prior period over or under collected balances.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RESIDENTIAL PROPANE SERVICE Rate 90

Availability:

For the community of Hettinger for all domestic purposes. See Rate 100, §V.3, for definition on class of service.

Rate:

Basic Service Charge:	~~$0.8244 per day~~
For customers with meters rated under 425 cubic feet per hour	$0.921 per day
For customers with meters rated over 425 cubic feet per hour or whose service has elevated pressure	$1.075 per day
Distribution Delivery Charge:	$0.438 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of gas as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

General Terms and Conditions:

Date Filed: November 1, 2023 **Effective Date:**

Issued By: Travis R. Jacobson
Director – Regulatory Affairs **Case No.:** PU-23-

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Scheduling

RESIDENTIAL PROPANE SERVICE Rate 90

1. The Company may at its discretion and upon thirty days notice, disconnect service to a customer utilizing a second source of propane. Any customer so disconnected shall not be eligible for service hereunder for one year from date of disconnection and shall be subject to reconnection charges to restore service after the one-year period.

2. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

~~2.~~3. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability:

For the community of Hettinger for all purposes except for resale. See Rate 100, §V.3, for definition on class of service.

Rate:

For customers with meters rated under 500 cubic feet per hour	
Basic Service Charge:	$~~0.75~~0.88 per day
Distribution Delivery Charge:	$~~1.174~~1.382 per dk
For customers with meters rated over 500 cubic feet per hour	
Basic Service Charge:	$~~2.13~~2.35 per day
Distribution Delivery Charge:	$~~0.917~~1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

The cost of propane as defined in Cost of Gas - Propane Rate 99 or any amendments or alterations thereto. The cost of propane 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.

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CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by Company at one location and at one point of delivery unless otherwise expressly provided for 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 Company's meter(s) located on customer's premises.

EXCESS FLOW VALVE – Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.

GAS DAY – Means a period of twenty-four 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 Company.

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

PIPELINE – The transmission company(s) delivering natural gas into Company's system.

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, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, toll, rental or classification.

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

SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.

III. **CUSTOMER OBLIGATION:**

1. APPLICATION FOR SERVICE – A 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 the customer desiring the service. The Company may refuse a customer or terminate service to a 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. The 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 by the Company.

2. SERVICE AVAILABILITY – Gas will normally be delivered at standard pressures of four to six ounces, dependent on the service territory where the gas service is being delivered. Delivery of gas service at pressures greater than the standard operating pressure may be available and will require a consultation with the Company to determine availability.

3. 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 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 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

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

11. 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, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.

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 the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on the customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues and appliances on the customer's side of the point of delivery.

   a. In the event the Company needs to turn a customer's gas meter on, and a customer's equipment needs to be restarted, the customer may consent to, and accept responsibility for, the relighting of any pilot lights on equipment on customer's side of the meter. If verbal consent of customer is given at the time of scheduling the gas meter turn on, Company personnel will turn gas meter on and inspect for gas use. If no gas use is detected at that time, the gas meter will be left on and the customer can relight any pilot lights on equipment on customer's side of the meter at their convenience. If gas use is detected, Company personnel will turn gas meter off and advise customer to have their system checked. The Company will only turn the gas meter on after customer's system has been checked and no gas use is detected.

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, or devices on the customer's premises, except loss, injuries, death, or damages resulting from the negligence of the Company.

4. INDEMNIFICATION – Customer agrees to indemnify and hold 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. Company agrees to indemnify and hold customer harmless from any and all

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 AGA-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.

Local sales base pressure is defined as four to six ounces (depending on service area) per square inch gauge pressure plus local average atmospheric pressure.

10. BILLING ADJUSTMENTS –
   (a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

   (b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as Residential Service Rates 60, ~~or~~ 90, or a Wahpeton residential customer, the Company may adjust back and rebill the bills in error for a period not to exceed six months.

   (c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service is identified as non-residential (gas service provided under all rate schedules other than Rates 60, ~~or~~ 90, or a Wahpeton residential customer), the Company may adjustment back and rebill the bills in error for a period not to exceed six years.

   (d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and

12. EXCESS FLOW VALVE – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.

13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill. An amount equal to 1 percent per month will be applied to any past due balance, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.

14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for any check for any reason not honored by customer's ~~bank~~financial institution.

15. MANUAL METER READING CHARGE– A monthly Manual Meter Reading Charge of $26.05 per month will be assessed customer(s) who have requested, and received Company approval, to have their meter read manually each month in lieu of an AMR-equipped meter read. Customer(s) agree to contract for the manual reading of the meter for a minimum period of one year.

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

17. UTILITY CUSTOMER SERVICES:
   (a) The following services will be performed at no charge regardless of the time of performance:
      (1) Fire and explosions calls.

      (2) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

      (3) Investigate hazardous condition on customer premises, such as gas leaks, odor complaints, combustion gas fumes.

      (4) Maintenance or repair of Company-owned facilities on the customer's premises.

      (5) Pilot relights necessary due to an interruption in gas service deemed to be the Company's responsibility.

   (b) The following service calls will be performed at no charge during the Company's normal business hours:
      (1) Cut-ins and cut-outs.

      (2) High bills or inadequate service complaints.

      (3) Location of underground Company facilities for contractors, builders, plumbers, etc.

18. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS – For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.

   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.

   To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. local time on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. local time on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

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

20. INSTALLING TEMPORARY METERING FACILITIES OR SERVICE – A customer requesting a temporary meter installation and service will be charged on the basis of direct costs incurred by the Company.

21. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER – A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee as follows:

    Residential - The Basic Service Charge applicable during the period service was not being used and a charge of $30.00. The minimum will be based on standard overtime rates for reconnecting service after normal business hours. The Capacity Reservation Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

    Non-Residential – The Basic Service Charge applicable during the period while service was not being used. However, the reconnection charge applicable to seasonal business concerns such as irrigation, swimming facilities, grain drying and asphalt processing shall be the Basic Service Charge applicable during the period while service was not being used less the Distribution Delivery Charge revenue collected during the period in-service for usage above the annual authorized usage by rate class (Small Firm General Rate 70 = ~~174~~171 dk; Large Firm General Rate 70 = ~~1,220~~1,217 dk; Small Firm General Propane Rate 92 = ~~170~~175 dk; Large Firm General Propane Rate 92 = ~~1,898~~1,919 dk; and Small Interruptible Rate 71 = ~~5,918~~7,301 dk). A reconnection fee of $30.00 will also apply to reconnections. The minimum will be based on standard overtime rates for reconnecting service occurring after normal business hours. The Capacity Reservation

Charge under Gwinner Pipeline Reservation Charge Rate 75 will also be applicable during the period service was not being used, if the Capacity Reservation Charge is applicable to the customer while in service.

Wahpeton Sales Customers – Customers will be charged a reconnection fee of $30.00.

Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required remote data acquisition equipment is necessary.

22. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by 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 of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. local time on a regular work day, customers will be advised that over time service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.

23. DISCONNECTION 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 the customer to fulfill the contractual obligations imposed as conditions of obtaining service.

(b) In the event that there has been unauthorized use of service, customer shall be charged for:
(1) Time, material and transportation costs used in investigation.
(2) Estimated charge for non-metered gas.
(3) On-premise time to correct situation.
(4) Any damage to Company property.
(5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.

(c) Reconnection of Service:
Gas service disconnected for any of the above reasons shall be reconnected after a customer has furnished satisfactory evidence of compliance with the Company's rules and conditions of service, and paid any service charges which are due, including:
(1) All delinquent bills, if any.
(2) The amount of any Company revenue loss attributable to said tampering.
(3) 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 number 20.b above.
(4) Reconnection fee applicable.
(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.

25. BILL DISCOUNT FOR QUALIFYING EMPLOYEES – A bill discount may be available for residential use only in a single family unit served by Montana-Dakota to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at applicable rate and the amount reduced by 33 1/3 percent.

26. SEE ALSO THE FOLLOWING RATES FOR SPECIAL PROVISIONS:
~~Rate 119 – Interruptible Gas Service Extension Policy~~
Rate 120 – ~~Firm~~ Gas Service Extension Policy
Rate 124 – Replacement, Relocation and Repair of Gas Service Lines

5. The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.

6. Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable quality level of 15%. The following actions will be taken based on the test results:

    a. A meter for which the sample is satisfactory will remain in service.

    b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.

    c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% of the sample registers over 102%

        i. If evaluation determines the group is homogeneous, then the entire group will be removed.

        ii. If group is not homogeneous and a subset of the group is found defective, that subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.

Reporting

Montana-Dakota shall file reports of its meter test results by ~~December~~April 1 ~~for the meter testing conducted between June 30 of the previous year and July 1~~of the year following the test period. The test year shall run from July 1 through June 30.

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.
    a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

SUMMARY BILLING PLAN Rate 115

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
    a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

REPLACEMENT, RELOCATION
AND REPAIR OF GAS SERVICE LINES Rate 124

1. 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.), the customer shall be charged for on the basis of direct costs incurred by the Company.

2. 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 on a direct cost basis. If the damage was caused by independent contractors, not in the employ of the customer, the charges shall be billed directly to such contractor.

3. 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 the ~~Firm~~ Gas Service Extension Policy - Rate 120.

Great Plains Natural Gas Co.
North Dakota Gas Tariffs –

Reflecting Proposed Changes

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~~GREAT PLAINS NATURAL GAS CO.~~
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~~RATE SUMMARY SHEET~~ ~~Canceling 202nd Revised Sheet No.1.1~~
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~~Rate Schedule~~	~~Sheet No.~~	~~Basic Service Charge~~	~~Distribution Delivery Charge~~	~~COG Items~~	~~Total Rate/dk~~
~~Firm Gas Service - General Rate 65~~	~~2~~	~~$0.250 per day~~	~~$0.9220 per dk~~	~~$3.9186~~	~~$4.8406~~
~~Interruptible Gas Service - General Rate 71~~	~~3~~	~~$180.00 per month~~	~~(Maximum)~~ ~~$0.6690 per dk~~	~~$3.3222~~	~~(Maximum)~~ ~~$3.9912~~
~~Transportation Service Rate 80~~	~~5~~	~~$180.00 per month~~	~~(Maximum)~~ ~~$0.6690 per dk~~		~~(Maximum)~~ ~~$0.6690~~

FIRM GAS SERVICE – GENERAL Rate 65

Availability:

Service under this schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota whose maximum requirements are not more than 2,000 cubic feet per hour. See Rate 100 §III.2 for availability of firm gas service. Service under this rate shall not be subject to curtailment or interruption.

Rate:

Basic Service Charge:	$0.250 per day
Distribution Delivery Charge:	$0.922 per dk
Cost of Gas:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge.

Cost of Gas:

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

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.13, or any amendments or alterations thereto.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

~~GREAT PLAINS NATURAL GAS CO.~~

~~A Division of Montana-Dakota Utilities Co.~~

~~State of North Dakota~~
~~Gas Rate Schedule~~

~~NDPSC Volume 2~~
~~5th Revised Sheet No. 3~~
~~Canceling 4th Revised Sheet No. 3~~

~~INTERRUPTIBLE GAS SERVICE – GENERAL Rate 71~~

~~Availability:~~

~~Service under this schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. The rates herein are applicable only to customer's interruptible load. Customer's firm natural gas requirements must be separately metered or specified in firm service agreement. The firm service volumes are subject to available capacity. Customer's firm load shall be billed at Firm Gas Service – General Rate 65. For interruptible purposes, the maximum daily firm requirements shall be set forth in the firm service agreement.~~

~~Rate:~~

~~Basic Service Charge:~~	~~$180.00 per month~~
~~Distribution Delivery Charge:~~	
~~Maximum~~	~~$0.669 per dk~~
~~Minimum~~	~~$0.130 per dk~~
~~Cost of Gas:~~	~~Determined Monthly – See Rate Summary Sheet for Current Rate~~

~~Minimum Bill:~~

~~Basic Service Charge~~

~~Cost of Gas:~~

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

~~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.13, or any amendments or alterations thereto.~~

~~Date Filed:~~	~~May 7, 2021~~	**~~Effective Date:~~**	~~Service rendered on and after June 1, 2021~~
~~Issued By:~~	~~Travis R. Jacobson~~ ~~Director – Regulatory Affairs~~	**~~Case No.:~~**	~~PU-20-379~~

~~**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 the Company's firm general gas service rate, and the Company shall have the right to interrupt deliveries to customers under this schedule without being required to give previous notice of intention to so interrupt whenever, in 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 the provisions of Rate 100, §V.11.~~

2. ~~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 Gas Service – General Rate 65 (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.~~

3. ~~AGREEMENT – Customer will be required to enter into an agreement for service hereunder for a minimum term of 12 months. Written notice of termination by either Company or customer must be given at least 60 days prior to the end of the initial term. Absent such termination notice, the agreement shall continue for additional terms of equal length until written notice is given, as provided herein, prior to the end of any subsequent term. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under this rate or another appropriate rate schedule for the customer's operations.~~

4. ~~OBLIGATION TO NOTIFY COMPANY OF CHANGE IN DAILY OPERATIONS – Customer will be required as specified in the service agreement to notify 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 the customer equal to the penalty amounts Company must pay to the interconnecting pipeline(s) caused by customer's action.~~

5. ~~METERING REQUIREMENTS –~~
   a. ~~Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.~~

   b. ~~Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.~~

      ~~Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.~~

6. ~~The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

~~Reserved for Future Use~~

~~Reserved for Future Use~~

~~Reserved for Future Use~~

~~**INTERRUPTIBLE TRANSPORTATION SERVICE Rate 80**~~

~~**Availability:**~~

~~Service under this rate schedule is available on an interruptible basis to any commercial or industrial customer located in Wahpeton, North Dakota whose normal annual requirements are in excess of 1,000 Dk and who have satisfied Great Plains Natural Gas Co. of their ability and willingness to discontinue the use of said gas during the period of curtailment or interruption, by the use of standby facilities or suffering plant shut-down. 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. To obtain transportation service, a customer must meet the general terms and conditions of service provided hereunder and enter into a gas transportation agreement upon request of the Company.~~

~~**Rate:**~~

~~Basic Service Charge: $180.00 per month~~

~~Distribution Delivery Charge:~~
~~Maximum $0.669 per dk~~
~~Minimum $0.130 per dk~~

~~Customers shall pay Basic Service Charge plus a negotiated rate not to exceed the maximum rate or less than the minimum rate specified above.~~

~~**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.13, or any amendments or alterations thereto.~~

~~**General Terms and Conditions:**~~

1. ~~CRITERIA FOR SERVICE: In order to receive transportation service, customer must qualify under the Company's applicable natural gas transportation service rate and comply with the general terms and conditions of the service provided herein. The 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:~~
   a. ~~To qualify for gas transportation service a 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.~~

   b. ~~Requests for transportation service shall be considered in accordance with the provisions of Rate 100, §V.11.~~

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 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 under the Firm Gas Service – General Rate 65 (distribution delivery charge and cost of gas). 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. ~~The 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 the customer receives only gas transportation service in any billing period).~~

4. ~~PRIORITY OF SERVICE – 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.11.~~

5. ~~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 Gas Service – General Rate 65 (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.~~

6. ~~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 the customer's gas is not being delivered to the receipt point for any reason and the customer continues to take gas, the customer shall be subject to any applicable penalties or charges set forth in Paragraph 6.a. Gas volumes supplied by Company will be charged at the Firm Gas Service – General Rate 65 (distribution 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.~~

~~7. ELECTION OF SERVICE – Prior to the initiation of service hereunder, the customer shall make an election of its requirements under each applicable rate schedule for the entire term of service. If mutually agreed to by Company and customer, the term of service may be amended. Upon expiration of service, the customer may apply for and receive, at the sole discretion of the Company, gas service under the appropriate sales rate schedule for the customer's operations.~~

~~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.18.~~

~~8. DAILY IMBALANCE – To the extent practicable, customer and Company agree to the daily balancing of volumes of gas received and delivered on a thermal basis. Such balancing is subject to the customer's request and the Company's discretion to vary scheduled receipts and deliveries within existing Company operating limitations.~~

~~In the event that the deviation between scheduled daily volumes and actual daily volumes of gas used by customer causes the Company to incur any additional costs from interconnecting pipeline(s), customer shall be solely responsible for all such penalties, fines, fees or costs incurred. If more than one customer has caused the Company to incur these additional costs, all costs (excluding those associated with Company's firm deliveries) will be prorated to each customer based on the customer's over- or under-take as a percentage of the total.~~

~~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 a customer from correcting an imbalance which results in a penalty.

9. MONTHLY IMBALANCE – The customer's monthly imbalance is the difference between the amount of gas received by Company on customer's behalf and the customer's actual metered use. Monthly imbalances will not be carried forward to the next calendar month.

   a. Undertake Purchase Payment – If the monthly imbalance is due to more gas delivered on customer's behalf than the actual volumes used, Company shall pay customer an Undertake Purchase Payment in accordance with the following schedule:

% Monthly Imbalance	Undertake Purchase Rate
0 – 5%	100% Cash-out Mechanism
> 5 – 10%	85% Cash-out Mechanism
> 10 – 15%	70% Cash-out Mechanism
> 15 – 20%	60% Cash-out Mechanism
> 20%	50% Cash-out Mechanism

   Where the Cash-out Mechanism is equal to the lesser of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

b. Overtake Charge – If the monthly imbalance is due to more gas actually used by the customer than volumes delivered on their behalf, customer shall pay Company an Overtake Charge in accordance with the following schedule:

% Monthly Imbalance	Overtake Charge Rate
0 – 5%	100% Cash-in Mechanism
> 5 – 10%	115% Cash-in Mechanism
> 10 – 15%	130% Cash-in Mechanism
> 15 – 20%	140% Cash-in Mechanism
> 20%	150% Cash-in Mechanism

Where the Cash-in Mechanism is equal to the greater of the Company's WACOG or the Index Price, as defined in Paragraph 9(c).

c. The Index Price shall be the arithmetic average of the "Weekly Weighted Average Prices" published by Gas Daily for Emerson, Manitoba during the given month. The Company's WACOG (Weighted Average Cost of Gas) includes the commodity cost of gas and applicable transportation charges including the fuel cost of transportation.

10. METERING REQUIREMENTS:

a. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

b. Customer may be required, upon consultation with the Company, to contribute towards additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly

~~remedied or service under this tariff will be suspended until satisfactory corrections have been made.~~

~~Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.~~

~~11. DAILY NOMINATION REQUIREMENTS:~~

~~a. Customer or customer's shipper or agent shall advise Company's Gas Supply Department, via the Company's Electronic Bulletin Board in accordance with FERC time lines, of the dk requirements customer has requested to be delivered at each delivery point 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 a customer in excess of the quantities of gas to be delivered to customer.~~

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

~~12. WARRANTY – The 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 the 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.~~

~~13. FACILITY EXTENSIONS – If facilities are required in order to furnish gas transportation service, and those facilities are in addition to the facilities required to furnish firm gas service, the customer shall pay for those additional facilities and their installation in accordance with the Company's applicable natural gas extension policy. Company may remove such facilities when service hereunder is terminated.~~

~~14. 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.13, or any amendments or alterations thereto.~~

~~15. AGREEMENT – Upon request of the Company, customer may be required to enter into an agreement for service hereunder.~~

~~16. The foregoing schedule is subject to Rates 100 through 106 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.~~

~~Reserved for Future Use~~

~~COST OF GAS – NATURAL GAS RATE 88~~

~~1. Applicability:~~

~~This rate schedule constitutes a cost of gas (COG) provision and specifies the procedure to be utilized to adjust the rates for natural gas sold under Great Plains rate schedules in order to reflect: (a) changes in Great Plains' average cost of natural gas supply and (b) amortization of the Gas Cost Reconciliation account.~~

~~2. Effective Date and Limitation on Adjustments:~~

~~(a) The effective dates of the COG shall be service rendered on and after the first date of each month, unless the Commission shall otherwise order.~~

~~(b) Great Plains shall file to reflect changes in its average cost of gas supply only when the amount of change in such COG is at least $0.25 per dk. The adjustment to be effective October 1 shall be filed each year, regardless of the amount of the change.~~

~~3. Cost of Gas:~~

~~(a) The monthly COG shall reflect changes in Great Plains' cost of gas supply as compared to the cost of gas supply approved in its most recent COG filing.~~

~~(b) Firm Demand - The average cost of demand for Firm Gas Sales shall be computed on the basis of current pipeline rates and contract demand divided by twelve month weather normalized sales volumes applicable for the entire Great Plains' gas system.~~

~~(c) Gas Commodity - The average weighted commodity cost, including transportation and other costs associated with the acquisition of gas, from all suppliers for the month the COG will be in effect.~~

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

~~4. Gas Cost Reconciliation (GCR)~~

~~(a) For each twelve-month period ending August 31, a Gas Cost Reconciliation (GCR) will be calculated for each class set forth above. The GCR will be added to each customer class' cost of gas supply for the twelve-month period effective October 1 of each year. This adjustment shall include:~~

~~**GREAT PLAINS NATURAL GAS CO.**~~

~~*A Division of Montana-Dakota Utilities Co.*~~

~~**State of North Dakota**~~
~~**Gas Rate Schedule**~~

~~NDPSC Volume 2~~
~~1st Revised Sheet No. 7.1~~
~~Canceling Original Sheet No. 7.1~~

~~**COST OF GAS – NATURAL GAS RATE 88**~~

1. ~~The balance in the (over) under recovered gas cost account as of August 31.~~
2. ~~The difference between actual and recovered gas costs for each customer class for the twelve months ending August 31. The amount may be an under recovery or (over) recovery.~~
3. ~~Demand costs recovered from the interruptible sales customers will be credited to the firm general service customers.~~
4. ~~Any refunds from suppliers of gas or pipeline services.~~
5. ~~Carrying charges or credits at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.~~

~~(b) The resulting balance is divided by the projected dk sales for the next twelve months. The GCR adjustment shall be applied to the customers' monthly billings commencing on October 1 and remain in effective for a twelve (12) month period.~~

~~**Date Filed:**~~	~~September 22, 2021~~	~~**Effective Date:**~~	~~Service rendered on and after November 1, 2021~~
~~**Issued By:**~~	~~Travis R. Jacobson~~ ~~Director – Regulatory Affairs~~	~~**Case No.:**~~	~~PU-21-010~~

~~Reserved for Future Use~~

~~Title~~ ~~Page No.~~

~~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 North Dakota 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 – A customer requesting Company to provide service.~~

~~COMMISSION – Public Service Commission of the State of North Dakota.~~

~~COMPANY – Great Plains Natural Gas Co.~~

~~COMPANY'S OPERATING CONVENIENCE – The utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of Company's operations. This does not refer to the 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. Also includes any reduction of transportation natural gas service deemed necessary by the pipeline.~~

~~CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency supplied with service by 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 Company's meter(s) located on customer's premises.~~

~~EXCESS FLOW VALVE - Safety device designed to automatically stop or restrict the flow of gas if an underground pipe is broken or severed.~~

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

~~INTERRUPTIBLE CUSTOMER – Any individual, partnership, corporation, firm, other organization or government agency that will cease the use of natural gas or transportation service when deemed necessary by Company.~~

~~INTERRUPTION – A cessation of transportation or retail natural gas service deemed necessary by Company.~~

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

~~PIPELINE – The transmission company(s) delivering natural gas into Company's system.~~

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

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

~~SHIPPER – The party with whom the Pipeline has entered into a service agreement for transportation services.~~

~~**III. CUSTOMER OBLIGATIONS:**~~

1. ~~APPLICATION FOR SERVICE – A 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 the customer desiring the service. The Company may refuse a customer or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account. Any customer who uses gas service in the absence of 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. The customer will be responsible for payment of all service furnished through the date of discontinuance.~~

2. ~~INPUT RAT~~
   ~~hourly input rates 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 Company's sole discretion, 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 8 a.m. to 5 p.m. Monday – Friday unless an emergency situation requires access outside of these hours for the purpose of reading meters, making repairs, making inspections, removing the Company's property or for any other purpose incidental to the service.~~

4. ~~COMPANY PROPERTY – The customers 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 – The customer shall not disconnect, change connections, make connections or otherwise interfere with 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(s) over gas facilities, the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.~~

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

8. ~~TERMINATION OF SERVICE – All customers are required to notify the Company, to prevent their 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 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, death, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same.~~

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, devices owned, installed or maintained by the customer or leased by the customer from third parties. The customer is responsible for the proper installation and maintenance of all structures, equipment, lines, appliances, or devices on customer's side of the point of delivery. The customer must assume the duties of inspecting all structures including the house piping, chimneys, flues, and appliances on the customer's side of the point of delivery.~~

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 the customer's premises, except loss, injuries, death or damages resulting from the negligence of the Company.~~

4. ~~INDEMNIFICATION – Customer agrees to indemnify and hold 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. Company agrees to indemnify and hold customer harmless from any and all injury, death, loss or damage resulting from 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 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 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 authorization 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. 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 the 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 twelve months unless there is a material change in the 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 havin~~

~~3. SERVICE F~~
~~furnish, o~~
~~meter on the customer's premises.~~
~~Customer shall pay an installment or connection charge based upon the following rates:~~

~~(a) New Service Line Construction:~~

~~(~~
~~1) Minimum c~~
~~for customers with gas~~

~~input loads above 400,000 Btu/hour and $100.00 for interruptible customers.~~

~~(2) Service line installation charges shall be based upon the lesser of the Company's labor and material rates or the current cost per foot.~~

~~Length of service line shall be determined by measurement made from customer's property line to stop value on the service riser.~~

~~(b) Additional meters to existing service lines and inactive line connections:~~

~~A $25.00 connection charge covering the cost of service connection, general inspection, and gas turn-on will be collected at time of application from each individual requesting an additional meter to an existing service line or connection to an inactive line.~~

~~(c) Relocation of Existing Meters and Service Lines:~~

~~When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.~~

~~4. TEMPORARY SERVICE – At the discretion of the Company, temporary service may be rendered to a customer's premise. The Company may require the customer to bear the cost of installing and removing the service~~

~~in excess of any salvage realized. Advance installation payment may be required prior to installing the service.~~

~~The customer shall pay the regular rates applicable to the class of service rendered.~~

~~5. DISPATCHING – Transportation customers will adhere to gas dispatching policies and procedures established by Company to facilitate transportation service. Company will inform customer of any changes in dispatching policies that may affect transportation services as they occur.~~

~~6. RULES COVERING GAS SERVICE TO MANUFACTURED HOMES – The rules and regulation for providing gas service to manufactured homes are in accordance with the Code of Federal Regulations (24CFR Part 3280 – Manufactured Homes Construction and Safety Standards) Subpart 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.~~

~~7. 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.~~

~~(a) The amount of such deposit shall not exceed one and one-half times the estimated amount of one month's average bill.~~

~~(b) The Compa~~

~~guaranteed. The term of such contract shall be indeterminate, but it shall automatically terminate when the customer gives notice of service discontinuance to the Company or a change in location covered by the guarantee agreement of thirty days after written request for termination is made to the utility by the guarantor. However, no agreement shall be terminated without the customer having made satisfactory settlement for any balance, which the customer owes the Company. Upon termination of a guarantee contract, a new contract or a cash deposit may be required by the Company.~~

~~A deposit shall earn interest at the rate paid by the Bank of North Dakota on a six-month certificate of deposit as of the first business~~

~~day of each year. Interest shall be credited to the 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 twelve months, provided prompt payment record has been established.~~

~~8. METERING AND MEASUREMENT-~~

~~(a) Company will meter the volume 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. Company will test meters in accordance with applicable state utility rules and regulations.~~

~~(b) Interruptible sales and transportation service customers agree to provide the cost of the installation of remote data acquisition equipment; as required, to the Company before service is implemented as provided in the applicable rate schedule.~~

~~9. MEASUREMENT UNIT FOR BILLING PURPOSES – The measurement unit for billing purposes shall be (1) dekatherm (dk), unless otherwise specified. One dk equals 10 therms or 1,000,000 Btu's. Dk 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 used to reflect the heating value of the gas delivered.~~

~~10. 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 at a temperature base of sixty degrees Fahrenheit (60ºF). All measurement of natural gas by orifice meter shall be 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 AGA-3/NX-19, as amended, supercompressibility calculation.~~

~~Local sales base pressure is defined as five ounces per square inch gauge pressure plus local average atmospheric pressure.~~

~~11. PRIORITY OF SERVICE – Priority of Service from Highest to Lowest:~~
~~(a) Priority 1 – Firm sales services.~~
~~(b) Priority 2 – Interruptible sales and interruptible transportation services.~~
~~(c) Gas scheduled to clear imbalances.~~

~~Company 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 Company system.~~

~~Company reserves the right to provide service to customers with 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, Company will reinstate sales and/or transportation of gas according to each customer's original priority.~~

~~12. EXCESS FLOW VALVES – In accordance with Federal Pipeline Safety Regulations 49 CFR 192.383, the Company will install an excess flow valve on an existing service line at the customer's request at a mutually agreeable date. The actual cost of the installation will be assessed to the customer.~~

~~13. LATE PAYMENT – Amounts billed will be considered past due if not paid by the due date shown on the bill, or 22 days from date of bill. An amount equal to 1 1/3% per month will be applied to any unpaid balance if not paid by the due date, provided however, that such amount shall not apply where a bill is in dispute or a formal complaint is being processed. All payments received will apply to the customer's account prior to calculating the late payment charge. Those payments applied shall satisfy the oldest portion of the bill first.~~

~~14. RETURNED CHECK CHARGE – A charge of $15.00 will be collected by the Company for each check charged back to the Company by a bank.~~

~~15. 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 sales, use 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 the customer's service bills under this clause shall be limited to the customers within the corporate limits of the municipality, political subdivision or other entity imposing the tax.~~

~~16. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS For service requested by customers after the Company's normal business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday local time, a charge will be made for labor at standard overtime service rates.~~

~~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.~~

~~To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day~~

~~and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.~~

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

~~18. RECONNECTION FEE FOR SEASONAL OR TEMPORARY CUSTOMER A customer who requests reconnection of service, during normal working hours, at a location where same customer discontinued the same service during the preceding 12-month period will be charged a reconnection fee of $30.00.~~

~~Transportation customers who cease service and then resume service within the succeeding 12 months shall be subject to a minimum reconnection charge of $160.00 whenever reinstallation of the required remote data acquisition equipment is necessary.~~

~~19. DISCONNECTION OF SERVICE FOR NONPAYMENT OF BILLS – All amounts billed for service are due when rendered and will be considered delinquent if not paid by 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 of $30.00 before restoring gas service, which has been disconnected for nonpayment of service bills during normal business hours. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply if service is required that day and the work cannot be completed during normal working hours. Service may be scheduled for a future workday to avoid overtime charges.~~

~~20. DISCONNECTION 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 the 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 Company facilities.

The Company may collect a reconnect fee of $30.00 before restoring gas service, which has been disconnected for the above causes.

21. UNAUTHORIZED USE OF SERVICE – Unauthorized use of service is defined as any deliberate interference such as tampering with a Company 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.

(a) Examples of unauthorized use of service include the following, but are not limited to:

~~(1) Bypass piping around meter.~~
~~(2) Bypass piping installed in place of meter.~~
~~(3) Meter reversed.~~
~~(4) Meter index disengaged or removed.~~
~~(5) Service or equipment tampered with or piping connected ahead of meter.~~
~~(6) Tampering with meter or pressure regulator that affects the accurate registration of gas usage.~~
~~(7) Gas being used after service has been discontinued by the Company.~~
~~(8) 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.~~

~~(b) In the event that there has been unauthorized use of service, customer shall be charged for:~~

~~(1) Time, material and transportation costs used in investigation.~~
~~(2) Estimated charge for non-metered gas.~~
~~(3) On-premise time to correct situation.~~
~~(4) Any damage to Company property.~~
~~(5) All such charges shall be at current standard or customary amounts being charged for similar services, equipment, facilities and labor by the Company. A minimum fee of $30.00 will apply.~~

~~(c) Customer service so disconnected shall be reconnected after a customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid all charges as hereinafter set forth in this procedure.~~

~~(1) All delinquent bills, if any.~~
~~(2) The amount of any Company revenue loss attributable to said tampering.~~
~~(3) 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 number 21.b above.~~
~~(4) Reconnection fee equal to the Company's minimum service charge.~~

~~(5) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with Commission Rules.~~

~~22. BILLING ADJUSTMENTS –~~

~~(a) In the event a customer's gas service bill is found in error resulting from a meter equipment failure, the Company may adjust back and rebill the bills in error for a period not to exceed six months.~~

~~(b) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where the service was provided under Rate 65, the Company may adjust back and rebill the bills in error for a period not to exceed six months.~~

~~(c) In the event a customer's gas service bill is found in error due to a reason other than that stated in (a) above resulting in an undercharge and where service was provided under an interruptible service schedule, the Company may adjustment back and rebill the bills in error for a period not to exceed six years.~~

~~(d) In the event a customer's gas service bill is found in error resulting in an overcharge, the Company may adjust back to the known date of error and refund the customer the amount of the overbilled.~~

~~**Applicability:**~~

~~This rate schedule specifies the protocol to be followed for the testing of gas meters in compliance with Sections 69-09-01-14 and 69-09-01-16 of the North Dakota Century Code.~~

~~**Testing Process for New Meters**~~

1. ~~Meter supplier(s) shall provide test data for all meters.~~

2. ~~A sampling of 5% of new meter lots received will be tested at full load and light load. If unsatisfactory, all meters in the shipment shall be tested, and repaired if necessary, or shipment shall be returned to the manufacturer.~~

~~**Testing Process for Meters in Service:**~~

1. ~~This meter test schedule shall not apply to meters larger than 650 cubic feet per hour (cfh). Such meters shall be tested and adjusted or repaired, if necessary, at a periodic interval of at least once in ten years.~~

2. ~~All active meters, 650 cfh and smaller will be combined into a single random test program. Great Plains meters shall be combined with Montana-Dakota Utilities Co. meters for purposes of random sample testing only.~~

3. ~~At the time the random selection is made, meters more than ten years old and active meters that have not been tested in the last ten years will be placed into an installation class defined model installation date lot to be part of a random population for testing.~~

4. ~~All active meters rated at 650 CFH and smaller, will be assigned to lots on the basis of installation date. Meters shall be divided into lots based on manufacturer, type, and last install date in five year groups. The minimum number of samples taken from each lot will be as specified by Military Standard 414, Sample Procedures and Tables for Inspection by Variables for Percent Defective, inspection level IV with specification limits of +2.0%.~~

5. ~~The meters tested within the random test program will include meters selected via a computer generated random selection process and meters pulled from a customer's premise in correlation with service technicians being on-site for other service related work.~~

6. ~~Lot acceptability will be determined by the standard deviation method based on single sample, double specification limit, variability unknown, for an acceptable~~

~~quality level of 15%. The following actions will be taken based on the test results:~~

~~a. A meter for which the sample is satisfactory will remain in service.~~

~~b. A meter lot for which the sample fails may remain in service if it passed the previous year and if no more than 10% of the sample registers over 102%.~~

~~c. A meter lot for which the sample fails will be evaluated if the lot failed the previous year or if more than 10% if the sample registers over 102%~~

~~i. If evaluation determines the group is homogeneous, then the entire group will be removed.~~

~~ii. If group is not homogeneous and a subset of the group is found defective, the subset will be removed. Removal of a failed lot of meters or failed subset of lot will be removed from service for testing and repair within one year.~~

~~**Reporting:**~~

~~Great Plains shall file reports of its meter test results by December 15 for the meter testing conducted for the previous calendar year.~~

~~**FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105**~~

~~The Company will install gas main extensions using the following guidelines applicable to firm gas main extensions:~~

a) ~~The term "main" refers to the facilities that are typically constructed from a border station or regulator station with no particular terminus at a building or structure. Mains are normally installed in streets, alleys, dedicated public ways or dedicated utility easements.~~

b) ~~Customer refers to customer ultimately taking natural gas service or a developer request to provide natural gas service to residential customers.~~

c) ~~Cost Participation. Cost participation for firm gas extensions shall be determined as follows:~~

   i) ~~Extensions 95 Feet or Less – The Company will extend a gas main up to, but not to exceed, 95 feet per home projected to be connected within twelve (12) months from the start of construction where natural gas is the primary fuel used for space heating.~~

   ii) ~~Extensions over 95 Feet or where natural gas in not the primary fuel used for space heating – The Company may require cost participation if the estimated capital expenditure is not cost justified. The extension will be considered cost justified if the calculated Maximum Allowable Investment equals or exceeds the estimated capital expenditures using the following formula:~~

~~Maximum Allowable Investment (MAI) =~~

~~Annual Basic Service Charge +~~

~~(3rd Year Estimated Dk x Distribution Delivery Charge)/LARR~~

~~Where: LARR = 12.328%~~

~~The LARR, defined as the Levelized Annual Revenue Requirement Factor, is the annual rate required to recover the present value of a project over the life of a project.~~

~~**FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105**~~

~~d) Cost of the extension shall include the gas main extension(s), valves, service line(s), cathodic protection equipment, 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.~~

~~e) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.~~

~~f) Contributions. In the event the extension is not cost justified, the customer(s) shall pay the Company the portion of the capital expenditures not cost justified. The extension will proceed if the customer:~~

~~i) Pays in advance to the Company the excess amount not cost justified in cash, or~~

~~ii) Agrees to pay a special monthly charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or~~

~~iii) Agrees to pay annually a specified minimum charge. If the customer discontinues service prior to the excess being paid in full, the balance will be due and payable upon discontinuance of service, or~~

~~iv) Agrees to a combination of above methods, or~~

~~v) Customer may post a bond or an irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.~~

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

~~vii) If within the five year period from the extension(s) in service date, the number of active customers and related volumes exceeds the projections used to determine MAI, the Company shall re-compute the contribution requirement by recalculating the MAI.~~

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

~~g) Refunds. Contributions for gas main extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension as additional customers are connected to the particular main extension for which the advance was made.~~

~~i) The Company will refund to the original contributor(s) the amount required to reduce their contribution to the recalculated contribution requirement. Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements.~~

~~ii) No refunds will be made until the new applicants begin taking service from the Company.~~

~~iii) 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.~~

~~iv) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.~~

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

~~**FIRM GAS SERVICE MAIN AND SERVICE LINE EXTENSION POLICY Rate 105**~~

~~i) Firm Gas Service Line Extensions:~~
~~The Company shall install gas service lines using the following general rules and regulations applicable to all firm gas service line extensions:~~

~~i) The term "service line" refers to facilities that are constructed from a main to the final terminus at a building or structure.~~

~~ii) The Company shall furnish, own, and maintain all material and equipment to the outlet side of the meter on the customer's premise(s).~~

~~iii) The Company will extend a service line to serve customer(s) where natural gas is the primary fuel used for space heating without charge up to, but not to exceed, 65 feet. The length of the service line shall be determined by measurement from the customer's property line to the stop valve on the service riser.~~

~~iv) If the additional service line required is beyond 65 feet or natural gas is not the primary fuel used for space heating, the Company may require cost participation if the estimated capital expenditure is not cost justified. The service line extension will be considered cost justified if the calculated MAI equals or exceeds the estimated capital expenditures using the MAI formula provided in ¶ c.ii.~~

~~v) Where cost participation is required, such extension is subject to execution of the Company's standard agreement for extensions by the customer.~~

~~vi) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and materials rates.~~

~~A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $25.00 per meter for customers with gas input loads up to 400,000 BTU/hour; and $50.00 per meter for customers with gas input loads above 400,000 BTU/hour.~~

INTERRUPTIBLE GAS MAIN AND SERVICE LINE EXTENSIONS POLICY Rate 106

The Company will install gas main and service line extensions using the following guidelines:

a) Contribution. 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), cathodic protection equipment, regulators, meters (excluding remote data acquisition 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.

   i) The extension will proceed if the customer:

      (1) Pays in advance to the Company the total cost of construction, or

      (2) Customer may post a bond or irrevocable letter of credit in the amount of the required contribution prior to construction and acceptable by the Company. Such bond, issued by a bonding company authorized to do business in the state or letter of credit 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.

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

   iii) Remote data acquisition equipment costs shall be subject to the terms and conditions specified in the Company's Interruptible Gas Transportation Rates.

b) Refund. Contributions for gas main and service line extensions are refundable, without interest, for a period up to five (5) years from the date of completion of the main extension.

   i) If within the five-year period from the extension(s) in service date, the total of

~~**INTERRUPTIBLE GAS MAIN AND SERVICE LINE EXTENSIONS POLICY Rate 106**~~

~~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, the Company shall refund the amount exceeding the revenue requirement on the following basis:~~

~~(1) Annually, beginning at the second (2nd) 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.~~

~~(2) Customers who have posted a bond or letter of credit will be notified of any reduction in surety or guarantee requirements based on the above calculation.~~

~~(3) No refund shall be made by Company after the five-year refund period and in no event shall the refund exceed the amount of the contribution.~~

~~ii) If within the five-year period from the extension(s) in service date, additional customers (firm or interruptible) are connected to an interruptible customer's main extension, the Company shall (1) determine the pro rata cost share applicable to the other customer (2) reduce the original customer's contribution requirement by the pro rata cost attributed to the new customer and (3) calculate an MAI for a firm customer through the process described in Rate 105 ¶ c.ii or collect the full amount for an interruptible customer. The amount collected will be subject to the applicable refund provisions for the remainder of the refund period.~~

~~c) Relocation of Existing Meters and Service Lines: When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.~~

~~d) A minimum connection charge, per meter, covering the cost of the installation of the meter and regulator, the service connection, general inspection, and gas turn-on is payable at the time the application for service is submitted. The minimum connection charge is $100.00 for interruptible customers.~~

MONTANA-DAKOTA UTILITIES CO. AND GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-___

Direct Testimony

Of

Nicole A. Kivisto

Q. Please state your name and business address.

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

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

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

Q. Please describe your duties and responsibilities with MDU Utilities Group.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above-mentioned companies that, in combination, serve over 1.182 million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting from Minnesota State University Moorhead. I began working for MDU Resources/Montana-Dakota in 1995 and have been in my current capacity since January 2015. I was the Vice President-Operations of Montana-Dakota and Great Plains from January of 2014 until assuming my present position.

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

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 Montana and Wyoming, the Public Utilities Commissions of Idaho, Minnesota, and South Dakota, the Public Utility Commission of Oregon and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's gas operations in the state of North Dakota and an overview of the Company's request for a gas rate increase and discuss the policies and reasons underlying the major aspects of the request. I will also introduce the other Company witnesses who will present testimony and exhibits in further support of the Company's request. Finally, I will address the need for an interim increase and introduce the other Company witnesses who will present testimony and exhibits in further support of the Company's request.

Q. Would you please address the relationship between Montana-Dakota and Great Plains and how that affects this rate case?

A. Yes. Great Plains is a Division of Montana-Dakota and operates as a district. Great Plains serves customers in Minnesota and the community of Wahpeton and the surrounding area in North Dakota. There are approximately 2,346 customers in North Dakota and its operations are currently managed in a manner similar to Montana-Dakota's other districts, such as Jamestown. In Case Nos. PU-17-490 and PU-17-075, approved by this Commission, the Parties agreed to begin combining all gas operations within North Dakota for reporting purposes as a first step to having one North Dakota gas utility operation. In Case No. PU-20-379, also approved by this Commission, the parties agreed to maintain separate tariffs but made structure changes to the existing Great Plains' rate schedules. I will address steps proposed in this rate case to further align the service provided to Wahpeton under Montana-Dakota's tariff. Mr. Larry D. Oswald will provide further testimony regarding the communication plan for the Wahpeton customers.

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

A. The Company currently provides natural gas service to approximately 117,700 customers in 77 communities in North Dakota, operating approximately 2,888 miles of distribution mains and approximately 118,813 service lines. The customer base is 84 percent residential and 16 percent commercial and industrial. As of December 31, 2022, the Company had 510 full and part-time employees who live and work throughout the Company's North Dakota electric and natural gas service area. Montana-Dakota's North Dakota natural gas service area is divided into two operating regions with regional offices located in Bismarck and Dickinson, North Dakota. In addition to the regional offices, there are fully staffed operations centers located in the communities of Minot, Williston, and Devils Lake, with satellite offices in Watford City and Jamestown. Great Plains' North Dakota natural gas service area is serviced out of Great Plains' office in Fergus Falls, Minnesota.

Montana-Dakota's customers have toll-free access to the Customer Experience Team and the Credit Center to place routine utility service requests and inquiries from 7:30 am to 6:30 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A scheduling center, part of the Customer Experience Team, transmits electronic service orders to the mobile terminals placed in our fleet of service and construction vehicles. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Would you please provide more information regarding the customers the Company serves?

A. Yes. 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. Summer loads are small by comparison. The Company is projecting to deliver approximately 27.0 Mmdk of natural gas to customers in North Dakota in 2024. The natural gas requirements by customer class is as follows: approximately 33 percent residential, 36 percent firm general service, 9 percent small interruptible, 20 percent large interruptible, and 2 percent for the Air Force.

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 delivered 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 the Company purchases from suppliers is a commodity like wheat or corn, the price of which is not regulated. The cost of delivering the gas to the Company's distribution system at the town border station is regulated by the Federal Energy Regulatory Commission (FERC) or other regulatory agencies. These gas costs are passed on to customers on a dollar-for-dollar basis as specified in the Commission approved Purchased Gas Cost Adjustment tariff. The gas portion of the cost of providing natural gas service currently comprises about 58 percent of a typical residential bill for gas service.

The distribution cost portion of the Company's cost of service is the subject of this proceeding. This element includes the costs of new and existing distribution investments, replacement of aging infrastructure, operation and maintenance expenses, and the opportunity to earn a return on the Company's investments in facilities that provide natural gas service. Distribution costs are currently 42 percent of a typical residential bill.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

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

A. The Company is requesting an increase in its gas rates because our current rates do not reflect the cost of providing natural gas service to North Dakota customers. For the twelve months ending December 31, 2022, the Company's Rate of Return was 5.35 percent. This is below the last authorized Rate of Return of 6.851 percent in Case No. PU-20-379.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting $11,640,010 which represents a 7.45 percent increase based on a projected 2024 test year. This increase represents an average yearly increase of 2.5 percent per year.

Q. How would this increase effect the Company's residential customers?

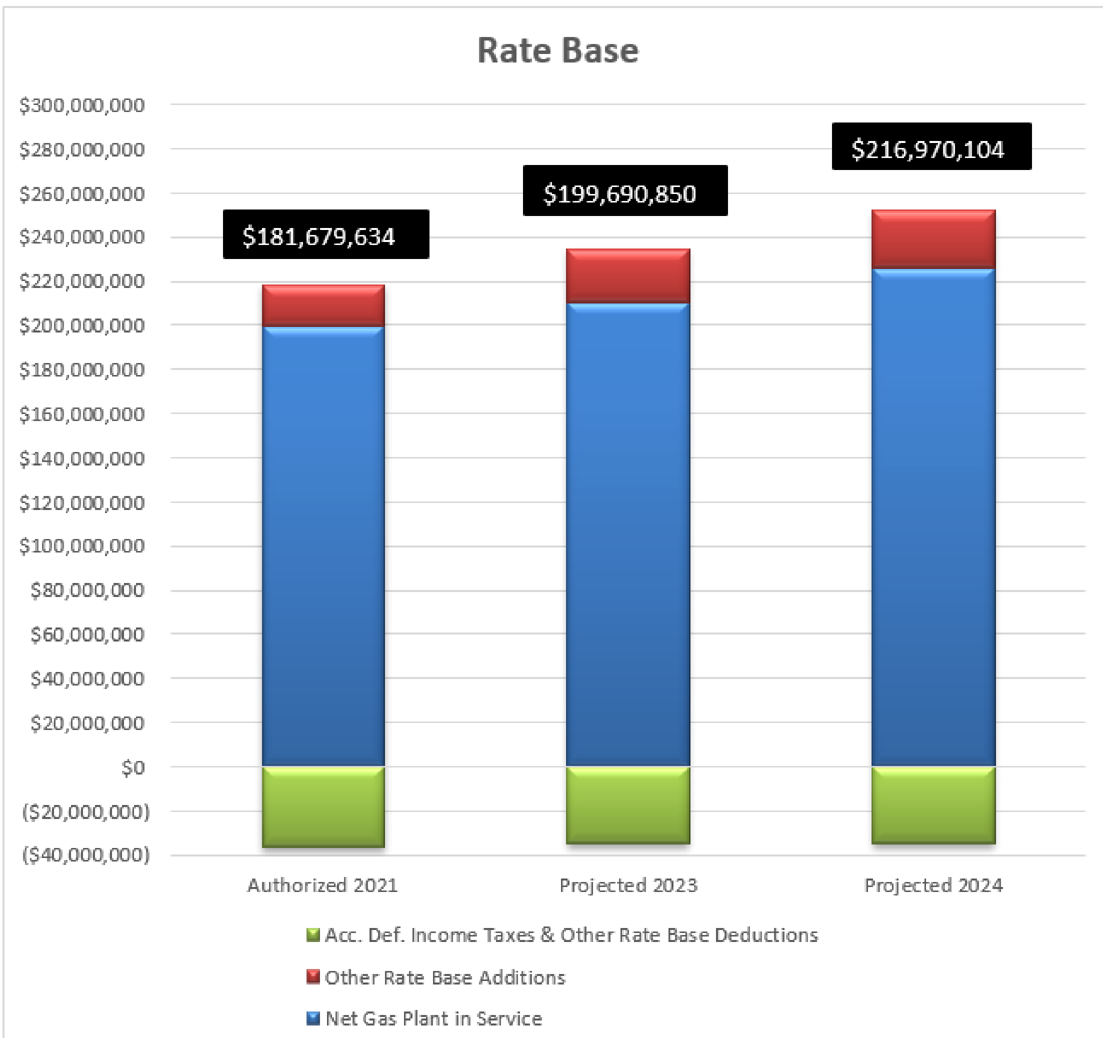
A. Montana-Dakota's small residential customers would see an increase of 9.76 percent from current rates. As a result, an individual residential customer using 6.8 Dk per month will see an increase of approximately $5.89 per month.

Wahpeton residential customers would see an increase of 10.62 percent from its current rates. Therefore, an individual residential customer using 6.7 Dk per month will see an increase of approximately $5.16 per month.

Q. What are the primary reasons that Montana-Dakota and Great Plains need an increase at this time?

A. The Company's cost of doing business in North Dakota is increasing despite the Company's efforts to control costs and increase efficiency. The Company has invested approximately $36.8 million between 2019 and 2022 to improve the safety and reliability of its distribution system in North Dakota. Increases in O&M expenses and the investments made since the last rate case has driven the need for increased gas rates.

As depicted in the graph below, the Company's net adjusted rate base is projected to grow approximately $35 million or 19.4 percent since the approved 2021 rate base.



Due to price increases and inflationary pressures, the Company's total O&M costs have increased over those approved in the Company's last gas rate case. As shown in the table below, after adjusting the 2021 Authorized O&M to exclude the costs associated with cost of gas, the Company's 2024 Projected O&M expenses are projected to increase approximately 25 percent. This represents a 7.7 percent compounded increase per year since the last filing.

	Approved 2021	Projected 2024	Variance	Percent Variance
Cost of Gas	$73,319,285	$106,767,865	$33,448,580	45.62%
Labor	13,161,526	15,288,799	2,127,273	16.16%
Subcontract Labor	997,289	1,552,808	555,519	55.70%
Vehicles and Work Equipment	784,421	1,490,860	706,439	90.06%
Software Maintenance	907,828	1,370,613	462,785	50.98%
Rent	524,756	1,065,775	541,019	103.10%
Other O&M	6,962,434	8,350,242	1,387,808	19.93%
Total O&M Expense	$96,657,539	$135,886,962	$39,229,423	40.59%
Total Excluding Cost of Gas	$23,338,254	$29,119,097	$5,780,843	24.77%

Q. How have the Company's labor expenses changed since the last case?

A. The Company's projected labor expenses for the year ending December 2024 have increased approximately 16 percent since the approved 2021 rate case which represents a 5.12 percent compounded year over year increase.

Additionally, Montana-Dakota, like many other organizations in the country, has struggled to recruit, train, and retain personnel in the current competitive job market. Furthermore, the Company has faced increased labor market costs, particularly for those in entry level positions.

In late 2021 the Company finalized its labor contract with the

System Council U-13 of the IBEW. This contract, which runs through April 2024, defined an approximately 3.00 percent labor expense increase per year. The Company anticipates this contracted annual adjustment to increase starting May 1, 2024 and has adjusted the 2024 labor projection accordingly. Its effect is discussed in the testimony of Ms. Tara R. Vesey.

Q. Have there been other increases in expenses since the last case?

A. The Company has seen other increases to O&M expenses since the last case, such as subcontract labor, vehicles and work equipment, software maintenance, and rent, which will be more fully covered in the testimony of Ms. Vesey.

The operation and maintenance expenses associated with subcontract labor have increased approximately $556,000 primarily for third party line locating and leak surveying. Vehicles and Work equipment increased approximately $706,000 primarily due to increased depreciation rates for Power Operated Equipment within the studies supported by Mr. Kennedy. The depreciation expense related to vehicles and work equipment is charged to a clearing account and is thus recorded as an O&M expense. Software maintenance expense increased approximately $463,000 from the approved 2021 rate case due to increases in subscription renewals and mandated security needs. Rent expense increased approximately $541,000 from the approved 2021 rate case due to additional building leases and higher forecasted expenses related to North Dakota's allocation of shared software.

Q. Have you performed depreciation studies for inclusion in this request?

A. Yes. Depreciation studies for Montana-Dakota's gas and common plant in service were performed by Mr. Larry Kennedy of Concentric Advisors, ULC. Mr. Kennedy has provided testimony on behalf of the Company and is recommending a composite gas plant depreciation rate of 3.77 percent and a 5.31 percent common depreciation rate, both of which are based on plant in service as of December 31, 2021. The impact of the depreciation study results in a North Dakota gas jurisdiction decrease of approximately $789,000 in depreciation expense, as compared to the previously approved rates.

Q. You have discussed a number of items, can you briefly explain the additional revenue requirement?

A. In summary, as shown in the table below, the $11.6 million increase in revenue is driven primarily by:

	Amount (in millions)
O&M Increase	$5.8
Total Capital Investment Including SSIP	3.9
Depreciation Expense	1.6
Change in Cap Structure	1.6
Incremental Margin Offset	(1.2)
Other	(0.1)
	$11.6

The Company's cost of doing business in North Dakota is increasing despite the Company's effort to control costs and increase efficiency. As noted above, the Company is experiencing a $5.8 million increase in O&M expenses. In addition, the Company has made capital investments, inclusive of the System Safety Integrity Program (SSIP), which have resulted in a $3.9 million increase. Higher depreciation expenses have been the result of investments made since the last case; however, these increases were partially offset by lower proposed depreciation rates. Also, the proposed capital structure results in an increase in the revenue requirement. Finally, these increases were partially offset by incremental margin associated with new customer opportunities and growth.

Q. What incremental investments are included in this case as Projected 2024?

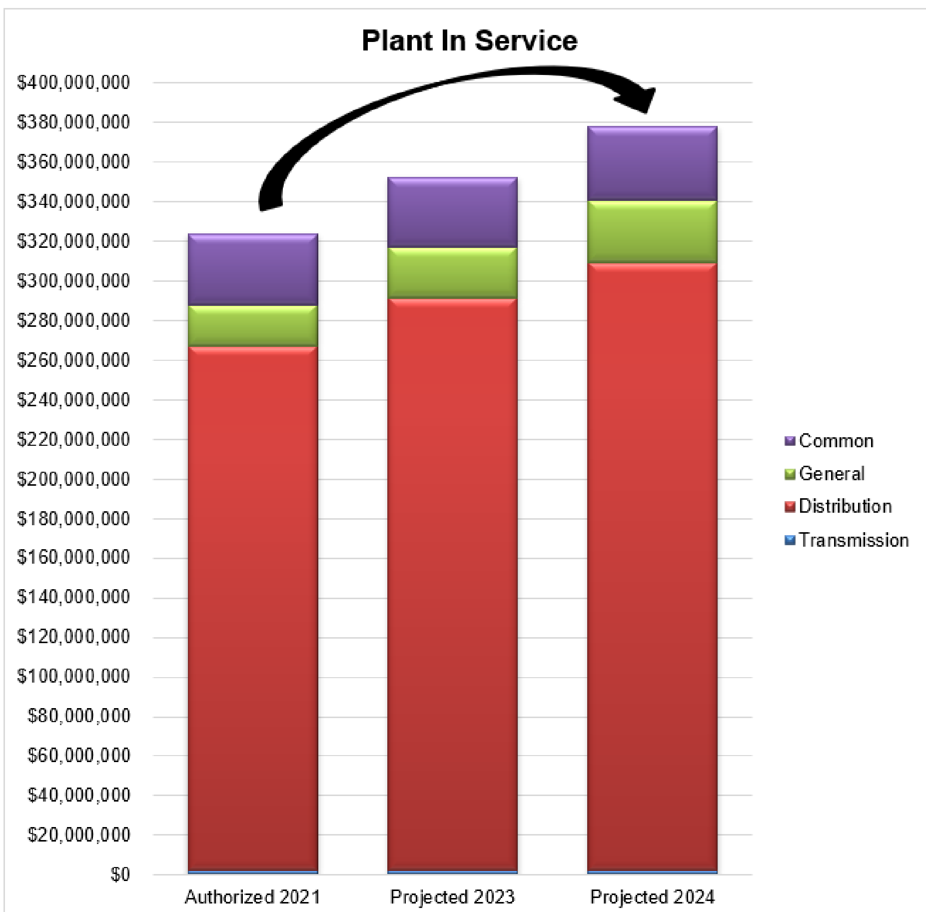
A. The Company has included incremental investments for 2024 of approximately $36.9 million and are associated with the following investments:

- Distribution investment of approximately $21.9 million including mains and service lines growth and replacements, town border stations, Wahpeton mains and regulator stations, SSIP upgrades required to maintain safe and reliable service, and gas meters as discussed in greater detail by Mr. Eric P. Martuscelli, Mr. Larry D. Oswald, Mr. Jesse Volk, and Mr. Jeremy J. Ogden;
- General plant additions of approximately $10.2 million associated with work equipment, structures, and improvements, primarily

includes general tools, Picarro Leak Survey Equipment, two-way radio system, and town border station upgrades as discussed in greater detail by Mr. Martuscelli Mr. Micheal Schoepp, Mr. Darcy J. Neigum, Mr. Renie Sorensen, and Mr. Shawn Nieuwsma;

- Common plant additions of approximately $4.8 million associated with work equipment, structures, and improvements, primarily includes Work Asset and Management software, as discussed in greater detail by Mr. Hart Gilchrist.

The table below shows the investment in plant assigned and allocated to North Dakota gas operations from 2021 to projected 2024.



Q. Would you please describe the investment in distribution facilities in greater detail?

A. The investment in system safety and integrity is a focused effort based on the Company's Distribution Integrity Management Program (DIMP). Mr. Volk will explain in further detail how the DIMP is used to identify the pipeline replacement projects necessary for safety reasons and to reduce risk on the Company's system.

Furthermore, as is fully explained in the testimony of Mr. Shawn Nieuwsma, due to large and growing communities that Montana-Dakota serves, the Company needs to make changes to its design day requirements. The increases or changes to the customer count and/or usage patterns is requiring the Company to upgrade Town Border Stations (TBS). These upgrades require investment in order to safely and reliably meet the customers needs.

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

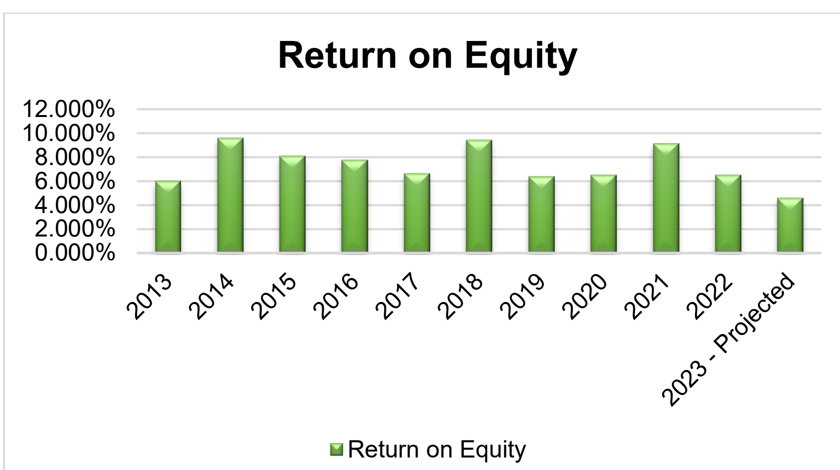
A. The allocation of revenue is based on the Class Cost of Service Study, which is supported by Mr. Ronald J. Amen. The proposed percentage change in rates by customer class are as follows:

Rate Class	Overall Class Impact
Residential Service	9.84%
Firm General Service	4.82%
Air Force	20.45%
Small Interruptible Service	4.31%
Large Interruptible Service	7.02%
Total	7.45%

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

A. The Company is requesting an overall return of 7.563 percent, inclusive of a return on equity (ROE) of 10.5 percent. Ms. Ann E. Bulkley's analysis indicates that a 10.5 percent ROE is fully justified and supported based on the results of her studies.

The table below shows the reported return on equity from 2013 to projected 2023.



Q. The Company is proposing a phased approach to combine Great Plains' gas operations in North Dakota with Montana-Dakota's gas operations. Will you please explain?

A. Yes. In this filing, the Company proposes to begin the phase in of Wahpeton's customers to become Montana-Dakota customers. Upon implementation of final rates in this case, Great Plains customers will be served under a unique Montana-Dakota tariff but will continue to receive a Great Plains bill for six months following implementation of final rates in this case. At that time customers will begin receiving their natural gas bills under a Montana-Dakota invoice. There will be no change in the rates charged to customers at the time Wahpeton customers move to a Montana-Dakota invoice. This is more fully described in the testimony of Ms. Stephanie Bosch.

The completion of common rates between Great Plains and Montana-Dakota customers will take place in a future rate case in order to avoid significant changes in the rate structure.

Q. Is the Company seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with North Dakota Century Code 49-05-06. The amount of interim relief sought is $10,094,595 or 6.46 percent and consists of the Company's projected 2024 revenue requirement adjusted to reflect the return on equity of 9.30 percent authorized in Case No. PU-20-379 and the exclusion of items that were not a part of the last rate case. The interim request will be described in more detail by Ms. Tara R. Vesey. The proposed interim rates are described by Ms. Stephanie Bosch. The interim increase is necessary to provide the Company an opportunity to recover the costs of providing service to customers today.

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

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

- Ms. Tammy J. Nygard, Controller for the MDU Utilities Group, will testify regarding the Company's overall cost of capital, capital structure, and overall debt costs.
- Ms. Ann E. Bulkley, Principal for The Brattle Group, will testify regarding the appropriate cost of common equity for Montana-Dakota's and Great Plains' North Dakota gas operations.
- Mr. Hart Gilchrist, Vice President of Safety, Process Improvement, and Operations Systems for the MDU Utilities Group, will testify regarding the Company's Work and Asset Management system deployment.

- Mr. Micheal Schoepp, Director of Operation Services for the MDU Utilities Group, will testify regarding the Company’s Picarro Leak Survey Equipment and Technology capital expenditures.
- Mr. Shawn Nieuwsma, Manager of Gas Supply for Montana-Dakota and Great Plains, will testify regarding the Company’s town border stations capital expenditures in Washburn, Devils Lake, and Grafton, North Dakota.
- Mr. Renie Sorensen, Manager of Engineering Services for the MDU Utilities Group, will testify regarding the Company’s Minot Reinforcement project and Jamestown Town Border Station capital expenditures.
- Mr. Jesse Volk, Manager of System Integrity for the MDU Utilities Group, will testify regarding the Company’s System Safety and Integrity capital expenditures.
- Mr. Jeremy J. Ogden, Director of Construction Services and Gas Measurement for the MDU Utilities Group, will testify regarding the Company’s gas meter capital expenditures and capital expenditure of the Construction Services shop located in Bismarck, North Dakota.
- Mr. Darcy J. Neigum, Director of System Operations and Planning for Montana-Dakota, will testify regarding the Company’s two-way radio replacement capital expenditure.
- Mr. Eric P. Martuscelli, Vice President of Field Operations for the MDU Utilities Group, will testify regarding the Company’s mains and service

lines growth and replacement capital expenditures and general tools and work equipment capital expenditures.

- Mr. Larry E. Kennedy, Senior Vice President for Concentric Advisors, ULC., will testify regarding the depreciation studies for Montana-Dakota's and Great Plains' gas and common operations of the plant in service as of December 31, 2022, that supports the proposed depreciation rates in this filing.
- Mr. Larry D. Oswald, Director Business Development and Energy Services for Montana-Dakota, will testify regarding the WBI Energy Wahpeton transmission line and the Company's associated town border station for Wahpeton and the expansion to the City of Kindred, City of Portal distribution system, service to a North Dakota Soybean Processor Plant, system betterment investments required under the Gas Service Extension Policy Rate 120, Natural Gas Energy Efficiency Program, and conversion of Great Plains Wahpeton tariffs to Montana-Dakota tariffs.
- Mr. Nathan A. Bensen, Senior Regulatory Analyst for Montana-Dakota, will testify regarding the Company's projected volumes in this case.
- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the Company's total revenue requirement.
- Mr. Ron J. Amen, Managing Partner for Atrium Economics, LLC, will testify regarding the Company's embedded class cost of service study and proposed rate design.

- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the Company's proposed tariff changes, including the proposed small and large customer class basic service charge and volumetric charge.

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

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

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23___

Direct Testimony

Of

Tammy J. Nygard

Q. Please state your name and business address.

A. My name is Tammy J. Nygard, 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 Controller for Montana-Dakota Utilities Co. (Montana-Dakota), Cascade Natural Gas Corporation (Cascade) and Intermountain Gas Company (Intermountain), subsidiaries of MDU Resources Group, Inc. (MDU Resources) as well as Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, collectively the MDU Utilities Group.

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

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade, and Intermountain.

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 Computer Information Systems. I have over 20 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

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

A. Yes, I have testified before this Commission, the Public Utilities Commission of Idaho, Minnesota and South Dakota, the Public Utility Commission of Oregon, the Public Service Commissions of Montana and Wyoming, the Washington Utilities and Transportation Commission, and the Federal Energy Regulatory Commission.

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

A. I am responsible for presenting Statement E.

Q. Was this statement and the data contained therein prepared by you or under your supervision?

A. Yes, it was.

Q. Is it true to the best of your knowledge and belief?

A. Yes, it is.

Q. Would you please explain Statement E?

A. Statement E summarizes the average utility capital structure and the related costs of debt and common equity of Montana-Dakota for the twelve months ended December 31, 2022 and the projected average capital structure for 2023 and 2024. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate case filing of 7.563 percent. The basis for the requested 10.5 percent return on common equity contained within the overall requested rate of return is supported by the testimony of Ms. Ann E. Bulkley.

The components of the 2024 projected overall annual rate of return, which are used by Ms. Vesey to calculate the revenue requirement, are:

	Ratio	Cost	Weighted Cost of Capital
Long-Term Debt	45.296%	4.569%	2.070%
Short-Term Debt	4.519%	4.954%	0.224%
Equity	50.185%	10.500%	5.269%
Rate of Return	100.000%		7.563%

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

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made and plans to make significant capital expenditures for new plant investment throughout its service territory, especially in mains and services, including System Safety and

Integrity Projects (SSIP) and town border stations. These new investments also have associated operating and maintenance costs. Through its financial planning process, the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations with a target of 50 percent common equity capital structure at year end. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of the Company's short-term credit line and the issuance of additional long-term debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

The Company did not obtain any additional common equity in 2022 and is not expecting to receive any additional common equity in 2023 or 2024.

The Company did not issue any new long-term debt in 2022 and is not expecting to issue any new long-term debt in 2023. In 2024, the Company has $60 million of senior notes maturing and anticipates issuing long-term debt of $125 million, partially to replace the $60 million senior notes maturing.

Q. What does Statement E, Schedule E-1 show?

A. Page 1 is a summary showing the Company's average long-term debt at December 31, 2022 and associated cost of debt, and it shows the projected long-term debt and associated costs for 2023 and 2024.

Page 2 shows the cost and the debt balance by issue at December 31, 2022. Page 3 shows the projected cost and the debt balance by issue at December 31, 2023 and page 4 shows the projected cost and the debt balance by issue at December 31, 2024, including the additional $125 million of long-term debt previously discussed.

Q. How did you derive the projected cost of debt for 2023 and 2024?

A. The projected cost of debt for 2023 and 2024 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement E, Schedule E-2?

A. Schedule E-2 presents the twelve-month average short-term debt balance for 2022 and projected 2023 and 2024 as well as the 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 year-end balance.

Q. What does Statement E, Schedule E-3 show?

A. The schedule presents the average common equity balance at December 31, 2022 and the projected average balances for December 31, 2023 and December 31, 2024 reflecting the projected activity in the balances.

Q. Would you please describe Statement E, Schedule E-4 and explain the amortization method utilized?

A. Schedule E-4 reflects the annual amortization of the costs associated with the redemption of long-term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues. The balance was fully amortized in 2022. The Company uses the same calculation for accounting purposes. There are no costs associated with these notes in 2023 or 2024.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
CASE NO. PU-23-___
PREPARED DIRECT TESTIMONY OF
ANN E. BULKLEY

Q1. Please state your name and business address.

A1. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated gas utility operations of Montana-Dakota Utilities Co. in North Dakota ("Montana-Dakota" or the "Company").

Q3. Please describe your education and experience.

A3. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a listing of the testimony that I have filed in other proceedings as Exhibit No.___(AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. Please describe the purpose of your testimony.

A4. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for the Company and to assess the reasonableness of its proposed capital structure used for ratemaking purposes.

Q5. Are you sponsoring any schedules in support of your Direct Testimony?

A5. Yes. My analysis and recommendations are supported by the data presented in Exhibit No. ___(AEB-2), Schedules 2 through 13, which were prepared by me or under my direction.

Q6. Please provide a brief overview of the analyses that led to your ROE recommendation.

A6. I have estimated the cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration: (1) the Company's small size relative to the proxy group; (2) flotation costs; (3) the Company's anticipated capital expenditure requirements; and (4) the Company's regulatory risk as compared with the proxy group. Finally, I considered the Company's capital structure as compared with the capital structures of the proxy companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q7. How is the remainder of your testimony organized?

A7. The remainder of my testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions the cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity estimates and the analytical basis for my recommendation of the appropriate ROE for Montana-Dakota.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII provides an assessment of the reasonableness of the Company's proposed capital structure relative to the proxy group.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSES AND CONCLUSIONS

Q8. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A8. In developing my recommended ROE for Montana-Dakota, I considered the following:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

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[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

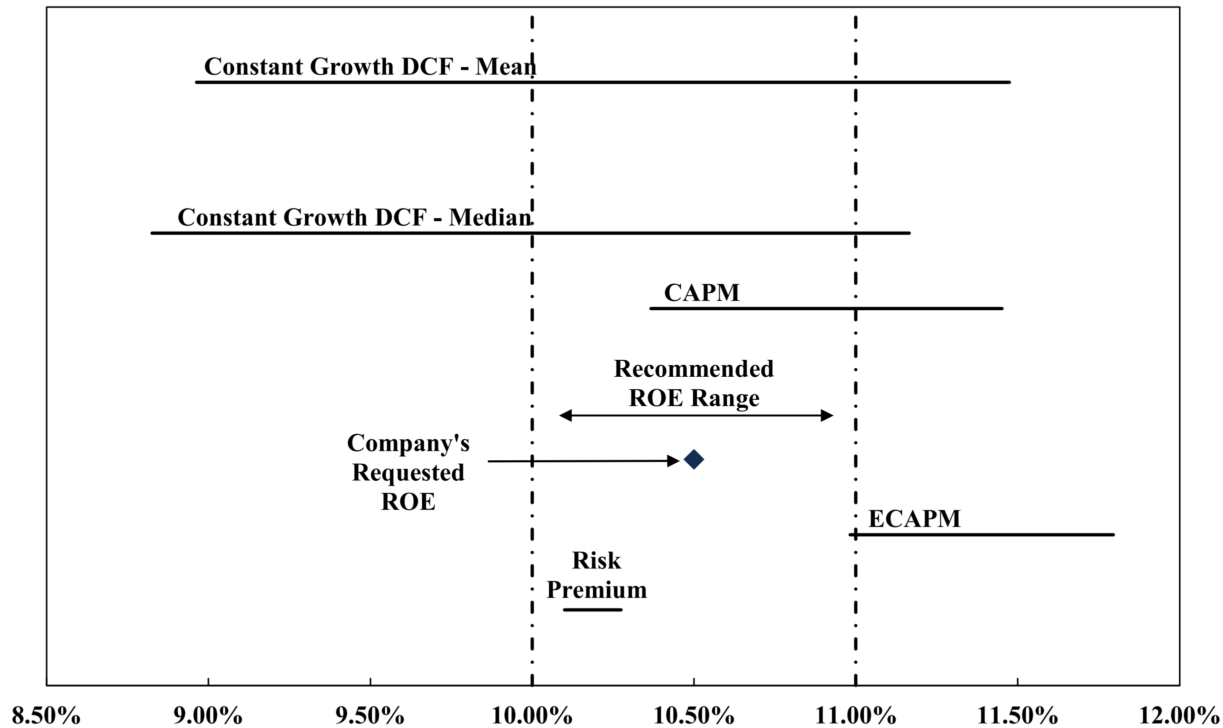
- The effect of current and projected capital market conditions on cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q9. What are the results of the models that you have used to estimate the cost of equity for Montana-Dakota?

A9. Figure 1 summarizes the range of results produced by the constant growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses.[2]

[2] Exhibit No. ___(AEB-2), Schedule 2.

Figure 1: Summary of Cost of Equity Model Results



As shown in Figure 1 (and Exhibit No. ___(AEB-2), Schedule 2), the range of results produced by the cost of equity estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q10. Are prospective capital market conditions expected to affect the results of the COE for the Company during the period in which the rates established in this proceeding will be in effect?

A10. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.

- Long-term interest rates have increased substantially in the past year and are expected to remain elevated at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, it is likely that utility share prices will decline.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.
- Consequently, the results of the DCF model, which relies on current utility share prices, may understate the cost of equity during the period that the Company's rates will be in effect.
- Rating agencies have cited increased risk in the utility sector due to increased interest rates, inflation and elevated capital expenditures.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Company.

Q11. What is your recommended ROE for Montana-Dakota in this proceeding?

A11. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.00 percent to 11.00 percent is reasonable. Within my recommended range, the Company is requesting an ROE of 10.50 percent which is conservative considering the relative business and financial risk of Montana-Dakota to the proxy group and current and prospective market conditions.

Q12. Is the Company's requested capital structure reasonable?

A12. Yes. The Company's proposed equity ratio of 50.185 percent is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering the credit rating agencies concerns regarding the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and capital expenditures.

III. REGULATORY GUIDELINES

Q13. Please describe the guiding principles to be used in establishing the cost of equity for a regulated utility.

A13. The United States Supreme Court's precedent-setting *Hope and Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

Q14. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A14. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

[3] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

Q15. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A15. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other electric, natural gas, and water utilities can inhibit the utility's ability to attract capital for investment.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a subsidiary of MDU Resources, the Company competes with the other MDU Resources subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q16. Is the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A16. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q17. What is the standard for setting the ROE in any jurisdiction?

A17. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Montana-Dakota's natural gas operations in North Dakota.

Q18. What are your conclusions regarding regulatory guidelines?

A18. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. The models used to estimate the cost of equity rely on market data that are specific either to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses both current and projected market data, specifically stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE and the recommended ROE for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q20. What factors affect the cost of equity for regulated utilities in the current and prospective capital markets?

A20. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q21. What effect do current and prospective market conditions have on the cost of equity for Montana-Dakota?

A21. As discussed in more detail in the remainder of this section, the combination of persistently high inflation and the Federal Reserve's changes in monetary policy contribute to an expectation of an increase in the cost of the investor-required return. It is essential that these factors be considered in setting the forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased significantly from pandemic-related lows seen in 2020, are expected to continue to remain relatively high in direct response to the Federal Reserve's use of monetary policy to combat inflation. These market conditions are indicative of an increase in the cost of equity since (i) there is a strong historical inverse correlation between interest rates (i.e., yields on long-term government bonds) and the share prices of utility stocks (i.e., as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, and historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity in this proceeding is being estimated for the future period that the Company's rates will be in effect, and because the cost of equity is expected to increase over the near term for utilities, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, will likely understate the cost of equity during the future period that the Company's rates will be in effect.

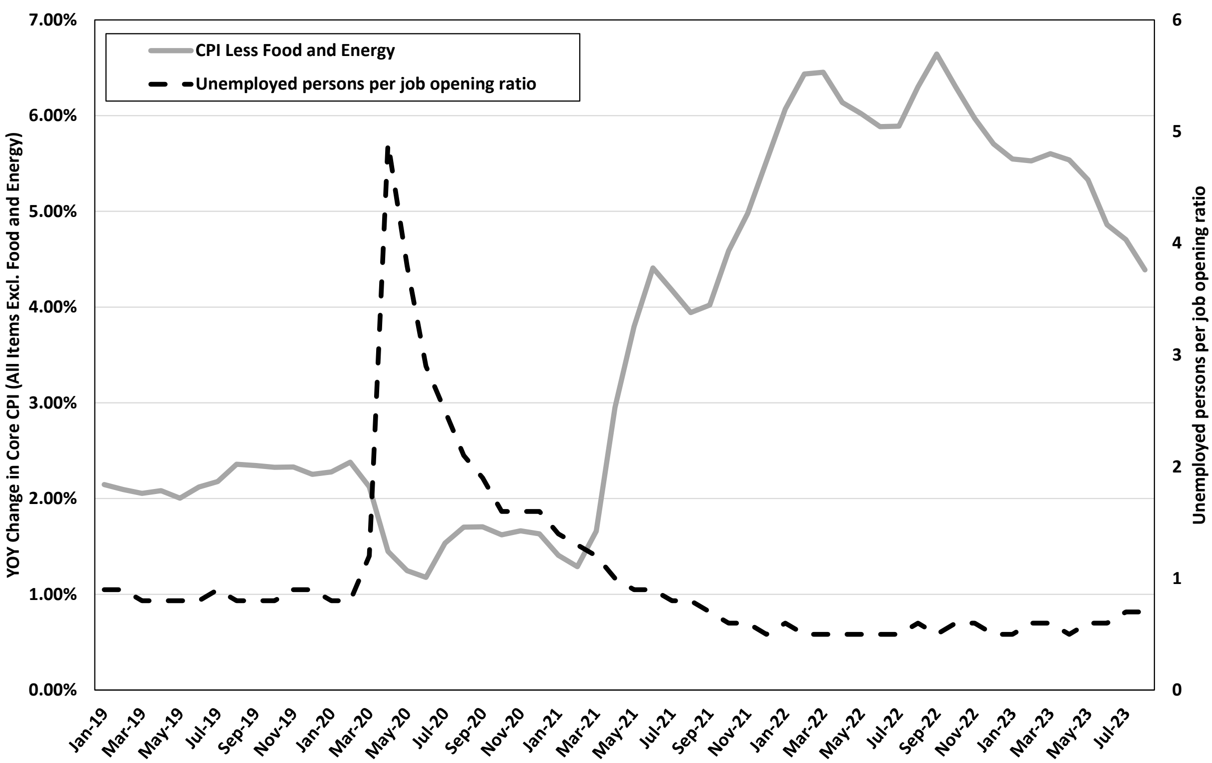
A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q22. Has inflation increased significantly over the past year?

A22. Yes. Figure 2 presents the year-over-year ("YOY") change in core inflation as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve since it removes the effect of food and energy prices, which can be highly volatile. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982. Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, core inflation continues to remain above the Federal Reserve's target level of 2.0 percent.

Finally, as shown in Figure 2, I also considered the ratio of unemployed persons per job opening which is currently 0.7 and has been consistently below 1.0 since 2021 despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to August 2023[4]



Q23. What are the expectations for inflation over the near-term?

A23. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level over at least the next year and that monetary policy will remain restrictive in order to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in September 2023 observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target:

> Inflation remains well above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [personal consumption expenditures] prices rose 3.4 percent over the 12 months

4 Bureau of Labor Statistics.

> ending in August; and that, excluding the volatile food and energy categories, core PCE prices rose 3.9 percent. Inflation has moderated somewhat since the middle of last year, and longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. Nevertheless, the process of getting inflation sustainably down to 2 percent has a long way to go. The median projection in the SEP for total PCE inflation is 3.3 percent this year, falls to 2.5 percent next year, and reaches 2 percent in 2026.[5]

As a result, Federal Reserve Chair Powell noted that they intend to maintain a restrictive policy stance until substantial progress has been made to reduce inflation to the long-term target of 2 percent.[6] Moreover, the Federal Reserve is currently forecasting an additional 25 basis point increase in the federal funds rate in 2023.[7] Given the expectation that monetary policy will remain restrictive, as noted previously, yields on long-term government bonds are expected to remain elevated over the near-term.

B. The Use of Monetary Policy to Address Inflation

Q24. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A24. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent.[8]

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5 Federal Reserve, Transcript of Chair Powell's Press Conference, September 20, 2023, p 2.

6 *Id.,* at 3.

7 Federal Reserve, Summary of Economic Projections, September 20, 2023, at 2.

8 Federal Reserve, Press Releases, March 16, 2022, May 4, 2022, June 15, 2022, September 22, 2022, November 2, 2022, February 1, 2023, March 22, 2023, May 3, 2023, July 26, 2023. Federal Reserve Board - Press Releases

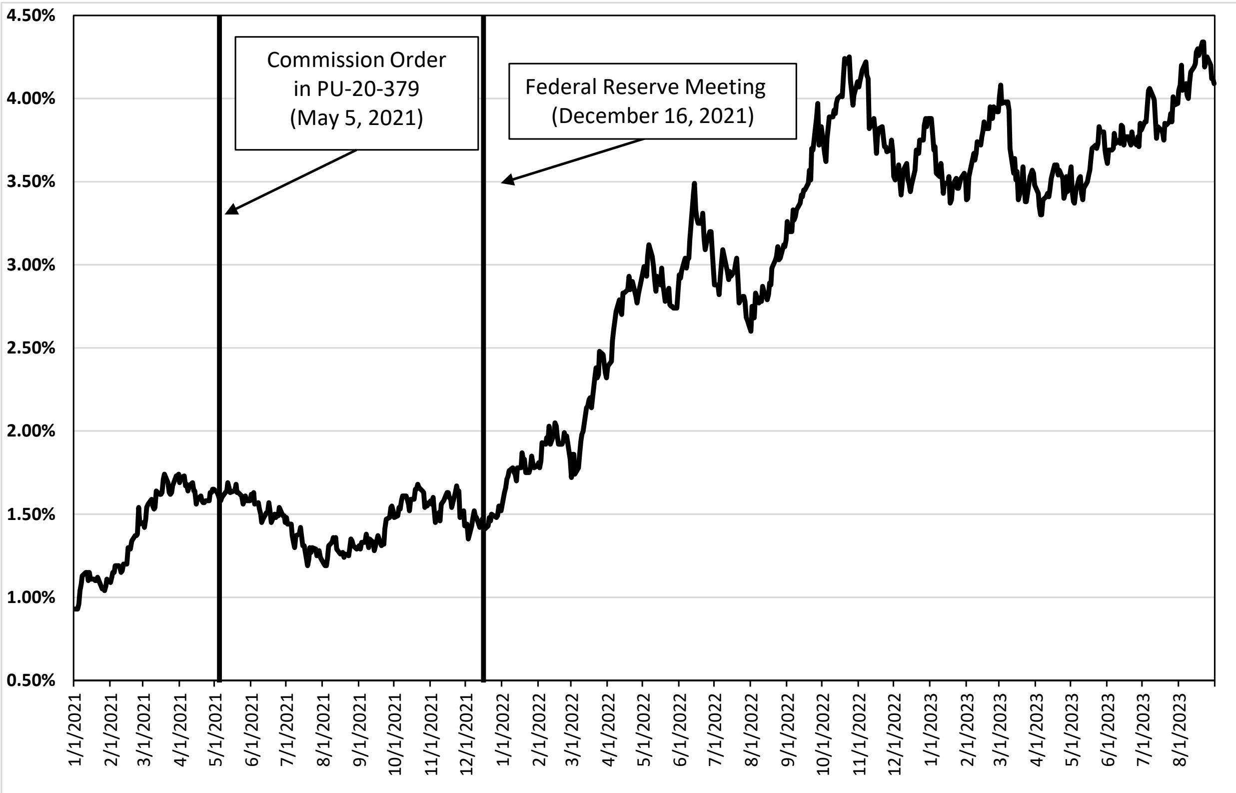
Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q25. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A25. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 3 below, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has more than doubled, increasing from 1.47 percent on December 15, 2021 to 4.09 percent at the end of August 2023. Further, since the Commission's order that approved the settlement agreement in the Company's last rate proceeding (Case No. PU-20-379) in May 2021, the 30-day average yield on the 10-year Treasury bond has increased from 1.64 percent to 4.11 percent, or 247 basis points.

Figure 3: 10-Year Treasury Bond Yield—Janaury 2021through August 31, 2023[9]



Q26. What have equity analysts said about long-term government bond yields?

A26. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the first quarter of 2025. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.80 percent through the first quarter of 2025.[10] It is reasonable to expect that if government bond yields remain elevated, the cost of equity will be increasing above the levels experienced in the 2020 and 2021 lower interest rate environment.

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9 S&P Capital IQ Pro.

10 *Blue Chip Financial Forecasts*, Vol. 42, No. 9, September 1, 2023.

Q27. How have interest rates and inflation changed since the Company's last rate case?

A27. As shown in Figure 4, when the Commission approved the settlement agreement authorizing an ROE of 9.30 percent in the Company's 2020 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 2.31 percent and core inflation was 3.80 percent. However, since the Company's 2020 rate proceeding, long-term interest rates have increased by approximately 190 basis points as the Federal Reserve has increased the federal funds rate to combat inflation, which, as shown, is also higher than during the Company's last rate case, and, as noted, remains above the Federal Reserve's target.

Figure 4: Change in Market Conditions Since Montana-Dakota's Last Rate Case[11]

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
C-PU-20-379	5/5/2021	0.06%	2.31%	3.80%	9.30%
Current	8/31/2023	5.33%	4.21%	4.39%	

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q28. Are utility share prices correlated to changes in the yields on long-term government bonds?

A28. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman

11 St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[12]

Q29. How do equity analysts expect the utility sector to perform in an increasing interest rate environment?

A29. Equity analysts project that utilities will underperform the broader market given the increases in interest rates. Fidelity classifies the utility sector as underweight,[13] and Bank of American recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[14]

Q30. Why do equity analysts expect the utility sector to underperform over the near-term?

A30. While interest rates have increased substantially over the past year, the valuations of utilities have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through August 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds. As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-

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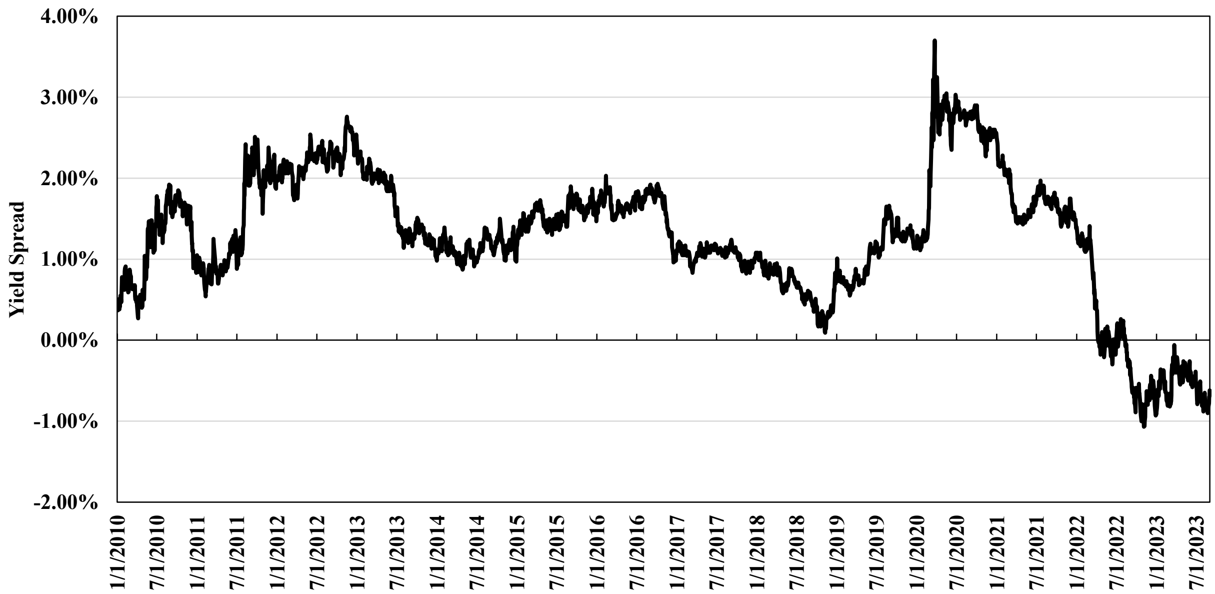
12 Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

13 Fidelity. "Third Quarter 2023 Investment Research Update." July 24, 2023.

14 Dumoulin-Smith, "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," September 6, 2023.

term government bonds exceeding the dividend yields of utilities. The yield spread as of August 31, 2023 was negative 0.62 percent. However, the long-term average yield spread from 2010 to 2023 is 1.27 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – August 2023[15]



Q31. Do you have any further context as to how unlikely it is to have a negative yield spread of this magnitude?

A31. Yes. For further context as to how unlikely it is to have a yield spread of negative 0.62 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of negative 0.62 percent has a z-score of -2.32, a yield spread of negative 0.62 percent is over 2 standard deviations from the mean of 1.27 percent.[16] In other words, 95 percent of the daily yield spread observations from 2010 through August 2023 fall between -0.36 percent and 2.91 percent, with the current yield spread of negative 0.62 percent being outside of that range. Thus,

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[15] S&P Capital IQ Pro and Bloomberg Professional.

[16] The z-score is calculated as: (yield spread at August 31, 2023 minus average yield spread 2010 through August 2023)/standard deviation of yield spread from 2010 through August 2023. This equals: (-0.0062 minus 0.0127)/0.0082.

the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

Q32. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A32. If interest rates remain relatively high as expected, then the share prices of utilities would be expected to decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity.

E. Conclusion

Q33. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A33. Investors expect long-term interest rates to remain relatively high through 2024 in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already greater than utility stock dividend yields, the share prices of utilities are likely to continue to decline, which is the reason a number of equity analysts have classified the sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

V. PROXY GROUP SELECTION

Q34. Please provide a brief profile of Montana-Dakota.

A34. Montana-Dakota Utilities Co. is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"). MDU provides natural gas distribution service across eight states through the Company, including its division Great Plains Natural Gas Co., and its affiliates Cascade Natural Gas Corp. and Intermountain Gas Company. In total, MDU serves approximately 1.03 million natural gas customers. Specifically, the Company provides service to approximately 115,521 natural gas customers in North Dakota[17], and the Company's North Dakota natural gas operations accounted for approximately 16 percent of MDU's total retail gas sales revenue in 2022.[18] The Company also provides vertically-integrated electric utility service in South Dakota, North Dakota, Montana, and Wyoming, serving approximately 144,500 customers. Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Developing) from S&P[19] and BBB+ (Outlook: Stable) from Fitch.[20]

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[17] Montana-Dakota Utilities, 2022 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 6.

[18] MDU Resources Group, Inc. Form 10-K for the fiscal year ended December 31,2022, at 15.

[19] Source: S&P Capital IQ Pro, (accessed September 28, 2023).

[20] Source: FitchRatings, (accessed September 28, 2023).

Q35. Why have you used a group of proxy companies to estimate the cost of equity for the Company?

A35. One of the purposes of this proceeding is to estimate the cost of equity for a utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and Montana-Dakota's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if Montana-Dakota was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for the Company.

Q36. How did you select the companies included in your proxy group?

A36. I began with the group of 10 publicly traded companies that Value Line classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends that have not been reduced in the last three years, since companies that do not pay dividends cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;

- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and,
- were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size against establishing a proxy group of companies that are comparable in business and financial risk to the Company.

Q37. What is the composition of your proxy group?

A37. The screening criteria discussed above is shown in Exhibit No. ___(AEB-2), Schedule 3, and resulted in a proxy group consisting of the companies shown Figure 6 below.

Figure 6: Natural Gas Utility Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q38. Please briefly discuss the ROE in the context of the regulated rate of return.

A38. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q39. How is the required cost of equity determined?

A39. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q40. What methods did you use to establish your recommended ROE in this proceeding?

A40. I considered the results of the constant growth DCF model, the CAPM, the ECAPM, and the BYRP analyses. As discussed in more detail below, a reasonable cost of equity estimate considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q41. Is it important to use more than one analytical approach to estimate the cost of equity?

A41. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and we use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[21] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[22] recommend the CAPM, DCF, and BYRP approaches.

Q42. Do current market conditions increase the importance of using more than one analytical approach?

A42. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. While the share prices of utilities have declined, the negative yield spread noted above is an indication that the share prices have not declined sufficiently to account for the recent rise in interest rates. As a result, equity analysts expect the utility sector to continue to underperform over the next year. Given the expected underperformance, it is reasonable to conclude that the DCF model is likely understating the forward-looking cost of equity because the model relies on historical share prices. The

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21 Copeland, Tom, Tim Koller and Jack Murrin. Valuation: Measuring and Managing the Value of Companies. New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

22 Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses offer some balance through the use of interest rates as a direct input into the models and therefore may better reflect the market conditions expected when the Company's rates are in effect. These recent changes in market conditions highlight the benefit of using multiple models since each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. It is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q43. Please describe the DCF approach.

A43. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q44. What assumptions are required for the constant growth DCF model?

A44. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q45. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A45. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended August 31, 2023.

Q46. Why did you use 30-, 90-, and 180-day averaging periods?

A46. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q47. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A47. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q48. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A48. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the constant growth DCF model.

Q49. Which sources of long-term earnings growth rates did you use?

A49. My constant growth DCF model incorporates three sources of long-term earnings per share ("EPS") growth rates: (1) Zacks Investment Research ("Zacks"); (2) Yahoo! Finance; and (3) Value Line.

Q50. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A50. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q51. How did you calculate the range of results for the constant growth DCF models?

A51. I calculated the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the Zacks, Yahoo! Finance, and Value Line projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculated results using the average growth rate from all three sources for each proxy group company.

Q52. What were the results of your constant growth DCF analyses?

A52. Figure 7 (see also Exhibit No. ___(AEB-2), Schedule 4) summarizes the results of my DCF analyses. As shown, the mean/median DCF results using the average growth rates range from 9.86 percent to 10.12 percent, and the mean/median results using the maximum growth rates range from 10.97 percent to 11.56 percent. While I also summarize the mean DCF results using the minimum growth rates, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 7: Constant Growth Discounted Cash Flow Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.05%	10.12%	11.56%
90-Day Avg. Stock Price	8.95%	10.02%	11.47%
180-Day Avg. Stock Price	8.89%	9.96%	11.40%
Average	8.96%	10.03%	11.47%
Median Results:			
30-Day Avg. Stock Price	9.04%	9.86%	11.35%
90-Day Avg. Stock Price	8.81%	9.90%	11.18%
180-Day Avg. Stock Price	8.63%	9.95%	10.97%
Average	8.83%	9.90%	11.16%

Q53. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of relatively high inflation and elevated interest rates?

A53. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") concluded that the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided

> by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[23]
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[24]

More recently, the Massachusetts Department of Public Utilities ("MDPU") also recently came to a similar conclusion:

> The Department recently considered the relationship between low interest rates and utility stock prices over the last several years and whether a projected increase in long-term interest rates caused the DCF analysis to understate the cost of equity. D.P.U. 20-120, at 416-419. The Department found that, although utility stocks had increased above historic levels in conjunction with low interest rates, the evidence in that proceeding that long-term interest rates would change was speculative. D.P.U. 20-120, at 417-419. In this proceeding, the record is clear that long-term interest rates have increased compared to the period of time from which the parties derived the dividend yields used in the DCF analyses (Exh. ES-VVR-Rebutal-1, at 23-26; Tr. 14, at 1463). We also have considered the Attorney General's evidence of investors forecasting that utility stocks will retain

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[23] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

[24] *Id.*, pp. 177–178.

> their high valuations in the near term (Tr. 14, at 1449-1452; RR-DPU-48). ***Based on the foregoing evidence, the Department finds that there is greater certainty that the DCF results understate the Company's cost of equity.***[25]

Q54. What are your conclusions about the results of the DCF models?

A54. As discussed previously, one primary assumption of the DCF model is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF model with caution. Therefore, while I have given weight to the results of the DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

C. CAPM Analysis

Q55. Please briefly describe the CAPM.

A55. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, systematic risk of that security. Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components:

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[25] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, November 30, 2022, p. 385-386; emphasis added.

$$K_e = r_f + \beta(r_m\text{-}r_f) \quad [3]$$

Where:

K_e = the required market cost of equity;
β = beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined a:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q56. What risk-free rate do you use in your CAPM analysis?

A56. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds, which is 4.21 percent;[26] (2) the average projected 30-year Treasury bond yield for the fourth quarter of 2023 through the fourth quarter of 2024, which

[26] Bloomberg Professional as of August 31, 2023.

is 4.04 percent;[27] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029, which is 3.80 percent.[28]

Q57. What beta coefficients do you use in your CAPM analysis?

A57. As shown Exhibit No. ___(AEB-2), Schedule 5, I use the beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The Value Line beta coefficients are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Additionally, as shown in shown Exhibit No. ___(AEB-2), Schedule 5, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group. As shown in Exhibit No. ___(AEB-2), Schedule 6, the long-term average utility Beta coefficient was calculated as an average of the Value Line beta coefficients for the companies in my proxy group from 2013 through 2022.

Q58. How do you estimate the market risk premium in the CAPM?

A58. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit No. ___(AEB-2), Schedule 7, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.61 percent and a weighted long-term growth rate of 11.13 percent, the estimated required market return for the S&P 500 Index

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27 *Blue Chip Financial Forecasts*, Vol. 42, No. 9, September 1, 2023, at 2.

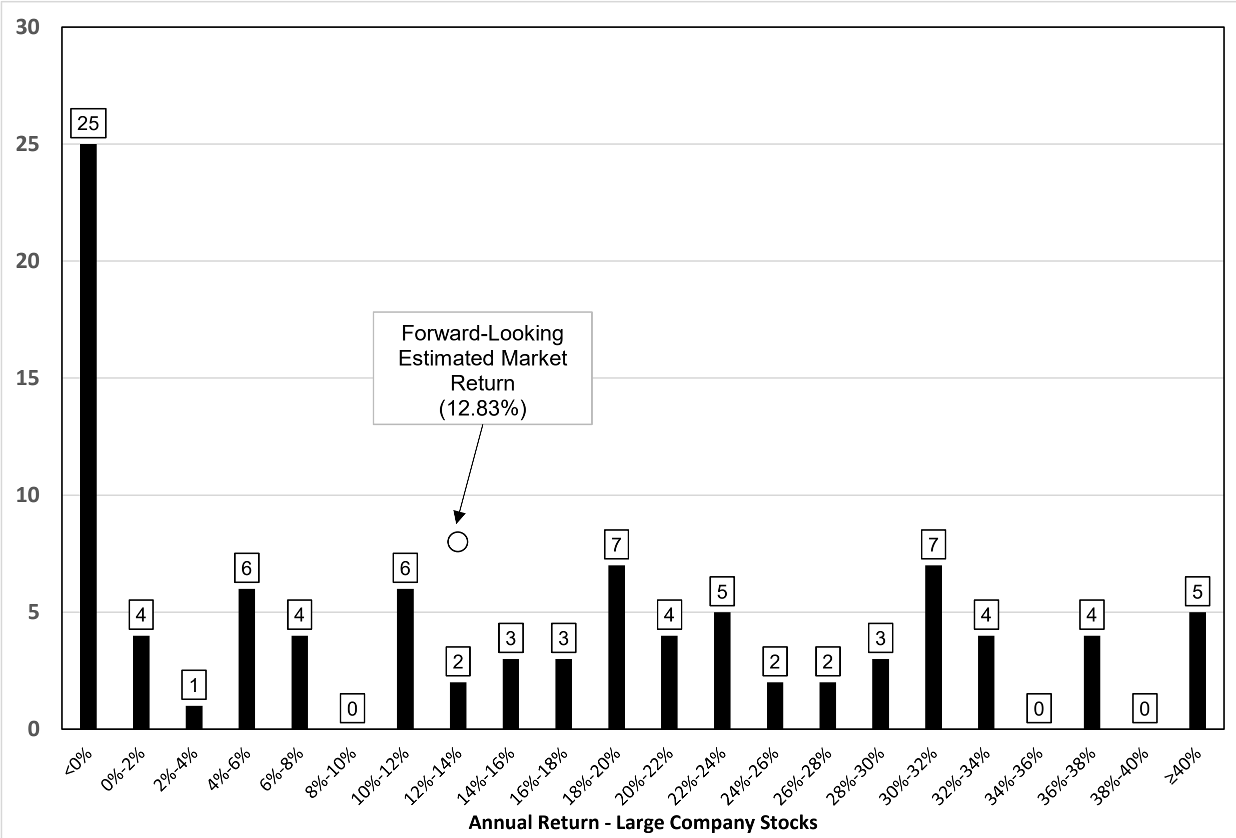
28 *Blue Chip Financial Forecasts*, Vol. 42, No. 6, June 1, 2023, at 14.

as of August 31, 2023 is 12.83 percent. As shown in Exhibit No. ___(AEB-2), Schedule 5, based on the three risk-free rates considered, the market risk premium ranges from 8.62 percent to 9.03 percent.

Q59. How does the current expected market return compare to observed historical market returns?

A59. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.83 percent is not unreasonable. In 50 out of the past 97 years (or approximately 52 percent of observations), the realized equity market return was at least 12.83 percent or greater.

Figure 8: Realized U.S. equity market returns (1926-2022)[29]



Q60. Did you consider another form of the CAPM in your analysis?

A60. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[30] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

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[29] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

[30] *See, e.g.*, Morin, Roger A. New Regulatory Finance. Public Utilities Reports, Inc., 2006, at 189.

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:
k_e = the required market cost of equity;
β = Adjusted beta coefficient of an individual security;
rf = the risk-free rate of return; and
r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[31]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current Bloomberg, current Value Line, and long-term Value Line beta coefficients.

Q61. What are the results of your CAPM analyses?

A61. As shown in Figure 9 (see also Exhibit No. ___(AEB-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.37 percent to 11.45 percent. The ECAPM analysis results range from 10.98 percent to 11.80 percent.

[31] *Id.* at 191.

Figure 9: CAPM and ECAPM Results

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current Value Line Beta	11.45%	11.42%	11.39%
Current Bloomberg Beta	10.78%	10.74%	10.68%
Long-term Avg. Value Line Beta	10.48%	10.43%	10.37%
ECAPM:			
Current Value Line Beta	11.80%	11.78%	11.75%
Current Bloomberg Beta	11.29%	11.26%	11.22%
Long-term Avg. Value Line Beta	11.07%	11.03%	10.98%

D. BYRP Analysis

Q62. Please describe the BYRP analysis.

A62. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q63. What is the fundamental relationship between the equity risk premium and interest rates?

A63. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis provided in Exhibit No. ___(AEB-2), Schedule 8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[32]

Q64. Is the BYRP analysis relevant to investors?

A64. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

[32] *See e.g.*, Berry, S. Keith. "Interest Rate Risk and Utility Risk Premia during 1982-93." Managerial and Decision Economics, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

Q65. What did your BYRP analysis reveal?

A65. As shown in Figure 10, from 1992 through August 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

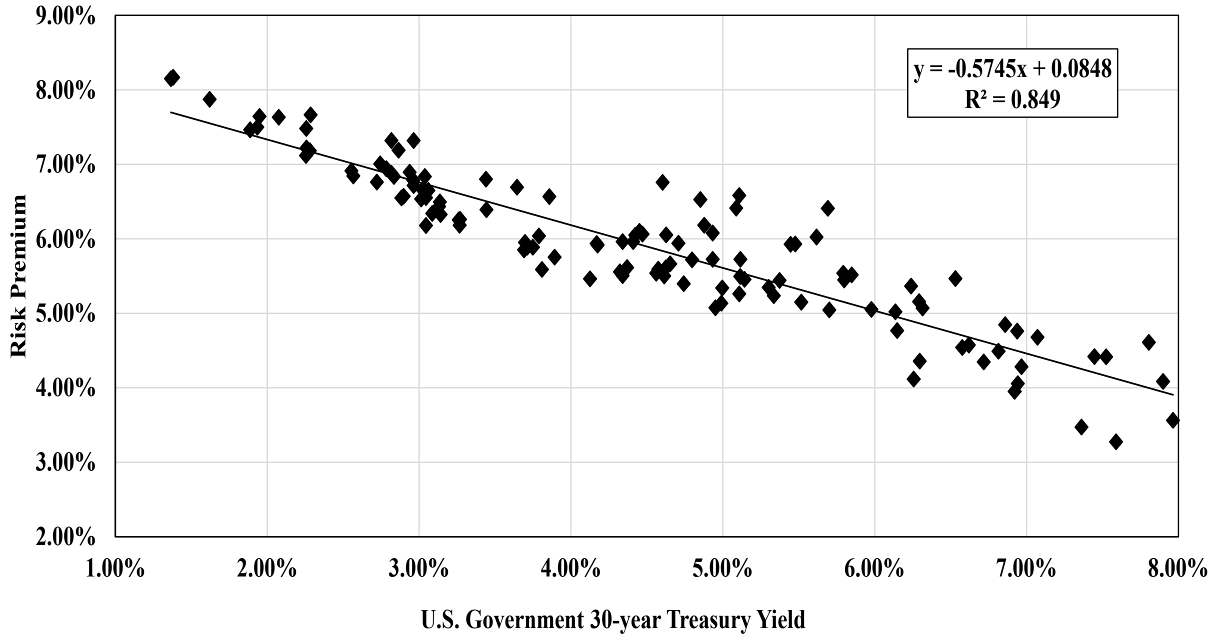
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from all natural gas utility rate cases from 1992 through August 2023 as reported by Regulatory Research Associates ("RRA").[33] This equation's coefficients were statistically significant at the 99.00 percent level.

[33] This analysis was screened to eliminate limited issue rider cases, transmission cases and cases that were silent with respect to the authorized ROE.

Figure 10: Risk Premium Regression Analysis



Q66. What are the results of your BYRP analysis?

A66. The results of my BYRP analysis are shown in Figure 11 (and on Exhibit No. ___(AEB-2), Schedule 8).

Figure 11: Risk Premium Results

	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield	4.21%	6.06%	10.27%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024)	4.04%	6.16%	10.20%
Blue Chip Long-Term Projected Forecast (2025-2029)	3.80%	6.30%	10.10%
Average			10.19%

Q67. How did the results of the BYRP analysis inform your recommended ROE for the Company?

A67. I have considered the results of the BYRP analysis in setting my recommended ROE for Montana-Dakota's natural gas operations in North Dakota. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VII. REGULATORY AND BUSINESS RISKS

Q68. Taken alone, do the results of the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A68. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size Risk

Q69. Is there a risk to a firm associated with small size?

A69. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[34]

[34] Annin, Michael. "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Q70. How does the smaller size of a utility affect its business risk?

A70. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q71. How do Montana-Dakota's natural gas operations in North Dakota compare in size to the proxy group companies?

A71. Montana-Dakota's natural gas operations in North Dakota are substantially smaller than the median for the proxy group companies in terms of market capitalization. While Montana-Dakota is not publicly traded on a stand-alone basis, as shown on Exhibit No. ___(AEB-2), Schedule 9, I have estimated the implied market capitalization for the Company (*i.e.*, the market capitalization if the Company were a stand-alone publicly-traded entity) relative to the actual market capitalization for the proxy group companies.

Specifically, to estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculated the equity component of the Company's capital structure by multiplying the Company's test year rate base of $216.97 million by the Company's proposed common equity ratio in this proceeding of 50.185 percent. I then applied the median market-to-book ratio for the proxy group of 1.60 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $174.15 million, or just 4.10 percent of the median market capitalization for the proxy group.

Q72. How did you estimate the size premium for Montana-Dakota?

A72. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[35] As shown on Exhibit No. ___(AEB-2), Schedule 9, the median market capitalization of the proxy group is approximately $4.25 billion, which corresponds to the fourth decile of *Kroll's* market capitalization data.[36] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.58 percent (*i.e.*, 58 basis points). In comparison, the Company's implied market capitalization of approximately $174.15 million falls within the 10th decile, which corresponds to a size premium of 4.83 percent (*i.e.*, 483 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 425 basis points (*i.e.*, 4.83 percent minus 0.58 percent)

Q73. Were utility companies included in the size premium study conducted by *Kroll*?

A73. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies

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[35] *Kroll* Cost of Capital Navigator – Size Premium; annual data as of December 31, 2022.

[36] *Id*.

contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[37]

Q74. Is the size premium applicable to companies in regulated industries such as utilities?

A74. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[38] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[39]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[40] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly

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[37] *Kroll*. Valuation Handbook: Guide to Cost of Capital. 2019, Exhibit 7.2.

[38] Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." The Quarterly Review of Economics and Finance, Vol. 43, No. 3, 2003, at 578–582.

[39] *Id*.

[40] Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011.

included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[41]

Q75. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A75. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk." [42] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[43] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[44] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the

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41 *Id.*

42 Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

43 *Id.*, at 32 and 37.

44 Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

> record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[45]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[46]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[47]

Q76. How have you considered the smaller size of Montana-Dakota's natural gas distribution operations in North Dakota in your recommended ROE?

A76. While I have estimated the effect of the Company's small size of its natural gas operations in North Dakota on the cost of equity, I am not proposing a specific adjustment for this risk

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[45] *Id.*

[46] Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

[47] *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

factor. Rather, I believe it is important to consider the small size of the Company's utility operations in the determination of where, within the range of analytical results, Montana-Dakota's required cost of equity falls. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. Flotation Cost

Q77. What are flotation costs?

A77. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q78. Why is it important to consider flotation costs in the authorized ROE?

A78. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q79. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A79. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation costs are incurred prior to the test year but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny the Company the opportunity to earn its required rate of return in the future.

Q80. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A80. Assume MDU issues stock with a value of $100, and an equity investor invests $100 in MDU in exchange for that stock. Further, suppose that after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q81. Is the date of MDU's last issuance of common equity important in the determination of flotation costs?

A81. No. As shown in Exhibit No. ___(AEB-2), Schedule 10, MDU closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. However, it is important to recognize flotation costs for all equity issuances since these costs reduce the permanent capital structure of the company. Therefore, the vintage of the issuance is not particularly important because an investor should have a reasonable opportunity to earn a return on the full amount of capital that she has contributed in every year of the investment. As noted in my earlier example, the investor contributed $100, but due to flotation costs, MDU only ends up with $97 to invest in rate base. Without the recognition of flotation costs, the investor will only earn a return on the $97 invested in rate base in year 1 as well as every subsequent year of the investment. Therefore, adjusting the ROE in year 1 to recognize flotation costs will only award the opportunity for the investor to earn a return on her full investment in year 1 and then in year 2 and after the investor will still only earn a return on the $97 invested in rate base. As a result, the ROE should be adjusted for flotation costs in every year regardless of the vintage of the issuance because as long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q82. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A82. No, it is not. Although the Company is a wholly-owned subsidiary of MDU, it is appropriate to consider flotation costs. Wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund utility operations and inhibits the utility's ability to obtain new equity capital at a reasonable cost. This is particularly important in the current circumstance given that the Company is planning significant capital expenditures in the near term.

Q83. Is the need to consider flotation costs recognized by the academic and financial communities?

A83. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[48]

Further, Dr. Myron Gordon recognized that the DCF model did not include the cost of floating a new stock issue and proposed a means for regulators to recognize these costs in his text on the subject.[49]

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48 Pratt, Shannon P. Cost of Capital Estimation and Applications. Second Edition, at 220-21.

49 Gordon, Myron, "The Cost of Capital to a Public Utility", 1974, pp. 164-166.

Q84. Have you estimated what a reasonable flotation cost adjustment would be for Montana-Dakota?

A84. Yes. My flotation cost is estimated on the costs of issuing equity that were incurred by MDU in its two most recent common equity issuances. As shown in Exhibit No. ___(AEB-2), Schedule 10, based on the flotation costs of those two issuances, the impact on the proxy group's cost of equity amounts to 10 basis points (i.e., 0.10 percent) based on the median and 15 basis points (i.e., 0.15 percent) based on the mean.

Q85. Do your final cost of equity model results include an adjustment for flotation cost recovery?

A85. No, I did not make an explicit adjustment for flotation costs to any of the quantitative results of my cost of equity models. Rather, I considered the incremental cost associated with stock issuance as part of my overall recommendations regarding the range of reasonable ROEs and ultimate recommended ROE.

C. Capital Expenditures

Q86. Please summarize the capital expenditure requirements for Montana-Dakota's natural gas distribution operations in North Dakota.

A86. As of December 31, 2022, the Company had net utility plant of approximately $214.24 million, and the Company currently projects capital expenditures for 2024 through 2028 of approximately $190.28 million. [50] Therefore, the Company's projected capital

[50] Data provided by the Company.

expenditures represent approximately 88.81 percent of its net utility plant as of December 31, 2022.

Q87. How is the Company's risk profile affected by its capital expenditure requirements?

A87. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q88. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A88. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those

> jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[51]

Therefore, to the extent that Montana-Dakota's rates do not permit the Company to recover its capital investments on a timely basis and provide a reasonable opportunity to earn its authorized return, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q89. How do Montana-Dakota's capital expenditure requirements compare to those of the proxy group companies?

A89. As shown in Exhibit No. ___(AEB-2), Schedule 11, I calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2028 by its total net utility plant as of December 31, 2022. As shown in Exhibit No. ___(AEB-2), Schedule 11, the Company's ratio of capital expenditures as a percentage of net utility plant is 88.81 percent, which is greater than the median for the proxy group companies of 63.30 percent. This result indicates a risk level for Montana-Dakota that is higher than the proxy group companies.

Q90. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures between rate cases?

A90. No. Montana-Dakota currently has not requested approval to recover capital investment costs between rate cases utilizing a capital tracking mechanism. The Company is proposing the use of a forecast test year ending December 31, 2024. As a result of the future test year,

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[51] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

the Company will be able to recover its projected capital expenditures for 2024 in the rates that are determined in this proceeding. Therefore, the Company will still rely on future rate case filings for its capital expenditures plan for 2025-2028. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No. ___(AEB-2), Schedule 12, 71.4 percent of the companies in the proxy group have some form of capital cost recovery mechanisms in place. While the Company is proposing a forecast test year, Montana-Dakota does not currently have a capital tracking mechanism to recover capital cost between rate cases and as a result the Company's risk relative to the proxy group is increased.

Q91. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A91. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures. Therefore, Montana-Dakota's capital expenditures plan and limited ability to recover the capital investment on an as incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

D. Regulatory Risk

Q92. How does the regulatory environment affect investors' risk assessments?

A92. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover invested capital and the market-required return on such capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, which balances the long-term interests of investors and customers. In that respect, the regulatory framework in which a utility operates is one of the most important factors considered in both debt and equity investors' risk assessments.

Because investors have many investment alternatives, even within a given market sector, the Company's authorized returns must be adequate on a relative basis to ensure their ability to attract capital under a variety of economic and financial market conditions. From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet their near-term financial obligations, make the capital investments needed to maintain and expand their systems, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also from efficient access to capital markets.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (that is, debt interest must be paid prior to any equity dividends), equity investors are particularly concerned with the regulatory framework in which a utility operates and its effect on future earnings and cash flows.

Q93. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A93. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[52]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[53] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[54]

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52 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

53 Standard & Poor's Global Ratings. Ratings Direct. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 2.

54 *Id.*

Q94. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A94. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[55] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[56]

Q95. Have you conducted an analysis to compare the cost recovery mechanisms of Montana-Dakota to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A95. Yes. I have evaluated the regulatory framework in North Dakota on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e., forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence

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[55] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

[56] *Id.*

of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No. ___(AEB-2), Schedule 12 and are summarized as follows:

Test Year Convention: Montana-Dakota is relying on a fully forecasted test year in North Dakota for the period January 1, 2024 through December 31, 2024. Similarly, approximately 52.4 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a forecasted test year.

Volumetric Risk: Montana-Dakota currently has some protection against volumetric risk in North Dakota through straight fixed-variable rates for the residential rate class and a weather normalization clause known as the Distribution Delivery Stabilization Mechanism ("DDSM") for its firm general service rate class. However, the Company is not proposing to continue the use of straight fixed-variable rates for the residential rate class and instead is proposing the use of the DDSM for both its firm general service and residential classes. Approximately, approximately 91 percent of the utility operating subsidiaries of the proxy group companies have some form of protection against volumetric risk either through formula rates plans, revenue decoupling or straight fixed-variable rate design.

Capital Cost Recovery: As noted, while the Company is proposing a forecast test year which will allow the Company to recover a portion of its capital expenditures plan from 2024 through 2028, the Company does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, approximately 71 percent of the operating utility subsidiaries of the proxy group companies have some form of capital cost recovery allowing for the recovery of capital investments placed into service between rate cases.

Q96. What is the effect on Montana-Dakota of having relatively fewer timely cost recovery mechanisms?

A96. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q97. Is there evidence that Montana-Dakota has been unable to earn its authorized ROE?

A97. Yes. As shown in Figure 12, Montana-Dakota's natural gas operations in North Dakota has significantly under-earned its authorized ROE in seven out of eight years since 2015. Over this period, the average earned ROE on the Company's natural gas operations in North Dakota was 7.55 percent, as compared with the average authorized ROE of 9.60 percent, for an average under-earning of 205 basis points per year. This under-earning occurred despite the fact that Montana-Dakota relied on a forecast test year and had partial protection of volumetric risk through straight fixed-variable rate design for the residential rate class and a weather normalization clause for its firm general service rate class.

Figure 12: Montana-Dakota's Earned vs. Authorized ROE (2015-2022)

	EARNED ROE	AUTHORIZED ROE	EARNINGS DIFFERENTIAL (BPS)
2015	8.09%	10.00%	-191
2016	7.74%	10.00%	-226
2017	6.62%	10.00%	-338
2018	9.44%	9.40%	4
2019	6.39%	9.40%	-301
2020	6.48%	9.40%	-292
2021	9.12%	9.30%	-18
2022	6.50%	9.30%	-280
Average	**7.55%**	**9.60%**	**-205**

Q98. What is your conclusion regarding the regulatory framework in North Dakota as compared with the jurisdictions in which the proxy group companies operate?

A98. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery through forecasted test years, capital cost recovery trackers and revenue stabilization mechanisms than Montana-Dakota has in North Dakota. Moreover, the Company has under-earned its authorized ROE in seven out of eight years since 2015. As a result, I conclude that the Company has greater than average regulatory risk when compared to the proxy group.

VIII. CAPITAL STRUCTURE

Q99. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A99. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. All else equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q100. What is Montana-Dakota's proposed capital structure?

A100. The Company is proposing to establish a capital structure consisting of 50.185 percent common equity, 45.296 percent long-term debt and 4.519 percent short-term debt.

Q101. Did you conduct an analysis to assess the reasonableness of the requested equity ratio?

A101. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the equity ratios for the Company.

Specifically, I calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No. ___(AEB-2), Schedule 13, the average common equity ratio for the operating subsidiaries of the proxy group companies ranged from 44.57 percent to 59.79 percent, with an average of 53.59 percent. Given that Montana-Dakota's proposed equity ratio of 50.185 percent is within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, I consider its proposed equity ratio to be reasonable.

Q102. Are there other factors to be considered in setting the Company's capital structure?

A102. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the outlook for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics, noting that constructive regulatory outcomes that promote timely cost recovery are a key factor in supporting utility credit quality.[57]

Fitch Ratings ("Fitch") also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that

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[57] Moody's Investors Service, Outlook. "Outlook turns stable on low natural gas prices and credit-supportive regulation." September 7, 2023.

there are some offsets in managing these headwinds that include but not limited to higher authorized ROEs.[58]

Likewise, while S&P recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[59]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for Montana-Dakota in the context of this proceeding

IX. CONCLUSIONS AND RECOMMENDATION

Q103. What is your conclusion regarding a fair ROE for the Company?

A103. Based on the various quantitative analyses summarized in Figure 13 and the qualitative analyses presented in my Direct Testimony, a reasonable range of ROE results for

[58] Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

[59] S&P Global Ratings. "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

Montana-Dakota is from 10.00 percent to 11.00 percent. Within that range, the Company is requesting an ROE of 10.50 percent which is conservative considering the business and financial risk of Montana-Dakota as compared to the proxy group as well as current and prospective capital market conditions.

Figure 13: Summary of Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.05%	10.12%	11.56%
90-Day Avg. Stock Price	8.95%	10.02%	11.47%
180-Day Avg. Stock Price	8.89%	9.96%	11.40%
Average	8.96%	10.03%	11.47%
Median Results:			
30-Day Avg. Stock Price	9.04%	9.86%	11.35%
90-Day Avg. Stock Price	8.81%	9.90%	11.18%
180-Day Avg. Stock Price	8.63%	9.95%	10.97%
Average	8.83%	9.90%	11.16%

CAPM / ECAPM / Bond Yield Risk Premium

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current Value Line Beta	11.45%	11.42%	11.39%
Current Bloomberg Beta	10.78%	10.74%	10.68%
Long-term Avg. Value Line Beta	10.48%	10.43%	10.37%
ECAPM:			
Current Value Line Beta	11.80%	11.78%	11.75%
Current Bloomberg Beta	11.29%	11.26%	11.22%
Long-term Avg. Value Line Beta	11.07%	11.03%	10.98%
Bond Yield Risk Premium:	10.27%	10.20%	10.10%

Q104. What is your conclusion regarding the Company's proposed capital structure?

A104. My conclusion is that Montana-Dakota's proposal to establish a capital structure for ratemaking purposes consisting of 50.185 percent common equity, 45.296 percent long-term debt, and 4.519 percent short-term debt is reasonable when compared to the capital structures of the utility operating subsidiaries of the proxy group companies and taking in consideration the effect of inflation, high interest rates and increased capital expenditures on the cash flows, and therefore should be adopted.

Q105. Does this conclude your direct testimony?

A105. Yes, it does.

Ann E. Bulkley

PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-______-______-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-____	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

SUMMARY OF COE ANALYSES RESULTS

	Constant Growth DCF		
	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.05%	10.12%	11.56%
90-Day Avg. Stock Price	8.95%	10.02%	11.47%
180-Day Avg. Stock Price	8.89%	9.96%	11.40%
Average	8.96%	10.03%	11.47%
Median Results:			
30-Day Avg. Stock Price	9.04%	9.86%	11.35%
90-Day Avg. Stock Price	8.81%	9.90%	11.18%
180-Day Avg. Stock Price	8.63%	9.95%	10.97%
Average	8.83%	9.90%	11.16%

	CAPM / ECAPM / Bond Yield Risk Premium		
	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current Value Line Beta	11.45%	11.42%	11.39%
Current Bloomberg Beta	10.78%	10.74%	10.68%
Long-term Avg. Value Line Beta	10.48%	10.43%	10.37%
ECAPM:			
Current Value Line Beta	11.80%	11.78%	11.75%
Current Bloomberg Beta	11.29%	11.26%	11.22%
Long-term Avg. Value Line Beta	11.07%	11.03%	10.98%
Bond Yield Risk Premium:	10.27%	10.20%	10.10%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P or Moody's Investment Grade Credit Rating	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A-	Yes	Yes	100.00%	66.03%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	100.17%	65.58%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	99.84%	91.01%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100.00%	100.00%	No
Spire, Inc.	SR	Yes	A-	Yes	Yes	86.84%	100.00%	No

Notes:
[1]-[2]: Bloomberg Professional
[3]: Yahoo! Finance, and Zacks
[4]: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5]-[6]: Form 10-K's for 2022, 2020, and 2021
[7]: S&P Capital IQ news releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$118.09	2.51%	2.60%	7.00%	7.50%	7.30%	7.27%	9.59%	9.86%	10.10%
NiSource Inc.	NI	$1.00	$26.94	3.71%	3.86%	9.50%	6.70%	7.00%	7.73%	10.54%	11.59%	13.39%
Northwest Natural Gas Company	NWN	$1.94	$41.31	4.70%	4.80%	6.50%	2.80%	3.70%	4.33%	7.56%	9.13%	11.35%
ONE Gas, Inc.	OGS	$2.60	$76.19	3.41%	3.51%	6.50%	5.00%	5.00%	5.50%	8.50%	9.01%	10.02%
Spire, Inc.	SR	$2.88	$60.77	4.74%	4.88%	8.00%	n/a	4.20%	6.10%	9.04%	10.98%	12.93%
Mean										9.05%	10.12%	11.56%
Median										9.04%	9.86%	11.35%

Notes:
[1] Bloomberg Professional as of August 31, 2023
[2] Bloomberg Professional 30-day average as of August 31, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Yahoo! Finance Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$116.58	2.54%	2.63%	7.00%	7.50%	7.30%	7.27%	9.63%	9.90%	10.13%
NiSource Inc.	NI	$1.00	$27.20	3.68%	3.82%	9.50%	6.70%	7.00%	7.73%	10.50%	11.55%	13.35%
Northwest Natural Gas Company	NWN	$1.94	$42.80	4.53%	4.63%	6.50%	2.80%	3.70%	4.33%	7.40%	8.96%	11.18%
ONE Gas, Inc.	OGS	$2.60	$77.55	3.35%	3.44%	6.50%	5.00%	5.00%	5.50%	8.44%	8.94%	9.96%
Spire, Inc.	SR	$2.88	$63.74	4.52%	4.66%	8.00%	n/a	4.20%	6.10%	8.81%	10.76%	12.70%
Mean										8.95%	10.02%	11.47%
Median										8.81%	9.90%	11.18%

Notes:
[1] Bloomberg Professional as of August 31, 2023
[2] Bloomberg Professional 90-day average as of August 31, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$114.42	2.59%	2.68%	7.00%	7.50%	7.30%	7.27%	9.68%	9.95%	10.18%
NiSource Inc.	NI	$1.00	$27.08	3.69%	3.84%	9.50%	6.70%	7.00%	7.73%	10.52%	11.57%	13.37%
Northwest Natural Gas Company	NWN	$1.94	$44.85	4.33%	4.42%	6.50%	2.80%	3.70%	4.33%	7.19%	8.75%	10.97%
ONE Gas, Inc.	OGS	$2.60	$77.47	3.36%	3.45%	6.50%	5.00%	5.00%	5.50%	8.44%	8.95%	9.97%
Spire, Inc.	SR	$2.88	$66.43	4.34%	4.47%	8.00%	n/a	4.20%	6.10%	8.63%	10.57%	12.51%
Mean										8.89%	9.96%	11.40%
Median										8.63%	9.95%	10.97%

Notes:
[1] Bloomberg Professional as of August 31, 2023
[2] Bloomberg Professional 180-day average as of August 31, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.21%	0.85	12.83%	8.62%	11.54%	11.86%
NiSource Inc.	NI	4.21%	0.90	12.83%	8.62%	11.97%	12.18%
Northwest Natural Gas Company	NWN	4.21%	0.80	12.83%	8.62%	11.11%	11.54%
ONE Gas, Inc.	OGS	4.21%	0.80	12.83%	8.62%	11.11%	11.54%
Spire, Inc.	SR	4.21%	0.85	12.83%	8.62%	11.54%	11.86%
Mean						11.45%	11.80%
Median						11.54%	11.86%

Notes:
[1] Source: Bloomberg Professional 30-day average as of August 31, 2023
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.04%	0.85	12.83%	8.79%	11.51%	11.84%
NiSource Inc.	NI	4.04%	0.90	12.83%	8.79%	11.95%	12.17%
Northwest Natural Gas Company	NWN	4.04%	0.80	12.83%	8.79%	11.07%	11.51%
ONE Gas, Inc.	OGS	4.04%	0.80	12.83%	8.79%	11.07%	11.51%
Spire, Inc.	SR	4.04%	0.85	12.83%	8.79%	11.51%	11.84%
Mean						11.42%	11.78%
Median						11.51%	11.84%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 9, September 1, 2023, at 2
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.85	12.83%	9.03%	11.48%	11.81%
NiSource Inc.	NI	3.80%	0.90	12.83%	9.03%	11.93%	12.15%
Northwest Natural Gas Company	NWN	3.80%	0.80	12.83%	9.03%	11.02%	11.48%
ONE Gas, Inc.	OGS	3.80%	0.80	12.83%	9.03%	11.02%	11.48%
Spire, Inc.	SR	3.80%	0.85	12.83%	9.03%	11.48%	11.81%
Mean						11.39%	11.75%
Median						11.48%	11.81%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.21%	0.75	12.83%	8.62%	10.66%	11.20%
NiSource Inc.	NI	4.21%	0.81	12.83%	8.62%	11.23%	11.63%
Northwest Natural Gas Company	NWN	4.21%	0.70	12.83%	8.62%	10.24%	10.89%
ONE Gas, Inc.	OGS	4.21%	0.78	12.83%	8.62%	10.96%	11.42%
Spire, Inc.	SR	4.21%	0.76	12.83%	8.62%	10.79%	11.30%
Mean						10.78%	11.29%
Median						10.79%	11.30%

Notes:
[1] Source: Bloomberg Professional 30-day average as of August 31, 2023
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.04%	0.75	12.83%	8.79%	10.62%	11.17%
NiSource Inc.	NI	4.04%	0.81	12.83%	8.79%	11.20%	11.61%
Northwest Natural Gas Company	NWN	4.04%	0.70	12.83%	8.79%	10.19%	10.85%
ONE Gas, Inc.	OGS	4.04%	0.78	12.83%	8.79%	10.92%	11.40%
Spire, Inc.	SR	4.04%	0.76	12.83%	8.79%	10.75%	11.27%
Mean						10.74%	11.26%
Median						10.75%	11.27%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 9, September 1, 2023, at 2
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.75	12.83%	9.03%	10.56%	11.12%
NiSource Inc.	NI	3.80%	0.81	12.83%	9.03%	11.16%	11.58%
Northwest Natural Gas Company	NWN	3.80%	0.70	12.83%	9.03%	10.12%	10.80%
ONE Gas, Inc.	OGS	3.80%	0.78	12.83%	9.03%	10.87%	11.36%
Spire, Inc.	SR	3.80%	0.76	12.83%	9.03%	10.69%	11.23%
Mean						10.68%	11.22%
Median						10.69%	11.23%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.21%	0.74	12.83%	8.62%	10.59%	11.15%
NiSource Inc.	NI	4.21%	0.74	12.83%	8.62%	10.57%	11.13%
Northwest Natural Gas Company	NWN	4.21%	0.70	12.83%	8.62%	10.24%	10.89%
ONE Gas, Inc.	OGS	4.21%	0.73	12.83%	8.62%	10.49%	11.08%
Spire, Inc.	SR	4.21%	0.73	12.83%	8.62%	10.50%	11.08%
Mean						10.48%	11.07%
Median						10.50%	11.08%

Notes:
[1] Source: Bloomberg Professional 30-day average as of August 31, 2023
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.04%	0.74	12.83%	8.79%	10.54%	11.12%
NiSource Inc.	NI	4.04%	0.74	12.83%	8.79%	10.52%	11.10%
Northwest Natural Gas Company	NWN	4.04%	0.70	12.83%	8.79%	10.19%	10.85%
ONE Gas, Inc.	OGS	4.04%	0.73	12.83%	8.79%	10.44%	11.04%
Spire, Inc.	SR	4.04%	0.73	12.83%	8.79%	10.46%	11.05%
Mean						10.43%	11.03%
Median						10.46%	11.05%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 9, September 1, 2023, at 2
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.74	12.83%	9.03%	10.48%	11.07%
NiSource Inc.	NI	3.80%	0.74	12.83%	9.03%	10.46%	11.05%
Northwest Natural Gas Company	NWN	3.80%	0.70	12.83%	9.03%	10.12%	10.80%
ONE Gas, Inc.	OGS	3.80%	0.73	12.83%	9.03%	10.38%	10.99%
Spire, Inc.	SR	3.80%	0.73	12.83%	9.03%	10.39%	11.00%
Mean						10.37%	10.98%
Median						10.39%	11.00%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.74
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.74
Northwest Natural Gas Company	NWN	0.65	0.7	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.70
ONE Gas, Inc.	OGS	NA	NA	NA	0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.73
Spire, Inc.	SR	0.65	0.7	0.7	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.73
Mean		0.74	0.76	0.72	0.69	0.68	0.60	0.61	0.82	0.83	0.82	0.73

Notes:
[1] Value Line, dated December 26, 2013
[2] Value Line, dated December 31, 2014
[3] Value Line, dated December 30, 2015
[4] Value Line, dated December 29, 2016
[5] Value Line, dated December 28, 2017
[6] Value Line, dated December 27, 2018
[7] Value Line, dated December 26, 2019
[8] Value Line, dated December 30, 2020
[9] Value Line, dated December 29, 2021
[10] Value Line, dated December 30, 2022
[11] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.61%
[2] Estimate of the S&P 500 Growth Rate	11.13%
[3] S&P 500 Estimated Required Market Return	12.83%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	324.197	98.77	32,020.94	0.11%	5.06%	0.01%	10.50%	0.01%
American Express Co	AXP	736.459	157.99	116,353.16	0.41%	1.52%	0.01%	11.89%	0.05%
Verizon Communications Inc	VZ	4204.04	34.98	147,057.32		7.46%			
Broadcom Inc	AVGO	412.685	922.89	380,862.86	1.34%	1.99%	0.03%	12.40%	0.17%
Boeing Co/The	BA	603.204	224.03	135,135.79					
Caterpillar Inc	CAT	510.143	281.13	143,416.50	0.51%	1.85%	0.01%	15.00%	0.08%
JPMorgan Chase & Co	JPM	2906.085	146.33	425,247.42		2.73%		-0.50%	
Chevron Corp	CVX	1867.245	161.1	300,813.17	1.06%	3.75%	0.04%	14.77%	0.16%
Coca-Cola Co/The	KO	4324.345	59.83	258,725.56	0.91%	3.08%	0.03%	7.19%	0.07%
AbbVie Inc	ABBV	1765.047	146.96	259,391.31	0.91%	4.03%	0.04%	6.50%	0.06%
Walt Disney Co/The	DIS	1829.779	83.68	153,115.91				22.27%	
FleetCor Technologies Inc	FLT	73.957	271.73	20,096.34	0.07%			12.30%	0.01%
Extra Space Storage Inc	EXR	211.277	128.68	27,187.12	0.10%	1.90%	0.00%	2.46%	0.00%
Exxon Mobil Corp	XOM	4003.193	111.19	445,115.03	1.57%	3.27%	0.05%	13.89%	0.22%
Phillips 66	PSX	445.288	114.16	50,834.08	0.18%	3.68%	0.01%	13.29%	0.02%
General Electric Co	GE	1088.378	114.46	124,575.75	0.44%	0.28%	0.00%	7.00%	0.03%
HP Inc	HPQ	985.956	29.71	29,292.75		3.53%		-5.48%	
Home Depot Inc/The	HD	1000.066	330.3	330,321.80	1.16%	2.53%	0.03%	3.44%	0.04%
Monolithic Power Systems Inc	MPWR	47.778	521.21	24,902.37		0.77%			
International Business Machines Corp	IBM	911.006	146.83	133,763.01	0.47%	4.52%	0.02%	3.35%	0.02%
Johnson & Johnson	JNJ	2401.485	161.68	388,272.09	1.37%	2.94%	0.04%	4.00%	0.05%
McDonald's Corp	MCD	728.763	281.15	204,891.72	0.72%	2.16%	0.02%	10.40%	0.08%
Merck & Co Inc	MRK	2537.521	108.98	276,539.04		2.68%		49.31%	
3M Co	MMM	551.992	106.67	58,880.99	0.21%	5.62%	0.01%	10.00%	0.02%
American Water Works Co Inc	AWK	194.669	138.74	27,008.38	0.10%	2.04%	0.00%	8.00%	0.01%
Bank of America Corp	BAC	7946.372	28.67	227,822.49		3.35%		-5.00%	
Pfizer Inc	PFE	5645.96	35.38	199,754.06		4.64%		-3.70%	
Procter & Gamble Co/The	PG	2356.894	154.34	363,763.02	1.28%	2.44%	0.03%	6.38%	0.08%
AT&T Inc	T	7149	14.79	105,733.71	0.37%	7.51%	0.03%	2.44%	0.01%
Travelers Cos Inc/The	TRV	228.942	161.23	36,912.32	0.13%	2.48%	0.00%	14.92%	0.02%
RTX Corp	RTX	1455.515	86.04	125,232.51	0.44%	2.74%	0.01%	8.88%	0.04%
Analog Devices Inc	ADI	498.314	180.92	90,154.97	0.32%	1.90%	0.01%	6.50%	0.02%
Walmart Inc	WMT	2692.835	162.61	437,881.90	1.54%	1.40%	0.02%	8.00%	0.12%
Cisco Systems Inc	CSCO	4075.058	57.35	233,704.58	0.82%	2.72%	0.02%	7.50%	0.06%
Intel Corp	INTC	4188	35.14	147,166.32	0.52%	1.42%	0.01%	5.65%	0.03%
General Motors Co	GM	1375.905	33.51	46,106.58	0.16%	1.07%	0.00%	0.36%	0.00%
Microsoft Corp	MSFT	7429.764	327.76	2,435,179.45	8.59%	0.83%	0.07%	16.62%	1.43%
Dollar General Corp	DG	219.476	138.5	30,397.43		1.70%		-0.10%	
Cigna Group/The	CI	295.98	276.26	81,767.43	0.29%	1.78%	0.01%	9.80%	0.03%
Kinder Morgan Inc	KMI	2228.165	17.22	38,369.00	0.14%	6.56%	0.01%	2.00%	0.00%
Citigroup Inc	C	1925.702	41.29	79,512.24		5.13%		-8.06%	
American International Group Inc	AIG	711.9	58.52	41,660.39	0.15%	2.46%	0.00%	10.00%	0.01%
Altria Group Inc	MO	1774.61	44.22	78,473.25	0.28%	8.86%	0.02%	6.00%	0.02%
HCA Healthcare Inc	HCA	271.988	277.3	75,422.27	0.27%	0.87%	0.00%	7.58%	0.02%
International Paper Co	IP	345.999	34.92	12,082.29		5.30%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1283	16.99	21,798.17	0.08%	2.83%	0.00%	3.34%	0.00%
Abbott Laboratories	ABT	1735.358	102.9	178,568.34	0.63%	1.98%	0.01%	2.18%	0.01%
Aflac Inc	AFL	594.062	74.57	44,299.20	0.16%	2.25%	0.00%	5.98%	0.01%
Air Products and Chemicals Inc	APD	222.149	295.49	65,642.81	0.23%	2.37%	0.01%	10.27%	0.02%
Royal Caribbean Cruises Ltd	RCL	256.173	98.94	25,345.76				124.32%	
Hess Corp	HES	307.061	154.5	47,440.92		1.13%		-23.46%	
Archer-Daniels-Midland Co	ADM	536.102	79.3	42,512.89		2.27%		-6.10%	
Automatic Data Processing Inc	ADP	411.987	254.61	104,896.01	0.37%	1.96%	0.01%	16.00%	0.06%
Verisk Analytics Inc	VRSK	145.027	242.22	35,128.44	0.12%	0.56%	0.00%	11.58%	0.01%
AutoZone Inc	AZO	18.156	2531.33	45,958.83	0.16%			13.48%	0.02%
Avery Dennison Corp	AVY	80.583	188.38	15,180.23	0.05%	1.72%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.355	126.53	17,253.00				23.17%	
MSCI Inc	MSCI	79.089	543.62	42,994.36	0.15%	1.02%	0.00%	15.26%	0.02%
Ball Corp	BALL	315.059	54.45	17,154.96	0.06%	1.47%	0.00%	10.30%	0.01%
Axon Enterprise Inc	AXON	74.76	212.91	15,917.15					
Ceridian HCM Holding Inc	CDAY	155.613	72.52	11,285.05					
Carrier Global Corp	CARR	837.628	57.45	48,121.73	0.17%	1.29%	0.00%	10.65%	0.02%
Bank of New York Mellon Corp/The	BK	778.782	44.87	34,943.95	0.12%	3.74%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	411.745	85.55	35,224.78		1.59%			
Baxter International Inc	BAX	506.405	40.6	20,560.04	0.07%	2.86%	0.00%	0.66%	0.00%
Becton Dickinson & Co	BDX	290.109	279.45	81,070.96	0.29%	1.30%	0.00%	9.36%	0.03%
Berkshire Hathaway Inc	BRK/B	1308.07	360.2	471,166.81					
Best Buy Co Inc	BBY	218.211	76.45	16,682.23	0.06%	4.81%	0.00%	3.21%	0.00%
Boston Scientific Corp	BSX	1464.223	53.94	78,980.19	0.28%			12.10%	0.03%
Bristol-Myers Squibb Co	BMY	2089.103	61.65	128,793.20	0.45%	3.70%	0.02%	3.10%	0.01%
Brown-Forman Corp	BF/B	310.136	65.9245	20,445.56	0.07%	1.25%	0.00%	7.04%	0.01%
Coterra Energy Inc	CTRA	755.046	28.19	21,284.75		2.84%		23.02%	
Campbell Soup Co	CPB	298.092	41.7	12,430.44	0.04%	3.55%	0.00%	3.06%	0.00%
Hilton Worldwide Holdings Inc	HLT	261.514	148.65	38,874.06	0.14%	0.40%	0.00%	17.14%	0.02%
Carnival Corp	CCL	1116.014	15.82	17,655.34					
Qorvo Inc	QRVO	97.91	107.39	10,514.55	0.04%			2.83%	0.00%
UDR Inc	UDR	329.48	39.9	13,146.25	0.05%	4.21%	0.00%	7.46%	0.00%
Clorox Co/The	CLX	123.826	156.45	19,372.58	0.07%	3.07%	0.00%	17.90%	0.01%
Paycom Software Inc	PAYC	60.467	294.84	17,828.09		0.51%			
CMS Energy Corp	CMS	291.727	56.19	16,392.14		3.47%			
Newell Brands Inc	NWL	414.2	10.58	4,382.24		2.65%			
Colgate-Palmolive Co	CL	826.692	73.47	60,737.06	0.21%	2.61%	0.01%	7.85%	0.02%
EPAM Systems Inc	EPAM	57.961	258.99	15,011.32	0.05%			4.70%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Comerica Inc	CMA	131.777	48.11	6,339.79		5.90%		-6.12%	
Conagra Brands Inc	CAG	477.867	29.88	14,278.67	0.05%	4.69%	0.00%	1.31%	0.00%
Consolidated Edison Inc	ED	344.924	88.96	30,684.44	0.11%	3.64%	0.00%	4.00%	0.00%
Corning Inc	GLW	852.982	32.82	27,994.87	0.10%	3.41%	0.00%	6.58%	0.01%
Cummins Inc	CMI	141.647	230.04	32,584.48		2.92%			
Caesars Entertainment Inc	CZR	215.29	55.26	11,896.93					
Danaher Corp	DHR	738.352	265	195,663.28	0.69%	0.41%	0.00%	1.00%	0.01%
Target Corp	TGT	461.605	126.55	58,416.11	0.21%	3.48%	0.01%	2.51%	0.01%
Deere & Co	DE	288.001	410.94	118,351.13	0.42%	1.31%	0.01%	18.05%	0.08%
Dominion Energy Inc	D	836.773	48.54	40,616.96	0.14%	5.50%	0.01%	0.30%	0.00%
Dover Corp	DOV	139.874	148.3	20,743.31	0.07%	1.38%	0.00%	13.00%	0.01%
Alliant Energy Corp	LNT	252.719	50.17	12,678.91	0.04%	3.61%	0.00%	6.48%	0.00%
Steel Dynamics Inc	STLD	165.644	106.59	17,655.99		1.59%		-16.45%	
Duke Energy Corp	DUK	771	88.8	68,464.80	0.24%	4.62%	0.01%	6.10%	0.01%
Regency Centers Corp	REG	171.003	62.2	10,636.39	0.04%	4.18%	0.00%	5.02%	0.00%
Eaton Corp PLC	ETN	399	230.37	91,917.63	0.32%	1.49%	0.00%	15.00%	0.05%
Ecolab Inc	ECL	285.034	183.81	52,392.10	0.18%	1.15%	0.00%	16.00%	0.03%
Revvity Inc	RVTY	124.135	117.03	14,527.52		0.24%		46.45%	
Emerson Electric Co	EMR	571.5	98.25	56,149.88	0.20%	2.12%	0.00%	11.80%	0.02%
EOG Resources Inc	EOG	582.261	128.62	74,890.41	0.26%	2.57%	0.01%	11.33%	0.03%
Aon PLC	AON	202.867	333.39	67,633.83	0.24%	0.74%	0.00%	9.17%	0.02%
Entergy Corp	ETR	211.456	95.25	20,141.18	0.07%	4.49%	0.00%	6.33%	0.00%
Equifax Inc	EFX	122.72	206.7	25,366.22	0.09%	0.75%	0.00%	11.40%	0.01%
EQT Corp	EQT	411.26	43.22	17,774.66		1.39%		22.19%	
IQVIA Holdings Inc	IQV	183.122	222.63	40,768.45	0.14%			13.16%	0.02%
Gartner Inc	IT	78.825	349.68	27,563.53	0.10%			7.22%	0.01%
FedEx Corp	FDX	251.51	261.02	65,649.14	0.23%	1.93%	0.00%	13.00%	0.03%
FMC Corp	FMC	124.734	86.23	10,755.81	0.04%	2.69%	0.00%	8.00%	0.00%
Brown & Brown Inc	BRO	283.613	74.1	21,015.72	0.07%	0.62%	0.00%	9.00%	0.01%
Ford Motor Co	F	3931.374	12.13	47,687.57	0.17%	4.95%	0.01%	10.96%	0.02%
NextEra Energy Inc	NEE	2023.714	66.8	135,184.10	0.48%	2.80%	0.01%	8.75%	0.04%
Franklin Resources Inc	BEN	498.978	26.74	13,342.67		4.49%		-6.13%	
Garmin Ltd	GRMN	191.452	106.02	20,297.74	0.07%	2.75%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1433.636	39.91	57,216.41		1.50%			
Dexcom Inc	DXCM	387.872	100.98	39,167.31				30.96%	
General Dynamics Corp	GD	273.043	226.64	61,882.47	0.22%	2.33%	0.01%	10.90%	0.02%
General Mills Inc	GIS	581.181	67.66	39,322.71	0.14%	3.49%	0.00%	8.00%	0.01%
Genuine Parts Co	GPC	140.438	153.73	21,589.53	0.08%	2.47%	0.00%	8.95%	0.01%
Atmos Energy Corp	ATO	148.462	115.95	17,214.17	0.06%	2.55%	0.00%	7.50%	0.00%
WW Grainger Inc	GWW	50.001	714.14	35,707.71		1.04%			
Halliburton Co	HAL	898.546	38.62	34,701.85		1.66%		23.40%	
L3Harris Technologies Inc	LHX	189.133	176.95	33,467.08	0.12%	2.58%	0.00%	2.50%	0.00%
Healthpeak Properties Inc	PEAK	547.054	20.58	11,258.37	0.04%	5.83%	0.00%	4.72%	0.00%
Insulet Corp	PODD	69.821	191.71	13,385.38				36.33%	
Catalent Inc	CTLT	180.272	49.97	9,008.19	0.03%			12.00%	0.00%
Fortive Corp	FTV	352.024	78.85	27,757.09	0.10%	0.36%	0.00%	7.93%	0.01%
Hershey Co/The	HSY	149.854	214.86	32,197.63	0.11%	2.22%	0.00%	9.50%	0.01%
Synchrony Financial	SYF	418.183	32.28	13,498.95		3.10%		64.00%	
Hormel Foods Corp	HRL	546.481	38.59	21,088.70	0.07%	2.85%	0.00%	2.50%	0.00%
Arthur J Gallagher & Co	AJG	215.506	230.48	49,669.82	0.18%	0.95%	0.00%	12.19%	0.02%
Mondelez International Inc	MDLZ	1360.418	71.26	96,943.39	0.34%	2.39%	0.01%	8.04%	0.03%
CenterPoint Energy Inc	CNP	629.432	27.89	17,554.86		2.72%			
Humana Inc	HUM	123.907	461.63	57,199.19	0.20%	0.77%	0.00%	12.32%	0.02%
Willis Towers Watson PLC	WTW	104.823	206.76	21,673.20	0.08%	1.63%	0.00%	10.82%	0.01%
Illinois Tool Works Inc	ITW	302.39	247.35	74,796.17	0.26%	2.26%	0.01%	3.94%	0.01%
CDW Corp/DE	CDW	134.048	211.15	28,304.24	0.10%	1.12%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	228.398	205.26	46,880.97	0.17%	1.46%	0.00%	11.68%	0.02%
Interpublic Group of Cos Inc/The	IPG	384.935	32.61	12,552.73	0.04%	3.80%	0.00%	6.99%	0.00%
International Flavors & Fragrances Inc	IFF	255.253	70.45	17,982.57		4.60%		-1.16%	
Generac Holdings Inc	GNRC	62.243	118.81	7,395.09	0.03%			4.50%	0.00%
NXP Semiconductors NV	NXPI	257.802	205.72	53,035.03		1.97%		20.50%	
Kellogg Co	K	342.347	61.02	20,890.01	0.07%	3.93%	0.00%	4.51%	0.00%
Broadridge Financial Solutions Inc	BR	118.117	186.21	21,994.57		1.72%			
Kimberly-Clark Corp	KMB	338.185	128.83	43,568.37	0.15%	3.66%	0.01%	9.71%	0.01%
Kimco Realty Corp	KIM	619.892	18.94	11,740.75	0.04%	4.86%	0.00%	4.65%	0.00%
Oracle Corp	ORCL	2714.259	120.39	326,769.64	1.15%	1.33%	0.02%	15.00%	0.17%
Kroger Co/The	KR	717.746	46.39	33,296.24	0.12%	2.50%	0.00%	4.76%	0.01%
Lennar Corp	LEN	252.526	119.09	30,073.32		1.26%		-3.15%	
Eli Lilly & Co	LLY	949.295	554.2	526,099.29		0.82%		23.35%	
Bath & Body Works Inc	BBWI	228.912	36.87	8,439.99	0.03%	2.17%	0.00%	11.38%	0.00%
Charter Communications Inc	CHTR	149.671	438.12	65,573.86	0.23%			15.90%	0.04%
Lincoln National Corp	LNC	169.638	25.66	4,352.91		7.01%			
Loews Corp	L	225.509	62.09	14,001.85		0.40%			
Lowe's Cos Inc	LOW	577.115	230.48	133,013.47		1.91%		20.64%	
IDEX Corp	IEX	75.602	226.4	17,116.29	0.06%	1.13%	0.00%	10.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.954	194.99	96,316.09	0.34%	1.46%	0.00%	11.25%	0.04%
Masco Corp	MAS	224.926	59.01	13,272.88	0.05%	1.93%	0.00%	6.74%	0.00%
S&P Global Inc	SPGI	318.2	390.86	124,371.65	0.44%	0.92%	0.00%	13.72%	0.06%
Medtronic PLC	MDT	1330.534	81.5	108,438.52	0.38%	3.39%	0.01%	3.17%	0.01%
Viatris Inc	VTRS	1199.532	10.75	12,894.97		4.47%		-2.18%	
CVS Health Corp	CVS	1284.399	65.17	83,704.28	0.30%	3.71%	0.01%	7.13%	0.02%
DuPont de Nemours Inc	DD	459.061	76.89	35,297.20	0.12%	1.87%	0.00%	12.85%	0.02%
Micron Technology Inc	MU	1095.302	69.94	76,605.42		0.66%		-15.93%	
Motorola Solutions Inc	MSI	167.02	283.57	47,361.86		1.24%			
Cboe Global Markets Inc	CBOE	105.517	149.71	15,796.95		1.47%			
Laboratory Corp of America Holdings	LH	88.6	208.1	18,437.66		1.38%		-4.73%	
Newmont Corp	NEM	794.732	39.42	31,328.34	0.11%	4.06%	0.00%	11.86%	0.01%
NIKE Inc	NKE	1225.074	101.37	124,185.75	0.44%	1.34%	0.01%	15.34%	0.07%
NiSource Inc	NI	413.255	26.76	11,058.70	0.04%	3.74%	0.00%	7.50%	0.00%
Norfolk Southern Corp	NSC	227.015	205.01	46,540.35	0.16%	2.63%	0.00%	4.34%	0.01%
Principal Financial Group Inc	PFG	241.715	77.71	18,783.67	0.07%	3.35%	0.00%	7.38%	0.00%
Eversource Energy	ES	349.086	63.82	22,278.67	0.08%	4.23%	0.00%	4.99%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Northrop Grumman Corp	NOC	151.3	433.09	65,526.52	0.23%	1.73%	0.00%	4.06%	0.01%
Wells Fargo & Co	WFC	3667.7	41.29	151,439.33	0.53%	3.39%	0.02%	13.41%	0.07%
Nucor Corp	NUE	248.722	172.1	42,805.06		1.19%		-10.89%	
Occidental Petroleum Corp	OXY	884.682	62.79	55,549.18		1.15%		-13.74%	
Omnicom Group Inc	OMC	197.571	81.01	16,005.23	0.06%	3.46%	0.00%	6.31%	0.00%
ONEOK Inc	OKE	447.675	65.2	29,188.41	0.10%	5.86%	0.01%	7.08%	0.01%
Raymond James Financial Inc	RJF	208.842	104.59	21,842.78		1.61%			
PG&E Corp	PCG	2091.241	16.3	34,087.23	0.12%			8.50%	0.01%
Parker-Hannifin Corp	PH	128.431	416.9	53,542.88	0.19%	1.42%	0.00%	14.56%	0.03%
Rollins Inc	ROL	492.821	39.57	19,500.93	0.07%	1.31%	0.00%	13.72%	0.01%
PPL Corp	PPL	737.089	24.92	18,368.26	0.06%	3.85%	0.00%	7.21%	0.00%
ConocoPhillips	COP	1197.491	119.03	142,537.35		0.50%		-0.50%	
PulteGroup Inc	PHM	219.445	82.06	18,007.66		0.78%		-3.91%	
Pinnacle West Capital Corp	PNW	113.312	77.27	8,755.62	0.03%	4.48%	0.00%	6.46%	0.00%
PNC Financial Services Group Inc/The	PNC	398.255	120.73	48,081.33		5.14%		-0.12%	
PPG Industries Inc	PPG	235.513	141.76	33,386.32	0.12%	1.83%	0.00%	11.30%	0.01%
Progressive Corp/The	PGR	585.1	133.47	78,093.30		0.30%		38.38%	
Public Service Enterprise Group Inc	PEG	499.111	61.08	30,485.70	0.11%	3.73%	0.00%	6.73%	0.01%
Robert Half Inc	RHI	107.082	73.96	7,919.78	0.03%	2.60%	0.00%	0.78%	0.00%
Edison International	EIX	383.289	68.85	26,389.45	0.09%	4.28%	0.00%	5.35%	0.00%
Schlumberger NV	SLB	1421.186	58.96	83,793.13		1.70%		27.56%	
Charles Schwab Corp/The	SCHW	1770.22	59.15	104,708.51	0.37%	1.69%	0.01%	5.31%	0.02%
Sherwin-Williams Co/The	SHW	257.149	271.72	69,872.53	0.25%	0.89%	0.00%	8.49%	0.02%
West Pharmaceutical Services Inc	WST	73.861	406.9	30,054.04	0.11%	0.19%	0.00%	18.65%	0.02%
J M Smucker Co/The	SJM	102.131	144.95	14,803.89	0.05%	2.93%	0.00%	6.09%	0.00%
Snap-on Inc	SNA	52.917	268.6	14,213.51	0.05%	2.41%	0.00%	4.87%	0.00%
AMETEK Inc	AME	230.712	159.51	36,800.87	0.13%	0.63%	0.00%	9.74%	0.01%
Southern Co/The	SO	1091.515	67.73	73,928.31	0.26%	4.13%	0.01%	4.50%	0.01%
Truist Financial Corp	TFC	1331.976	30.55	40,691.87	0.14%	6.81%	0.01%	4.13%	0.01%
Southwest Airlines Co	LUV	595.634	31.6	18,822.03		2.28%		29.08%	
W R Berkley Corp	WRB	257.523	61.86	15,930.37	0.06%	0.71%	0.00%	12.50%	0.01%
Stanley Black & Decker Inc	SWK	153.23	93.57	14,337.73		3.46%			
Public Storage	PSA	175.829	276.38	48,595.62	0.17%	4.34%	0.01%	3.73%	0.01%
Arista Networks Inc	ANET	309.581	195.23	60,439.50	0.21%			19.35%	0.04%
Sysco Corp	SYY	504.926	69.65	35,168.10		2.87%			
Corteva Inc	CTVA	709.516	50.51	35,837.65	0.13%	1.27%	0.00%	17.92%	0.02%
Texas Instruments Inc	TXN	907.966	168.06	152,592.77	0.54%	2.95%	0.02%	7.80%	0.04%
Textron Inc	TXT	198.071	77.71	15,392.10	0.05%	0.10%	0.00%	11.73%	0.01%
Thermo Fisher Scientific Inc	TMO	385.95	557.1	215,012.75		0.25%			
TJX Cos Inc/The	TJX	1144.081	92.48	105,804.61	0.37%	1.44%	0.01%	10.00%	0.04%
Globe Life Inc	GL	94.82	111.57	10,579.07		0.81%			
Johnson Controls International plc	JCI	680.32	59.06	40,179.70	0.14%	2.51%	0.00%	15.62%	0.02%
Ulta Beauty Inc	ULTA	49.229	415.03	20,431.51	0.07%			6.54%	0.00%
Union Pacific Corp	UNP	609.456	220.57	134,427.71	0.47%	2.36%	0.01%	6.50%	0.03%
Keysight Technologies Inc	KEYS	177.575	133.3	23,670.75	0.08%			2.52%	0.00%
UnitedHealth Group Inc	UNH	926.305	476.58	441,458.44	1.56%	1.58%	0.02%	11.90%	0.19%
Marathon Oil Corp	MRO	605.687	26.35	15,959.85		1.52%		-10.70%	
Bio-Rad Laboratories Inc	BIO	24.004	400.2	9,606.40	0.03%			6.00%	0.00%
Ventas Inc	VTR	402.378	43.68	17,575.87	0.06%	4.12%	0.00%	8.12%	0.01%
VF Corp	VFC	388.868	19.76	7,684.03	0.03%	6.07%	0.00%	11.54%	0.00%
Vulcan Materials Co	VMC	132.866	218.25	28,998.00		0.79%		21.48%	
Weyerhaeuser Co	WY	730.748	32.75	23,932.00		2.32%			
Whirlpool Corp	WHR	54.818	139.96	7,672.33		5.00%		-1.35%	
Williams Cos Inc/The	WMB	1216.421	34.53	42,003.02	0.15%	5.18%	0.01%	3.50%	0.01%
Constellation Energy Corp	CEG	321.592	104.16	33,497.02		1.08%		23.30%	
WEC Energy Group Inc	WEC	315.435	84.12	26,534.39	0.09%	3.71%	0.00%	6.26%	0.01%
Adobe Inc	ADBE	455.8	559.34	254,947.17	0.90%			16.90%	0.15%
AES Corp/The	AES	669.629	17.93	12,006.45	0.04%	3.70%	0.00%	9.12%	0.00%
Amgen Inc	AMGN	534.901	256.34	137,116.52		3.32%			
Apple Inc	AAPL	15634.232	187.87	2,937,203.17	10.36%	0.51%	0.05%	11.00%	1.14%
Autodesk Inc	ADSK	213.764	221.94	47,442.78	0.17%			13.86%	0.02%
Cintas Corp	CTAS	101.742	504.17	51,295.26	0.18%	1.07%	0.00%	9.74%	0.02%
Comcast Corp	CMCSA	4115.689	46.76	192,449.62	0.68%	2.48%	0.02%	8.68%	0.06%
Molson Coors Beverage Co	TAP	200.96	63.49	12,758.95	0.04%	2.58%	0.00%	7.07%	0.00%
KLA Corp	KLAC	136.72	501.87	68,615.67	0.24%	1.04%	0.00%	9.27%	0.02%
Marriott International Inc/MD	MAR	298.24	203.51	60,694.82	0.21%	1.02%	0.00%	17.05%	0.04%
Fiserv Inc	FI	609.615	121.39	74,001.16	0.26%			14.63%	0.04%
McCormick & Co Inc/MD	MKC	251.1	82.08	20,610.29	0.07%	1.90%	0.00%	7.01%	0.01%
PACCAR Inc	PCAR	522.805	82.29	43,021.62	0.15%	1.31%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	443.148	549.28	243,412.33	0.86%	0.74%	0.01%	12.46%	0.11%
Stryker Corp	SYK	379.778	283.55	107,686.05	0.38%	1.06%	0.00%	7.07%	0.03%
Tyson Foods Inc	TSN	285.55	53.27	15,211.25		3.60%		-22.91%	
Lamb Weston Holdings Inc	LW	145.667	97.41	14,189.42	0.05%	1.15%	0.00%	12.14%	0.01%
Applied Materials Inc	AMAT	836.534	152.76	127,788.93	0.45%	0.84%	0.00%	3.73%	0.02%
American Airlines Group Inc	AAL	653.362	14.73	9,624.02				80.75%	
Cardinal Health Inc	CAH	250.682	87.33	21,892.06		2.29%			
Cincinnati Financial Corp	CINF	156.856	105.79	16,593.80	0.06%	2.84%	0.00%	17.66%	0.01%
Paramount Global	PARA	610.399	15.09	9,210.92	0.03%	1.33%	0.00%	5.71%	0.00%
DR Horton Inc	DHI	338.297	119.02	40,264.11		0.84%		-8.43%	
Electronic Arts Inc	EA	270.912	119.98	32,504.02	0.11%	0.63%	0.00%	5.64%	0.01%
Fair Isaac Corp	FICO	24.857	904.59	22,485.39					
Expeditors International of Washington Inc	EXPD	147.897	116.71	17,261.06		1.18%			
Fastenal Co	FAST	571.333	57.58	32,897.35		2.43%			
M&T Bank Corp	MTB	165.949	125.05	20,751.92	0.07%	4.16%	0.00%	11.10%	0.01%
Xcel Energy Inc	XEL	551.533	57.13	31,509.08	0.11%	3.64%	0.00%	6.14%	0.01%
Fifth Third Bancorp	FITB	680.889	26.55	18,077.60		4.97%		25.00%	
Gilead Sciences Inc	GILD	1246.014	76.48	95,295.15	0.34%	3.92%	0.01%	0.73%	0.00%
Hasbro Inc	HAS	138.741	72	9,989.35	0.04%	3.89%	0.00%	8.64%	0.00%
Huntington Bancshares Inc/OH	HBAN	1447.882	11.09	16,057.01		5.59%		-5.65%	
Welltower Inc	WELL	518.729	82.88	42,992.26	0.15%	2.94%	0.00%	10.72%	0.02%
Biogen Inc	BIIB	144.823	267.36	38,719.88	0.14%			0.06%	0.00%
Northern Trust Corp	NTRS	207.004	76.07	15,746.79	0.06%	3.94%	0.00%	13.00%	0.01%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Packaging Corp of America	PKG	89.915	149.1	13,406.33	0.05%	3.35%	0.00%	3.00%	0.00%
Paychex Inc	PAYX	360.546	122.23	44,069.54	0.16%	2.91%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1116	114.53	127,815.48		2.79%			
Ross Stores Inc	ROST	340.656	121.475	41,381.19	0.15%	1.10%	0.00%	10.00%	0.01%
IDEXX Laboratories Inc	IDXX	83.012	511.41	42,453.17	0.15%			17.57%	0.03%
Starbucks Corp	SBUX	1145.4	97.44	111,607.78	0.39%	2.18%	0.01%	19.71%	0.08%
KeyCorp	KEY	935.919	11.33	10,603.96	0.04%	7.24%	0.00%	7.53%	0.00%
Fox Corp	FOXA	253.684	33.06	8,386.79	0.03%	1.57%	0.00%	12.00%	0.00%
Fox Corp	FOX	235.581	30.52	7,189.93	0.03%	1.70%	0.00%	12.00%	0.00%
State Street Corp	STT	318.64	68.74	21,903.31	0.08%	4.02%	0.00%	1.31%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	425.424	16.57	7,049.28					
US Bancorp	USB	1556.965	36.53	56,875.93	0.20%	5.26%	0.01%	8.00%	0.02%
A O Smith Corp	AOS	124.59	72.5	9,032.78		1.66%			
Gen Digital Inc	GEN	639.439	20.25	12,948.64		2.47%			
T Rowe Price Group Inc	TROW	224.295	112.23	25,172.63		4.35%		-3.36%	
Waste Management Inc	WM	405.059	156.78	63,505.15	0.22%	1.79%	0.00%	9.80%	0.02%
Constellation Brands Inc	STZ	183.301	260.56	47,760.91	0.17%	1.37%	0.00%	9.73%	0.02%
DENTSPLY SIRONA Inc	XRAY	211.716	37.09	7,852.55	0.03%	1.51%	0.00%	9.78%	0.00%
Zions Bancorp NA	ZION	148.145	35.5	5,259.15		4.62%		-3.00%	
Alaska Air Group Inc	ALK	127.224	41.97	5,339.59				23.98%	
Invesco Ltd	IVZ	448.621	15.92	7,142.05	0.03%	5.03%	0.00%	4.26%	0.00%
Intuit Inc	INTU	280.06	541.81	151,739.31	0.53%	0.66%	0.00%	18.84%	0.10%
Morgan Stanley	MS	1656.967	85.15	141,090.74	0.50%	3.99%	0.02%	3.76%	0.02%
Microchip Technology Inc	MCHP	544.334	81.84	44,548.29	0.16%	2.00%	0.00%	12.06%	0.02%
Chubb Ltd	CB	410.735	200.87	82,504.34	0.29%	1.71%	0.00%	14.50%	0.04%
Hologic Inc	HOLX	244.942	74.74	18,306.97				-14.09%	
Citizens Financial Group Inc	CFG	472.294	28.13	13,285.63		5.97%		-6.14%	
O'Reilly Automotive Inc	ORLY	60.258	939.7	56,624.44	0.20%			12.13%	0.02%
Allstate Corp/The	ALL	261.574	107.81	28,200.29		3.30%		-4.00%	
Equity Residential	EQR	379.032	64.83	24,572.64	0.09%	4.09%	0.00%	5.68%	0.00%
BorgWarner Inc	BWA	235.063	40.75	9,578.82	0.03%	1.08%	0.00%	5.31%	0.00%
Keurig Dr Pepper Inc	KDP	1397.259	33.65	47,017.77	0.17%	2.38%	0.00%	6.35%	0.01%
Organon & Co	OGN	255.568	21.96	5,612.27	0.02%	5.10%	0.00%	7.34%	0.00%
Host Hotels & Resorts Inc	HST	711.605	15.79	11,236.24		3.80%			
Incyte Corp	INCY	224.088	64.53	14,460.40				65.18%	
Simon Property Group Inc	SPG	327.191	113.49	37,132.91	0.13%	6.70%	0.01%	2.04%	0.00%
Eastman Chemical Co	EMN	118.556	85.01	10,078.45	0.04%	3.72%	0.00%	5.93%	0.00%
AvalonBay Communities Inc	AVB	142.016	183.82	26,105.38	0.09%	3.59%	0.00%	10.28%	0.01%
Prudential Financial Inc	PRU	363	94.67	34,365.21	0.12%	5.28%	0.01%	10.60%	0.01%
United Parcel Service Inc	UPS	723.276	169.4	122,522.95		3.83%		-3.89%	
Walgreens Boots Alliance Inc	WBA	863.261	25.31	21,849.14		7.59%		-6.57%	
STERIS PLC	STE	98.781	229.59	22,679.13		0.91%			
McKesson Corp	MCK	134.902	412.32	55,622.79	0.20%	0.60%	0.00%	10.03%	0.02%
Lockheed Martin Corp	LMT	251.831	448.35	112,908.43	0.40%	2.68%	0.01%	6.98%	0.03%
Cencora Inc	COR	202.175	175.98	35,578.76	0.13%	1.10%	0.00%	9.44%	0.01%
Capital One Financial Corp	COF	381.441	102.39	39,055.74		2.34%		-2.93%	
Waters Corp	WAT	59.103	280.8	16,596.12	0.06%			5.79%	0.00%
Nordson Corp	NDSN	57.014	244.14	13,919.40		1.11%			
Dollar Tree Inc	DLTR	220.006	122.36	26,919.93	0.09%			7.37%	0.01%
Darden Restaurants Inc	DRI	120.873	155.51	18,796.96	0.07%	3.37%	0.00%	10.79%	0.01%
Evergy Inc	EVRG	229.583	54.97	12,620.18	0.04%	4.46%	0.00%	4.74%	0.00%
Match Group Inc	MTCH	278.087	46.87	13,033.94				62.00%	
Domino's Pizza Inc	DPZ	35.094	387.4	13,595.42	0.05%	1.25%	0.00%	13.94%	0.01%
NVR Inc	NVR	3.264	6377.33	20,815.61				-3.60%	
NetApp Inc	NTAP	208.791	76.7	16,014.27	0.06%	2.61%	0.00%	7.40%	0.00%
DXC Technology Co	DXC	205.174	20.74	4,255.31	0.02%			6.84%	0.00%
Old Dominion Freight Line Inc	ODFL	109.268	427.37	46,697.87	0.16%	0.37%	0.00%	4.45%	0.01%
DaVita Inc	DVA	91.3	102.42	9,350.95	0.03%			15.78%	0.01%
Hartford Financial Services Group Inc/The	HIG	305.817	71.82	21,963.78	0.08%	2.37%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.852	63.54	18,544.28	0.07%	4.09%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	232.149	160.53	37,266.88	0.13%	1.64%	0.00%	8.40%	0.01%
Cadence Design Systems Inc	CDNS	271.79	240.44	65,349.19	0.23%			19.00%	0.04%
Tyler Technologies Inc	TYL	42.078	398.43	16,765.14					
Universal Health Services Inc	UHS	62.14	134.7	8,370.26	0.03%	0.59%	0.00%	11.82%	0.00%
Skyworks Solutions Inc	SWKS	159.393	108.74	17,332.39	0.06%	2.50%	0.00%	4.99%	0.00%
Quest Diagnostics Inc	DGX	112.235	131.5	14,758.90		2.16%		-0.67%	
Activision Blizzard Inc	ATVI	786.798	91.99	72,377.55	0.26%	1.08%	0.00%	7.00%	0.02%
Rockwell Automation Inc	ROK	114.86	312.08	35,845.51	0.13%	1.51%	0.00%	15.59%	0.02%
Kraft Heinz Co/The	KHC	1228.295	33.09	40,644.28	0.14%	4.84%	0.01%	3.92%	0.01%
American Tower Corp	AMT	466.156	181.32	84,523.41	0.30%	3.46%	0.01%	13.29%	0.04%
Regeneron Pharmaceuticals Inc	REGN	106.741	826.49	88,220.37	0.31%			1.00%	0.00%
Amazon.com Inc	AMZN	10317.751	138.01	1,423,952.82				51.21%	
Jack Henry & Associates Inc	JKHY	72.935	156.78	11,434.75	0.04%	1.33%	0.00%	7.41%	0.00%
Ralph Lauren Corp	RL	40.388	116.63	4,710.45	0.02%	2.57%	0.00%	10.73%	0.00%
Boston Properties Inc	BXP	156.865	66.77	10,473.88	0.04%	5.87%	0.00%	3.79%	0.00%
Amphenol Corp	APH	596.454	88.38	52,714.60	0.19%	0.95%	0.00%	5.46%	0.01%
Howmet Aerospace Inc	HWM	412.208	49.47	20,391.93	0.07%	0.32%	0.00%	19.27%	0.01%
Pioneer Natural Resources Co	PXD	233.141	237.93	55,471.24		3.09%		-0.73%	
Valero Energy Corp	VLO	353.133	129.9	45,871.98		3.14%		-7.69%	
Synopsys Inc	SNPS	152.084	458.89	69,789.83	0.25%			16.27%	0.04%
Etsy Inc	ETSY	123.014	73.57	9,050.14	0.03%			8.15%	0.00%
CH Robinson Worldwide Inc	CHRW	116.439	90.43	10,529.58	0.04%	2.70%	0.00%	5.00%	0.00%
Accenture PLC	ACN	630.795	323.77	204,232.50	0.72%	1.38%	0.01%	10.00%	0.07%
TransDigm Group Inc	TDG	55.183	903.85	49,877.15				26.65%	
Yum! Brands Inc	YUM	280.211	129.38	36,253.70	0.13%	1.87%	0.00%	11.45%	0.01%
Prologis Inc	PLD	923.862	124.2	114,743.66	0.40%	2.80%	0.01%	8.95%	0.04%
FirstEnergy Corp	FE	573.362	36.07	20,681.17		4.32%		-6.66%	
VeriSign Inc	VRSN	103.134	207.79	21,430.21	0.08%			12.30%	0.01%
Quanta Services Inc	PWR	145.199	209.87	30,472.91	0.11%	0.15%	0.00%	8.00%	0.01%
Henry Schein Inc	HSIC	130.585	76.54	9,994.98	0.04%			5.16%	0.00%
Ameren Corp	AEE	262.475	79.27	20,806.39	0.07%	3.18%	0.00%	6.93%	0.01%
ANSYS Inc	ANSS	86.791	318.87	27,675.05	0.10%			11.14%	0.01%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
FactSet Research Systems Inc	FDS	38.146	436.41	16,647.30	0.06%	0.90%	0.00%	11.97%	0.01%
NVIDIA Corp	NVDA	2470	493.55	1,219,068.50		0.03%		56.84%	
Sealed Air Corp	SEE	144.41	37.06	5,351.83	0.02%	2.16%	0.00%	0.93%	0.00%
Cognizant Technology Solutions Corp	CTSH	505.041	71.61	36,165.99	0.13%	1.62%	0.00%	12.00%	0.02%
Intuitive Surgical Inc	ISRG	351.355	312.68	109,861.68	0.39%			16.14%	0.06%
Take-Two Interactive Software Inc	TTWO	169.831	142.2	24,149.97				53.59%	
Republic Services Inc	RSG	316.326	144.13	45,592.07	0.16%	1.48%	0.00%	9.26%	0.01%
eBay Inc	EBAY	532.157	44.78	23,829.99	0.08%	2.23%	0.00%	6.50%	0.01%
Goldman Sachs Group Inc/The	GS	329.671	327.71	108,036.48	0.38%	3.36%	0.01%	9.00%	0.03%
SBA Communications Corp	SBAC	108.383	224.53	24,335.23		1.51%			
Sempra	SRE	629.307	70.22	44,189.94	0.16%	3.39%	0.01%	3.45%	0.01%
Moody's Corp	MCO	183.5	336.8	61,802.80	0.22%	0.91%	0.00%	13.87%	0.03%
ON Semiconductor Corp	ON	431.529	98.46	42,488.35	0.15%			8.50%	0.01%
Booking Holdings Inc	BKNG	35.692	3105.03	110,824.73	0.39%			20.00%	0.08%
F5 Inc	FFIV	59.306	163.66	9,706.02	0.03%			10.19%	0.00%
Akamai Technologies Inc	AKAM	151.713	105.09	15,943.52	0.06%			10.00%	0.01%
Charles River Laboratories International Inc	CRL	51.271	206.82	10,603.87	0.04%			14.00%	0.01%
MarketAxess Holdings Inc	MKTX	37.677	240.93	9,077.52		1.20%			
Devon Energy Corp	DVN	640.7	51.09	32,733.36		3.84%		-4.00%	
Bio-Techne Corp	TECH	158.174	78.4	12,400.84		0.41%			
Alphabet Inc	GOOGL	5933	136.17	807,896.61	2.85%			18.01%	0.51%
Teleflex Inc	TFX	46.992	212.74	9,997.08	0.04%	0.64%	0.00%	7.03%	0.00%
Bunge Ltd	BG	150.642	114.32	17,221.39		2.32%		-5.14%	
Allegion plc	ALLE	87.78	113.81	9,990.24	0.04%	1.58%	0.00%	5.43%	0.00%
Netflix Inc	NFLX	443.147	433.68	192,183.99				32.28%	
Agilent Technologies Inc	A	292.587	121.07	35,423.51	0.12%	0.74%	0.00%	11.00%	0.01%
Warner Bros Discovery Inc	WBD	2437.384	13.14	32,027.23					
Elevance Health Inc	ELV	235.648	442.01	104,158.77	0.37%	1.34%	0.00%	12.13%	0.04%
Trimble Inc	TRMB	248.322	54.79	13,605.56					
CME Group Inc	CME	359.746	202.68	72,913.32	0.26%	2.17%	0.01%	6.14%	0.02%
Juniper Networks Inc	JNPR	321.36	29.12	9,358.00	0.03%	3.02%	0.00%	7.89%	0.00%
BlackRock Inc	BLK	149.303	700.54	104,592.72	0.37%	2.85%	0.01%	9.20%	0.03%
DTE Energy Co	DTE	206.109	103.38	21,307.55		3.69%			
Nasdaq Inc	NDAQ	491.316	52.48	25,784.26	0.09%	1.68%	0.00%	2.68%	0.00%
Celanese Corp	CE	108.852	126.36	13,754.54	0.05%	2.22%	0.00%	3.07%	0.00%
Philip Morris International Inc	PM	1552.345	96.06	149,118.26	0.53%	5.29%	0.03%	7.99%	0.04%
Salesforce Inc	CRM	973	221.46	215,480.58				21.67%	
Ingersoll Rand Inc	IR	404.399	69.61	28,150.21		0.11%			
Roper Technologies Inc	ROP	106.711	499.06	53,255.19		0.55%			
Huntington Ingalls Industries Inc	HII	39.868	220.32	8,783.72		2.25%		40.00%	
MetLife Inc	MET	752.022	63.34	47,633.07	0.17%	3.28%	0.01%	13.07%	0.02%
Tapestry Inc	TPR	227.439	33.32	7,578.27	0.03%	4.20%	0.00%	14.00%	0.00%
CSX Corp	CSX	2006.33	30.2	60,591.17	0.21%	1.46%	0.00%	3.11%	0.01%
Edwards Lifesciences Corp	EW	607.916	76.47	46,487.34	0.16%			10.65%	0.02%
Ameriprise Financial Inc	AMP	102.626	337.58	34,644.49	0.12%	1.60%	0.00%	17.59%	0.02%
Zebra Technologies Corp	ZBRA	51.338	275.01	14,118.46					
Zimmer Biomet Holdings Inc	ZBH	208.964	119.12	24,891.79	0.09%	0.81%	0.00%	9.48%	0.01%
CBRE Group Inc	CBRE	309.838	85.05	26,351.72					
Camden Property Trust	CPT	106.771	107.62	11,490.70	0.04%	3.72%	0.00%	7.34%	0.00%
Mastercard Inc	MA	934.848	412.64	385,755.68	1.36%	0.55%	0.01%	18.18%	0.25%
CarMax Inc	KMX	158.21	81.68	12,922.59	0.05%			15.54%	0.01%
Intercontinental Exchange Inc	ICE	560.301	117.99	66,109.91	0.23%	1.42%	0.00%	9.87%	0.02%
Fidelity National Information Services Inc	FIS	592.465	55.86	33,095.09	0.12%	3.72%	0.00%	2.68%	0.00%
Chipotle Mexican Grill Inc	CMG	27.588	1926.64	53,152.14				26.95%	
Wynn Resorts Ltd	WYNN	113.936	101.38	11,550.83		0.99%			
Live Nation Entertainment Inc	LYV	230.151	84.53	19,454.66					
Assurant Inc	AIZ	53.023	139.33	7,387.69	0.03%	2.01%	0.00%	13.68%	0.00%
NRG Energy Inc	NRG	229.117	37.55	8,603.34	0.03%	4.02%	0.00%	4.03%	0.00%
Regions Financial Corp	RF	938.377	18.34	17,209.83	0.06%	5.23%	0.00%	2.08%	0.00%
Monster Beverage Corp	MNST	1047.518	57.41	60,138.01	0.21%			15.05%	0.03%
Mosaic Co/The	MOS	332.28	38.85	12,909.08		2.06%		38.00%	
Baker Hughes Co	BKR	1009.654	36.19	36,539.38		2.21%		57.62%	
Expedia Group Inc	EXPE	137.841	108.39	14,940.59	0.05%			17.50%	0.01%
CF Industries Holdings Inc	CF	192.948	77.07	14,870.50		2.08%		44.50%	
Leidos Holdings Inc	LDOS	137.351	97.51	13,393.10	0.05%	1.48%	0.00%	6.45%	0.00%
APA Corp	APA	307.265	43.84	13,470.50		2.28%		-4.03%	
Alphabet Inc	GOOG	5801	137.35	796,767.35	2.81%			18.01%	0.51%
First Solar Inc	FSLR	106.831	189.12	20,203.88	0.07%			19.80%	0.01%
TE Connectivity Ltd	TEL	313.939	132.39	41,562.38	0.15%	1.78%	0.00%	3.10%	0.00%
Cooper Cos Inc/The	COO	49.524	369.99	18,323.38	0.06%	0.02%	0.00%	7.00%	0.00%
Discover Financial Services	DFS	249.948	90.07	22,512.82	0.08%	3.11%	0.00%	6.93%	0.01%
Linde PLC	LIN	487.946	385.7651	188,232.54	0.66%	1.32%	0.01%	9.20%	0.06%
Visa Inc	V	1606.788	245.68	394,755.68	1.39%	0.73%	0.01%	14.91%	0.21%
Mid-America Apartment Communities Inc	MAA	116.677	145.23	16,945.00		3.86%			
Xylem Inc/NY	XYL	240.829	103.54	24,935.43		1.27%			
Marathon Petroleum Corp	MPC	399.844	142.77	57,085.73		2.10%		32.45%	
Tractor Supply Co	TSCO	108.808	218.5	23,774.55	0.08%	1.89%	0.00%	10.00%	0.01%
Advanced Micro Devices Inc	AMD	1615.671	105.72	170,808.74				26.26%	
ResMed Inc	RMD	147.071	159.59	23,471.06	0.08%	1.20%	0.00%	9.21%	0.01%
Mettler-Toledo International Inc	MTD	21.865	1213.48	26,532.74	0.09%			9.75%	0.01%
Jacobs Solutions Inc	J	125.918	134.82	16,976.26	0.06%	0.77%	0.00%	9.26%	0.01%
Copart Inc	CPRT	954.88	44.83	42,807.27	0.15%			10.00%	0.02%
VICI Properties Inc	VICI	1013.428	30.84	31,254.12	0.11%	5.06%	0.01%	6.33%	0.01%
Albemarle Corp	ALB	117.347	198.71	23,318.02		0.81%		31.93%	
Fortinet Inc	FTNT	785.337	60.21	47,285.14	0.17%			18.00%	0.03%
Moderna Inc	MRNA	380.593	113.07	43,033.65				-60.35%	
Essex Property Trust Inc	ESS	64.183	238.39	15,300.59	0.05%	3.88%	0.00%	9.80%	0.01%
CoStar Group Inc	CSGP	408.337	81.99	33,479.55	0.12%			20.00%	0.02%
Realty Income Corp	O	708.788	56.04	39,720.48		5.47%			
Westrock Co	WRK	256.279	32.71	8,382.89		3.36%		-6.74%	
Westinghouse Air Brake Technologies Corp	WAB	179.13	112.52	20,155.71	0.07%	0.60%	0.00%	11.33%	0.01%
Pool Corp	POOL	39.052	365.6	14,277.41		1.20%		-4.92%	

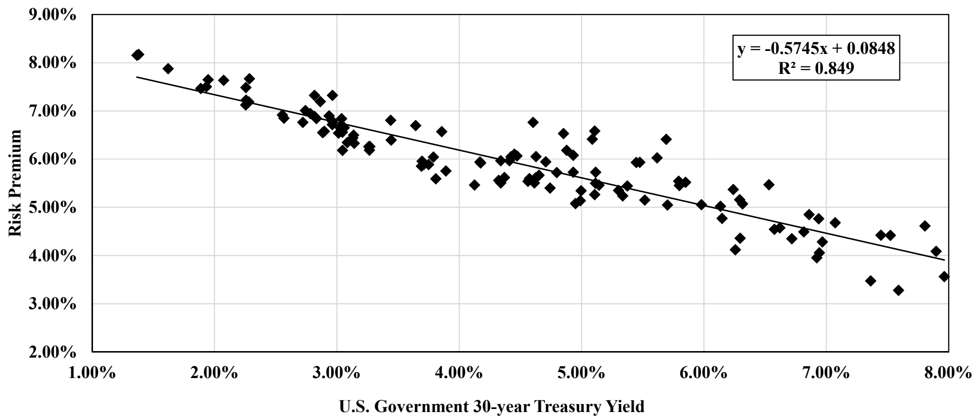
		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Western Digital Corp	WDC	321.896	45	14,485.32				-22.46%	
PepsiCo Inc	PEP	1376.581	177.92	244,921.29	0.86%	2.84%	0.02%	8.64%	0.07%
Diamondback Energy Inc	FANG	178.818	151.78	27,141.00	0.10%	2.21%	0.00%	8.97%	0.01%
Palo Alto Networks Inc	PANW	305.855	243.3	74,414.52				20.50%	
ServiceNow Inc	NOW	204	588.83	120,121.32				30.00%	
Church & Dwight Co Inc	CHD	246.047	96.77	23,809.97	0.08%	1.13%	0.00%	5.85%	0.00%
Federal Realty Investment Trust	FRT	81.523	97.94	7,984.36	0.03%	4.45%	0.00%	6.85%	0.00%
MGM Resorts International	MGM	350.889	43.98	15,432.10					
American Electric Power Co Inc	AEP	515.176	78.4	40,389.80		4.23%			
SolarEdge Technologies Inc	SEDG	56.558	162.57	9,194.63				26.90%	
Invitation Homes Inc	INVH	611.956	34.09	20,861.58	0.07%	3.05%	0.00%	7.96%	0.01%
PTC Inc	PTC	118.833	147.17	17,488.65	0.06%			16.99%	0.01%
JB Hunt Transport Services Inc	JBHT	103.345	187.88	19,416.46	0.07%	0.89%	0.00%	15.00%	0.01%
Lam Research Corp	LRCX	132.512	702.4	93,076.43	0.33%	1.14%	0.00%	12.20%	0.04%
Mohawk Industries Inc	MHK	63.682	101.39	6,456.72				-1.83%	
GE HealthCare Technologies Inc	GEHC	454.838	70.45	32,043.34	0.11%	0.17%	0.00%	12.75%	0.01%
Pentair PLC	PNR	165.113	70.26	11,600.84	0.04%	1.25%	0.00%	6.14%	0.00%
Vertex Pharmaceuticals Inc	VRTX	258.095	348.34	89,904.81	0.32%			13.72%	0.04%
Amcor PLC	AMCR	1448.494	9.74	14,108.33	0.05%	5.03%	0.00%	2.20%	0.00%
Meta Platforms Inc	META	2222.583	295.89	657,640.08				27.44%	
T-Mobile US Inc	TMUS	1176.457	136.25	160,292.27	0.57%			5.00%	0.03%
United Rentals Inc	URI	68.283	476.54	32,539.58		1.24%		20.04%	
Honeywell International Inc	HON	663.961	187.94	124,784.83	0.44%	2.19%	0.01%	9.50%	0.04%
Alexandria Real Estate Equities Inc	ARE	173.028	116.34	20,130.08	0.07%	4.26%	0.00%	4.05%	0.00%
Delta Air Lines Inc	DAL	643.418	42.88	27,589.76		0.93%		37.89%	
Seagate Technology Holdings PLC	STX	207.393	70.79	14,681.35	0.05%	3.96%	0.00%	1.21%	0.00%
United Airlines Holdings Inc	UAL	326.729	49.81	16,274.37					
News Corp	NWS	191.837	22	4,220.41	0.01%	0.91%	0.00%	8.00%	0.00%
Centene Corp	CNC	541.479	61.65	33,382.18	0.12%			8.43%	0.01%
Martin Marietta Materials Inc	MLM	61.804	446.41	27,589.92	0.10%	0.66%	0.00%	19.03%	0.02%
Teradyne Inc	TER	154.014	107.87	16,613.49	0.06%	0.41%	0.00%	15.00%	0.01%
PayPal Holdings Inc	PYPL	1098.037	62.51	68,638.29	0.24%			15.96%	0.04%
Tesla Inc	TSLA	3173.994	258.08	819,144.37	2.89%			16.00%	0.46%
Arch Capital Group Ltd	ACGL	372.954	76.86	28,665.24	0.10%			14.50%	0.01%
Dow Inc	DOW	703.075	54.56	38,359.77	0.14%	5.13%	0.01%	2.78%	0.00%
Everest Group Ltd	EG	43.404	360.68	15,654.95		1.83%		33.24%	
Teledyne Technologies Inc	TDY	47.075	418.3	19,691.47	0.07%			6.36%	0.00%
News Corp	NWSA	379.585	21.49	8,157.28	0.03%	0.93%	0.00%	8.00%	0.00%
Exelon Corp	EXC	994.299	40.12	39,891.28	0.14%	3.59%	0.01%	5.30%	0.01%
Global Payments Inc	GPN	259.994	126.69	32,938.64	0.12%	0.79%	0.00%	13.63%	0.02%
Crown Castle Inc	CCI	433.679	100.5	43,584.74		6.23%			
Aptiv PLC	APTV	282.824	101.45	28,692.49	0.10%			12.44%	0.01%
Align Technology Inc	ALGN	76.534	370.14	28,328.29	0.10%			17.54%	0.02%
Illumina Inc	ILMN	158.3	165.22	26,154.33				-32.22%	
Kenvue Inc	KVUE	1914.894	23.05	44,138.31		3.47%			
Targa Resources Corp	TRGP	223.712	86.25	19,295.16	0.07%	2.32%	0.00%	15.00%	0.01%
LKQ Corp	LKQ	267.556	52.53	14,054.72		2.09%			
Zoetis Inc	ZTS	460.317	190.51	87,694.99	0.31%	0.79%	0.00%	10.91%	0.03%
Equinix Inc	EQIX	93.565	781.38	73,109.82	0.26%	1.75%	0.00%	15.43%	0.04%
Digital Realty Trust Inc	DLR	302.709	131.72	39,872.83	0.14%	3.70%	0.01%	6.59%	0.01%
Molina Healthcare Inc	MOH	58.3	310.12	18,080.00	0.06%			11.74%	0.01%
Las Vegas Sands Corp	LVS	764.447	54.86	41,937.56		1.46%			

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of August 31, 2023
[5] Source: Bloomberg Professional as of August 31, 2023
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of August 31, 2023
[9] Equals [7] x [8]
[10] Source: Bloomberg Professional, as of August 31, 2023
[11] Equals [7] x [10]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized Natual Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.59%	4.12%	5.46%
AVERAGE	10.39%	4.48%	5.91%
MEDIAN	10.28%	4.47%	5.94%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.921433
R Square	0.849038
Adjusted R Square	0.847791
Standard Error	0.003968
Observations	123.000000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.000000	0.010714	0.010714	680.528547	0.000000
Residual	121.000000	0.001905	0.000016		
Total	122.000000	0.012619			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0848	0.0011	80.7706	0.0000	0.0828	0.0869	0.0828	0.0869
U.S. Govt. 30-year Treasury	(0.5745)	0.0220	(26.0869)	0.0000	(0.6181)	(0.5309)	(0.6181)	(0.5309)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.21%	6.06%	10.27%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024) [5]	4.04%	6.16%	10.20%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.30%	10.10%
Average			10.19%

Notes:
[1] Source: Regulatory Research Associates, rate cases through August 31, 2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of August 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 9, September 1, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084831 + (-0.574529 x Column [7])
[9] Equals Column [7] + Column [8]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
Atmos Energy Corporation	ATO	17.48	1.66
NiSource Inc.	NI	11.15	1.83
Northwest Natural Gas Company	NWN	1.49	1.20
ONE Gas Inc.	OGS	4.25	1.60
Spire, Inc.	SR	3.20	1.18
Median		4.25	1.60

Montana-Dakota ND		
Test Year Rate Base ($millions)	[3]	$ 216.97
Company Proposed Common Equity Ratio	[4]	50.19%
Implied Common Equity ($millions)	[5]	$ 108.89
Implied Market Capitalization ($millions)	[6]	$ 174.15
Market Capitalization of Proxy Group (median) ($millions)	[7]	$ 4,245.09
As % of Proxy Group Market Capitalization (median)	[8]	4.10%

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10		[9] Market Capitalization of Largest Company ($ millions)	[10] Size Premium
1-Largest		2,203,381.29	-0.26%
2		31,316.51	0.45%
3		12,323.85	0.57%
4		5,916.02	0.58%
5		3,769.88	0.93%
6		2,365.08	1.16%
7		1,389.12	1.37%
8		782.38	1.18%
9		373.88	2.15%
10-Smallest		218.23	4.83%
Montana-Dakota ND Implied Market Capitalization	[6]	174.15	4.83%
Proxy Group Market Capitalization (median)	[7]	4,245.09	0.58%
Size Premium	[11]		4.25%

Notes:
[1]-[2] S&P Capital IQ Pro, equals 30-day average as of August 31, 2023
[3] Data provided by the Company
[4] Data provided by the Company
[5] Equals [3] x [4]
[6] Equals [5] x median market-to-book ratio of proxy group
[7] Equals median market capitalization of proxy group x 1000
[8] Equals [6] / [7]
[9]-[10] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2022
[11] Size Premium of Montana-Dakota ND less Size Premium of Proxy Group

FLOTATION COST ADJUSTMENT

Company	Ticker	[1] Date [i]	[2] Shares Issued (000)	[3] Offering Price	[4] Under-writing Discount [ii]	[5] Offering Expense ($000)	[6] Net Proceeds Per Share	[7] Total Flotation Costs ($000)	[8] Gross Equity Issue Before Costs ($000)	[9] Net Proceeds ($000)	[10] Flotation Cost Percentage
MDU Resources Group	MDU	2/4/2004	2,300	23.32	0.793	350	22.37	2,174	53,636	51,462	4.05%
MDU Resources Group	MDU	11/19/2002	2,400	24.00	0.720	193	23.20	1,921	57,600	55,680	3.33%
Total								$ 4,094.40	$ 111,236.00	$ 107,141.60	
								WEIGHTED AVERAGE FLOTATION COSTS			3.681%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount is calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[11] Annualized Dividend	[12] Stock Price	[13] Dividend Yield	[14] Expected Dividend Yield	[15] Expected Dividend Yield Adjusted for Flotation Costs	[16] Value Line Earnings Growth	[17] Yahoo! Finance Earnings Growth	[18] Zacks Earnings Growth	[19] Average Earnings Growth	[20] Cost of Equity: Mean Growth Rate	[21] Cost of Equity Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$2.96	$118.09	2.51%	2.60%	2.70%	7.00%	7.50%	7.30%	7.27%	9.86%	9.96%
NiSource Inc.	NI	$1.00	$26.94	3.71%	3.86%	4.00%	9.50%	6.70%	7.00%	7.73%	11.59%	11.74%
Northwest Natural Gas Company	NWN	$1.94	$41.31	4.70%	4.80%	4.98%	6.50%	2.80%	3.70%	4.33%	9.13%	9.31%
ONE Gas, Inc.	OGS	$2.60	$76.19	3.41%	3.51%	3.64%	6.50%	5.00%	5.00%	5.50%	9.01%	9.14%
Spire, Inc.	SR	$2.88	$60.77	4.74%	4.88%	5.07%	8.00%	n/a	4.20%	6.10%	10.98%	11.17%
Mean											10.12%	10.27%
Median											9.86%	9.96%
Flotation Cost Adjustment (Mean) [22]												0.15%
Flotation Cost Adjustment (Median) [23]												0.10%

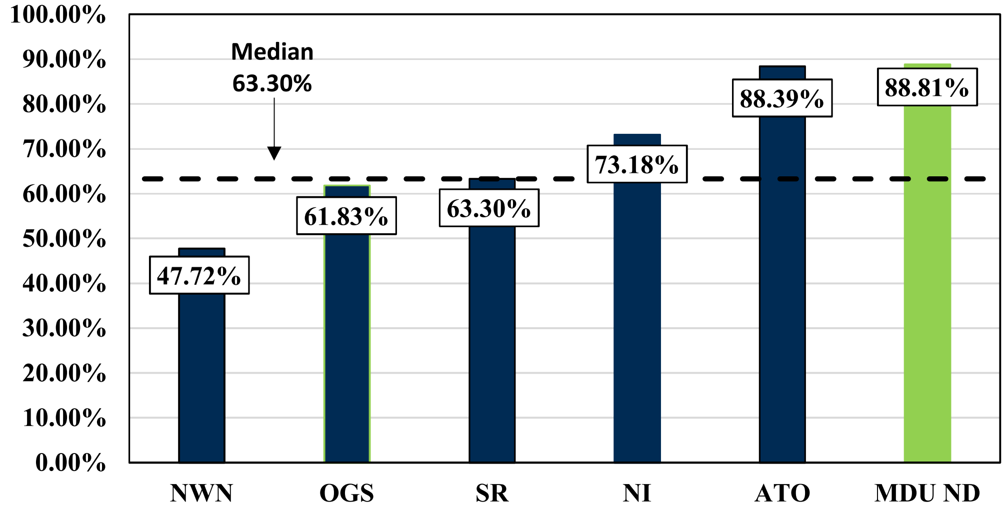
Notes:
[1] - [5] Source: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated November 19, 2002
[6] Equals [9]/[2]
[7] Equals [5] + ([4] x [2])
[8] Equals [2] x [3]
[9] Equals [8] - [7]
[10] Equals [7] / [8]
[11] Bloomberg Professional
[12] Bloomberg Professional, equals 30-day average as of August 31, 2023
[13] Equals [11] / [12]
[14] Equals [13] x (1 + 0.5 x [19])
[15] Equals [14] / (1 − Flotation Cost)
[16] Value Line
[17] Yahoo! Finance
[18] Zacks Investment Research
[19] Equals Average of [16], [17], [18]
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals [21] (Mean) − [20] (Mean)
[23] Equals [21] (Median) − [20] (Median)

2024-2028 CAPITAL EXPENDITURES AS A PERCENTAGE OF 2022 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2024	2025	2026	2027	2028	2024-2028 Cap. Ex. / 2022 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$ 18.70	$ 18.50	$ 18.30	$ 18.30	$ 18.30	
Common Shares Outstanding			$ 155.00	$ 162.50	$ 170.00	$ 170.00	$ 170.00	
Capital Expenditures			$ 2,898.50	$ 3,006.25	$ 3,111.00	$ 3,111.00	$ 3,111.00	88.39%
Net Plant		$ 17,240						
NiSource Inc.	NI							
Capital Spending per Share			$ 6.55	$ 6.65	$ 6.75	$ 6.75	$ 6.75	
Common Shares Outstanding			$ 420.00	$ 430.00	$ 440.00	$ 440.00	$ 440.00	
Capital Expenditures			$ 2,751.00	$ 2,859.50	$ 2,970.00	$ 2,970.00	$ 2,970.00	73.18%
Net Plant		$ 19,843						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$ 7.75	$ 7.63	$ 7.50	$ 7.50	$ 7.50	
Common Shares Outstanding			$ 37.50	$ 38.75	$ 40.00	$ 40.00	$ 40.00	
Capital Expenditures			$ 290.63	$ 295.47	$ 300.00	$ 300.00	$ 300.00	47.72%
Net Plant		$ 3,114						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$ 11.85	$ 12.18	$ 12.50	$ 12.50	$ 12.50	
Common Shares Outstanding			$ 55.50	$ 56.25	$ 57.00	$ 57.00	$ 57.00	
Capital Expenditures			$ 657.68	$ 684.84	$ 712.50	$ 712.50	$ 712.50	61.83%
Net Plant		$ 5,629						
Spire, Inc.	SR							
Capital Spending per Share			$ 12.85	$ 12.60	$ 12.35	$ 12.35	$ 12.35	
Common Shares Outstanding			$ 53.00	$ 54.00	$ 55.00	$ 55.00	$ 55.00	
Capital Expenditures			$ 681.05	$ 680.40	$ 679.25	$ 679.25	$ 679.25	63.30%
Net Plant		$ 5,370						
Montana-Dakota	MDU ND							
Capital Expenditures [8]			$ 35.94	$ 47.12	$ 34.08	$ 41.03	$ 32.11	88.81%
Net Plant [9]		$ 214.24						

Notes:
[1] - [6] Value Line, dated August 25, 2023
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Provided by the Company
[9] Provided by the Company



Projected CAPEX/2022 Net Plant

	Company	Ticker	Projected CAPEX / 2022 Net Plant
1	Northwest Natural Gas Company	NWN	47.72%
2	ONE Gas, Inc.	OGS	61.83%
3	Spire, Inc.	SR	63.30%
4	NiSource Inc.	NI	73.18%
5	Atmos Energy Corporation	ATO	88.39%
6	Montana-Dakota	MDU ND	88.81%
	Proxy Group Median		63.30%
	Montana-Dakota as % of Median		1.40

Notes:
Schedule 11, pg. 1 col. [7]

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
Atmos Energy Corporation									
	Atmos Energy Corporation	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Louisiana	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Mississippi	Gas	Historical	Partial	Yes	No	Yes	Yes
	Atmos Energy Corporation	Tennessee	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
NiSource Inc.									
	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Partial	No	No	Yes	Yes
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	No	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Historical	Partial	No	No	Yes	Yes
Northwest Natural Gas Company									
	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No
ONE Gas, Inc.									
	Kansas Gas Service Co.	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Partial	Yes	No	Yes	No
	Texas Gas Service Co. Inc.	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
Spire, Inc.									
	Spire Alabama Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Gulf Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Missouri Inc.	Missouri	Gas	Partially Forecast	Partial	No	No	Yes	Yes
Proxy Group Totals				Fully Forecast 8					
				Partially Forecast 3				Yes 19	Yes 15
				Historical 10				No 2	No 6
				% Forecast 52.4%				% Yes 90.5%	% Yes 71.4%
Montana-Dakota [7]		North Dakota	Gas	Fully Forecast	Partial	No	No	Yes	No

Notes:
[1] Regulatory Research Associates, Rate Case History, effective as of August 31, 2023, Company Tariffs, Company Form 10-K.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[3] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[7] Data provided by the Company

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
One Gas Inc.	OGS	58.23%	61.09%	60.04%	59.79%
Spire Inc.	SR	47.30%	49.08%	52.75%	49.71%
Proxy Group					
MEAN		53.49%	53.80%	53.49%	53.59%
LOW		47.30%	44.08%	41.92%	44.57%
HIGH		60.01%	61.09%	60.04%	59.79%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS		60.99%	59.85%	60.42%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
Spire Alabama Inc.	SR	52.01%	56.67%	58.82%	55.84%
Spire Gulf Inc.	SR	41.35%	41.14%	39.49%	40.66%
Spire Mississippi Inc.	SR		39.18%	38.74%	38.96%
Spire Missouri Inc.	SR	45.49%	46.20%	50.65%	47.45%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
One Gas Inc.	OGS	41.77%	38.91%	39.96%	40.21%
Spire Inc.	SR	39.78%	39.42%	37.24%	38.82%
Proxy Group					
MEAN		42.56%	41.69%	42.18%	42.15%
LOW		39.78%	38.91%	37.24%	38.82%
HIGH		45.83%	45.15%	46.45%	45.59%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS		39.01%	40.15%	39.58%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
Spire Alabama Inc.	SR	33.01%	40.18%	32.80%	35.33%
Spire Gulf Inc.	SR	38.77%	42.00%	57.90%	46.22%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	42.91%	39.42%	38.72%	40.35%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%	0.00%

Proxy Group					
MEAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	12.92%	11.49%	10.01%	11.47%
Proxy Group					
MEAN		3.95%	4.51%	4.33%	4.26%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		12.92%	11.49%	11.63%	11.47%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	14.98%	3.15%	8.38%	8.83%
Spire Gulf Inc.	SR	19.88%	16.86%	2.61%	13.12%
Spire Mississippi Inc.	SR		60.82%	61.26%	61.04%
Spire Missouri Inc.	SR	11.60%	14.38%	10.63%	12.20%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-___

Direct Testimony

Of

Hart Gilchrist

Q. Please state your name and business address.

A. My name is Hart Gilchrist, and my business address is 555 South Cole Road, Boise, Idaho 83709.

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

A. I am the Vice President of Safety, Process Improvement, and Operations Systems of Montana-Dakota Utilities Co. (Montana-Dakota or Company), Cascade Natural Gas Corporation, and Intermountain Gas Company (Intermountain Gas), all subsidiaries of MDU Resources Group, Inc., and Great Plains Natural Gas Co., a division of Montana-Dakota, collectively the MDU Utilities Group.

Q. Please describe your duties and responsibilities with MDU Utilities Group.

A. I am responsible for the safety, technical training, Safety Management System (SMS), Quality, GIS, and Operations Systems (technology implementations and support functions) for MDU Utilities Group.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Finance and Marketing, from the University of Idaho and a Master of Business Administration from Boise State University. I served on the United Way of Treasure Valley Board of Directors, Boise State University College of Business and Economics Advisory Board, College of Western Idaho Foundation Board, American Gas Association Managing Committee, Northwest Gas Association Board, and Boise Chamber of Commerce Advisory Board. I began working for Intermountain Gas in 1994 as an Engineering Technician and have been in my current capacity since July 2015. Prior to advancing into my current role, I held numerous positions in the operations department.

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

A. Yes. I have previously presented testimony before the Public Utilities Commission of Idaho.

Q. What is the purpose of your testimony?

A. I will provide support for Montana-Dakota's rate case application regarding Montana-Dakota's Work and Asset Management system deployment.

WORK AND ASSET MANAGEMENT

Q1. Please describe the Work and Asset Management system (Maximo)?

A. Maximo is an integrated software solution storing assets, work orders, work order tracking information, and maintenance and compliance schedules.

Montana-Dakota is in the second phase of a multi-phase implementation of Maximo. The initial phase was for maintenance work and was implemented in 2019-2021. The maintenance phase included equipment maintenance and all gas compliance maintenance (e.g., corrosion control, leak survey, atmospheric corrosion survey, patrolling, measurement, and equipment maintenance). The current phase is gas construction and is being implemented in 2022-2024. This will include the full lifecycle of construction – initiate, design, estimate, plan/schedule, construct, close out and documentation of construction work. This will be a full electronically driven construction process integrated to core systems, reducing touchpoints and data entry.

Q2. Why did Montana-Dakota undertake this project?

A. Maximo will provide six primary benefits:

1. Align operations business processes across the enterprise.

2. Replace fragmented and non-integrated operations technology systems/processes with one unified work and asset management system – improving efficiency of implementation and support.
3. Reduce touch points and redundancy.
4. Gain enterprise-wide insight into asset tracking, construction, maintenance, compliance, and costs. This includes tracking Operation's Key Performance Indicators (KPI's).
5. Drive consistent work flows across the enterprise, improving work product results.
6. Improve the user experience with consistent field data entry technology – lowers training needs and limits confusion and errors.

Q3. What is the project timeline?

A. Montana-Dakota is in the second phase of a three-phase implementation of Maximo. The timeline for the full gas maintenance and construction implementation is 2019-2024.

- Phase I was maintenance work and was implemented in 2019-2021. This phase included equipment maintenance, electric distribution system maintenance; such as, line patrols, substation maintenance, and electric work order tracking/work flow.
- Phase II, the phase that is being considered in this case, is

construction and is being implemented in 2023-2024. This phase includes the full lifecycle of construction – initiate, design, estimate, plan/schedule, construct, close out and document construction work. This is a full electronically driven construction process integrated to core systems, reducing touchpoints and data entry.

- Phase III is the implementation of electric transmission, electric generation and environmental sections and is planned for 2024-2025.

Q4. How will Montana-Dakota customers benefit from the project?

A. Customers will benefit through the elimination of redundancy of systems and the inherent resources that are necessary to support multiple systems to complete the same or similar tasks. The electronic system will improve the overall quality of information being collected in the field and provide a central data repository for information related to all utility maintenance and construction activity. This will improve the safe operation of the system through higher quality gas facility installations.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The Company did due diligence when selecting Maximo. An exploratory team was formed in 2017 and evaluated the implementation of work and asset management systems across the gas and electric utility industry. It was determined Maximo was the best choice because it is a lower cost solution, the system integrates well to disparate systems, and Maximo is mature and proven compared to other Work and Asset Management systems. The Company visited other utilities to learn best practices for implementing Work and Asset Management systems. This information was used to develop the phased approach and to leverage internal resources to develop expertise to support the system going forward. The strategy has worked thus far through the successful, on time and on budget implementation of Phase I.

Q6. What are the costs of the project?

A. The cost of the Work and Asset Management system allocated to the North Dakota Gas jurisdiction is $2,072,156 as shown as FP-100550 on Statement B, Schedule B-2, page 9.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony

Of

Micheal Schoepp

Q. Please state your name and business address.

A. My name is Micheal Schoepp, and my business address is 400 North 4th Street, Bismarck, North Dakota 58501.

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

A. I am the Director of Operation Services for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade") and Intermountain Gas Company ("Intermountain").

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

A. I have responsibility and oversight for the compliance, damage prevention and public awareness programs.

Q. Please outline your educational and professional background.

A. I am a graduate of North Dakota State University with a Bachelor of Science Degree in Mechanical Engineering.

I began my career in 2004 as a gas engineer with Montana-Dakota Utilities in Bismarck, ND. I have held positions of increasing responsibility including Senior Engineer and Region Gas Superintendent. I have been the Director of Operation Services since 2016.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's use of Picarro Leak Survey Equipment and Technology and the costs associated and elevated pressure on customers meters.

PICARRO LEAK SURVEY EQUIPMENT

Q. What is the Picarro Leak Survey Equipment (Picarro)?

A. Picarro is an Advanced Mobile Leak Detection (AMLD) technology. Picarro uses laser spectroscopy and data analytics to measure and locate natural gas leaks with high accuracy and precision.

Q. What is the difference between Picarro and the current process?

A. Montana-Dakota's current leak surveys are performed by walking with flame ionization units.

The Picarro system is attached to a vehicle which then drives an area approximately three times. Each time the vehicle is driven in a different direction to account for wind and to determine the perimeter of methane plume. The driving survey is performed during evening and night hours because there is typically less traffic and less wind during these hours.

Q. What are the benefits using Picarro?

A. The Picarro system is a more efficient and accurate leak surveying system than the traditional walking survey. The methane sensitivity detected by Picarro is parts per billion versus the walking survey sensitivity which is parts per million. Because of this heighten sensitivity, Picarro can sense methane in the air while driving. This will give the Company the ability to perform leak survey in a timelier manner and identify more leaks on its system.

The Picarro system also offers a safer option for employees than the walking survey. In the walking survey, employees are moving along and crossing roads to perform the leak survey which can be hazardous during times of high traffic volumes. Because the Picarro leak survey is performed by driving a vehicle and can also be done during times when traffic is lighter, it is normally done in the evenings or at night. Montana-Dakota can only perform walking survey during the day. The surveyors follow maps on tablets to make sure we accurately survey over the facilities underground. Due to safety concerns, walking surveys cannot be performed during night hours.

Additionally, there is a proposed pipeline code rule change for leak surveying. The current code requires non-business districts to be leak surveyed once every five years. The proposed rule would change the non-business leak surveying to be required once every 3 years. Montana-Dakota currently performs its non-business leak survey’s every 4 years. Picarro would help Montana-Dakota transition to a leak surveying pattern that meets the proposed timeline because it would be able to survey a larger area in the same time and keep its costs relatively flat.

Finally, the Picarro system would not require access to customers' meters. The current walking survey requires that a Montana-Dakota employee or contractor to walk the natural gas lines and leak survey over the lines to sense methane gas. Because access to customers' yards has also been more of an issue, due to dogs, locked fences, etc. Picarro would allow for the leak surveying to be completed without disrupting the customer or needing access to customers yards.

Q. What are the capital cost estimates of the project?

A. The current capital cost is $531,831 as shown as FP-324578 on Statement B, Schedule B-2, page 7. However, Montana-Dakota did reduce Operations and Maintenance Expenses associated with Subcontract Labor for 2024 due to this purchase. Survey's will now be performed by Montana-Dakota employees versus the current process of using subcontractors. This will be discussed more in the testimony of Ms. Tara R. Vesey.

<u>ELEVATED PRESSURE</u>

Q. What is elevated pressure on residential meter sets?

A. The standard delivery pressure for a residential gas meter set is about .25 PSI (pounds per square inch). An elevated pressure for a residential gas meter set would be 2 PSI typically.

Q. Why provide elevated pressure to residential meters?

A. On occasion, the Company receives requests from mechanical contractors in its service territory for elevated pressure for a customer's service. As way of background, the pipe installed inside a residential home can vary from home to home, depending on the size and equipment of the house. Typically contractors will use smaller pipe inside a home, but piping a larger home would be easier with a higher gas pressure being provided. Home remodels and fuel source conversions can be easier (and less costly) if Montana-Dakota is able to provide the contractor (and customer) with the option to raise the gas pressure inside a customer's home versus re-piping the home or installing a second gas meter at a different location.

Q. What is Montana-Dakota's current policy for elevated pressure gas meters?

A. The current Montana-Dakota policy is to provide elevated pressure to large commercial customers with connected loads of 500,000 BTU's or larger. The residential customers are provided elevated pressure if the home is converting from another fuel source, has a connected load of 1,000,000 BTU's or larger or the gas equipment requires a higher pressure to operate.

As is covered in more detail in the Direct Testimony of Ms. Stephanie Bosch, Montana-Dakota is proposing a change to the residential rate structures to recognize elevated pressure on a residential service. The customers would pay a higher basic service charge for these elevated pressure gas meter sets.

Q. Are there additional costs or requirements related to a customer's service with elevated pressure?

A. Montana-Dakota would install a more expensive regulator to provide the high delivery pressure to the customer which would need to be checked 30 days after installation. The customer would also need to install regulators at each appliance to regulate down the pressure for each appliance to operate.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony
of
Shawn Nieuwsma

Q. Please state your name and business address.

A. My name is Shawn Nieuwsma, and my business address is 400 North 4th Street, Bismarck, ND 58501.

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

A. I am the Gas Supply Manager for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company") and Great Plains Natural Gas Co. ("Great Plains").

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

A. As the Gas Supply Manager, I am responsible for the development and execution of the Company's natural gas commodity and services portfolio. I also have managerial responsibility and oversight of natural gas scheduling/balancing, demand forecasting/modeling, and large volume customer measurement data acquisition. Our department's primary purposes are to ensure the delivery of natural gas to our city gates at our customers' service level expectations in a cost-effective manner.

Q. Please outline your educational and professional background.

A. I graduated from North Dakota State University with a Bachelor of Science degree in Industrial Engineering and Management. In June 2015, I completed the Utility Executive Course at the University of Idaho in Moscow, ID.

I started my career with Montana-Dakota in 2011 as a Gas Supply Analyst. During my tenure with the Company, I increased my level of responsibilities to Gas Supply Engineer and now to my current position as Gas Supply Manager, which I have held for the past ten years.

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

A. Yes. I have previously presented testimony before the Minnesota Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how Montana-Dakota determines a need to increase the capacity ("upgrade") to a Town Border Station (TBS) and to summarize three specific TBS upgrades.

OVERVIEW OF TOWN BORDER STATION (TBS) REVIEW PROCESS

Q. Please describe the term TBS as it applies to your testimony.

A. A TBS refers to relief, regulation, metering, and other applicable facilities related to custody transfer of natural gas between a transportation service provider (TSP)[1] and a local distribution company. I will use TBS when referring

[1] The only applicable TSP for this testimony is WBI Energy Transmission (WBI).

to delivery point[2] or city gate because they have generally the same meaning in the context of this testimony.

Q. Please describe Firm Transportation Service Capacity and its value to customers.

A. Firm Transportation Service Capacity (Contract Capacity) is held through firm transportation service agreements (FTSAs) with TSPs to 1.) receive natural gas on the TSP's transmission system and 2.) to deliver natural gas to and through contractually defined TBSs. Firm is the highest level of service (highest priority) and is practically limited to the engineering-determined Design Capacity of a TBS. Utilities' primary customers do not have immediate access to alternative heating energy sources; therefore, using this highest priority of service is the best way to ensure energy delivery all year and in any conditions.

Q. Please describe the process the Company uses to determine Contract Capacity requirements to a TBS.

A. The first step is to calculate design day delivery requirements. Historical consumption (energy) is recorded at each TBS and is regressed against corresponding heating degrees to create a regression formula[3]. Design heating degrees[4] are applied to this formula yielding a design day demand. This evaluation is performed on an annual basis or sub annually as needed.

The Company then compares each TBS's Design Day Demand

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[2] Delivery point is more appropriate when describing contractual transportation capacity because such capacity may include multiple TBSs. All three communities discussed have a single TBS.
[3] Calculation and use of formula will or will not include interruptible load depending on application of formula.
[4] Highest heating degrees in past 30 years.

to its Contract Capacity. Montana-Dakota must consider acquiring incremental Contract Capacity if a TBS's firm Design Day Demand exceeds its Contract Capacity.

Q. Why might Design Day Demand change?

A. Design day demand dynamics are driven by changes to both/either customer count and/or customer usage patterns. Typically, communities with limited growth realize limited design day demand changes. Larger and growing communities, particularly those with large commercial and industrial growth may see design day demand increases each year.

In rare circumstances, Design Day Demand can decrease. This is observed and addressed in communities with a declining population or communities that have lost load through efficiency improvements or customer departure.

Q. Has Montana-Dakota seen load growth that has increased its Design Day Demand?

A. Yes, load has been realized in various locations throughout the Company's service territory.

Q. Has this load growth cause any TBS's Design Day Demand to exceed Contract Capacity?

A. Yes, such growth has driven some TBS's Firm Design Day Demand above the subscribed Contract Capacity or to a level below the targeted Reserve Margin.

Q. What is meant by Reserve Margin?

A. Reserve margin refers to the amount of Contract Capacity above the Firm Design Day Demand intended to provide a level of safety for unaccounted load growth, new design heating degrees, TSP fuel-in-kind, and regression error. Montana-Dakota's Contract Capacity target is 5%-10% above the Design Day requirement. This amount strikes a balance between ensuring that all firm customers are served on a Design Day[5] while avoiding costs for unnecessary Contract Capacity.

Q. Have there been any methodology changes to the calculation of Firm Design Day Demand or use of Reserve Margin in recent history?

A. No, the practice of using linear regressions to calculate Firm Design Day Demand and the use of a 5%-10% reserve margin has been used effectively for the duration of my career.

Q. How is incremental Contract Capacity typically acquired for a particular TBS?

A. Incremental Contract Capacity to a particular TBS is typically accomplished by reallocating Contract Capacity from one TBS with sufficient Reserve Margin to the deficient TBS. This strategy works well when a larger TBS, with an acceptable Reserve Margin can sacrifice capacity to a smaller, deficient TBS. There is relatively little negative impact on the lager TBS and relatively high impact to the smaller TBS.

[5] Allows for slightly colder than current design day temperatures and considers design day demand formula error. Also allows for consideration of applied fuel and lost and unaccounted for percentages.

This reallocation of Contract Capacity may be done if the two involved TBS's have common upstream facilities/constraints, and the acquiring TBS has adequate Design Capacity. All customers benefit from these reallocations by avoiding incremental FTSA costs through the optimization of currently held capacity.

When Contract Capacity to a deficient TBS cannot be reallocated due to upstream facility constraints[6] or insufficient Design Capacity, a project involving facility expansion is required. Montana-Dakota will engage in transmission-level projects when upstream facility constraints exist[7]. The Company pursues individual TBS upgrades when Contract Capacity cannot be reallocated to a deficient TBS due strictly to Design Capacity limitations. Costs associated with the TBS upgrade are required regardless of upstream facility enhancements; therefore, Montana-Dakota strives to avoid upstream facility enhancement costs if possible.

Most transmission-level projects are completed and paid for through an incremental FTSA where the shipper pays the TSP through tariff or negotiated rate schedules. When Montana-Dakota participates in such projects, costs of such are recovered through the monthly Cost of Gas Adjustment. When there is not an incremental FTSA, costs are outside the scope of the Cost of Gas Adjustment and therefore capitalized by the Company.

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[6] Upstream facility constraints include but are not limited to compression limitations and pipeline capacity,
[7] For example, the recent "Valley Expansion Project" added 30,000 Mcf/day providing incremental Contract Capacity to several communities across Eastern and Central North Dakota.

Q. Can Contracted Capacity exceed a TBS's Design Capacity?

A. No, Contracted Capacity (firm) is limited to the TBS's Design Capacity.

Q. How is a TBS's Design Capacity determined?

A TBS's Design Capacity is determined by calculating the volumetric throughput of the most restrictive component(s) within a TBS against a variety of system-wide operating conditions. Particularly important is the TSP's guaranteed minimum delivery pressure of 200 psi, which is used throughout the system. Other considerations include but are not limited to natural gas velocity, outlet pressure, required pressure reduction, and in-line heating.

Q. What, if any changes, have been made to how TBS Design Capacity is determined?

A. With safety and reliability in mind, Design Capacity reviews are performed by the owner of each TBS. WBI Energy Transmission Inc. (WBI) has reported that several TBSs have undergone recent evaluations with a desire to lower gas velocity. Specifically, WBI has decreased its target velocity from 120 feet/second to 70 feet/second. This target was changed to reduce pipe and other component vibration, particularly at aging TBSs. Many of WBI's TBSs are the original facilities installed at the time transmission was extended to the served community.

Q. Are there any other factors that have caused Design Day Demand to exceed Design Capacity?

A. Yes. As part of an ongoing initiative to better monitor and control the transmission system, WBI has and continues to install higher frequency measurement equipment at many TBS. Specifically, WBI is now acquiring high-frequency (daily or sub-daily) measurement information where previous low-frequency measurement (weekly or monthly) was captured.

Q. How has read frequency increased Design Day Demand?

A. Increasing measurement read frequency (granularity) exposes its audience to a greater level of volatility. Both measurement peaks and valleys are exposed, particularly peaks because consumption ceilings are only determined by design cold conditions whereas most communities have a built-in base demand.

When measurement is acquired on a weekly or monthly basis, daily consumption was the sum of the change divided by the number of days in the read period. Enhanced granularity naturally exposes peaks, which typically only last a day or two.

Newly available peak measurement information creates new formulas from which Design Day Demand is calculated. This tends to increase the Design Day Demand and increases the contractual standard to which the Company must adhere.

Q. Why would read frequency be increased at a TBS?

A. Higher read frequency allows for better understanding and control of a transmission or distribution system. Daily measurement information allows a TSP to react more effectively to changes in operating conditions. Also, natural gas is transacted and scheduled primarily daily. The ability to allocate flow on the same daily basis is normal throughout the industry, especially as natural gas transportation infrastructure is highly utilized.

IDENTIFIED NEED FOR TBS UPGRADE

Q. Have you identified any TBS that requires a physical upgrade? If so, which TBSs?

A. Yes, the Company has identified and prioritized three North Dakota TBSs that require or will require a TBS upgrade. Those TBSs are Devils Lake, Grafton, and Washburn.

Q. Please compare the Firm Design Day Demand to the Contract Capacity and Design Capacity for each of these TBSs.

A. All units are dekatherms/day[8].

TBS	Design Day Demand	Contractual Capacity	Design Capacity	Contractual Reserve Margin
Devils Lake	6,292	6,458	6,459	2.6%
Grafton	3,023	3,210	3,209	6.2%
Washburn	831	605	503	-27.2%

[8] Capacity adjusted from volume to energy using applicable BTU of delivered natural gas.

<u>Devils Lake TBS Upgrade</u>

Q. Please summarize the reasons for prioritizing a Devils Lake TBS upgrade.

A. 1) Devils Lake TBS currently resides at a 2.6% reserve margin. This reserve margin is below the standard target of 5%.

2) Design Day Demand has increased significantly in the past five years. A regression analysis using November through February data from November 2016 through December 2018 determined design day forecast was 5,885 Dth. The current firm design day demand has grown to 6,292 Dth (6.9% increase).

3) The Company adds approximately 10-15 residential customers per year and approximately five commercial customers per year. While this customer count increase is not substantial, Montana-Dakota believes this growth will continue and TBS capacity, both Contract and Design, will be required to continue supporting this growth.

The need to increase Contract Capacity to Devils Lake has long been anticipated. Devils Lake was a key benefactor for the WBI "Valley Expansion Project" in 2018, gaining 750 Mcf/day. Montana-Dakota was prepared to incrementally reallocate Contract Capacity to Devils Lake as needed. At the time of the project, the posted Design Capacity of the Devils Lake TBS was approximately 8,700 Dth/day. Upon the TSP's recent review, the Design Capacity has been reduced to 6,459 Dth/day. This change has made the intended reallocation impossible.

Q. What is the expected cost for the Devils Lake TBS upgrade?

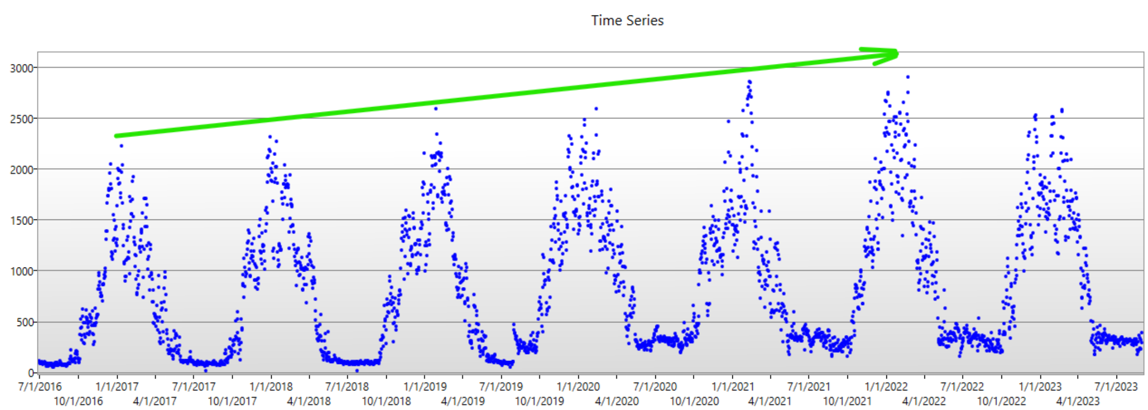
A. The cost of the Devils Lake TBS upgrade, allocated to North Dakota Gas, is $1,804,895 as shown on Statement B, Schedule B-2, pages 6 and 8 as FP-324652 and FP-324601.

<u>Grafton TBS Upgrade</u>

Q. Please summarize the reasons for prioritizing a Grafton TBS upgrade.

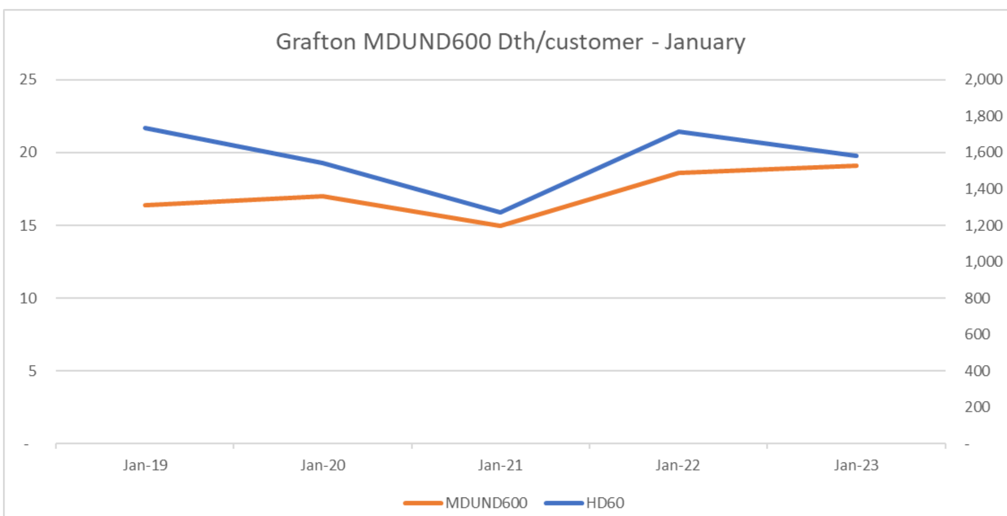
A. 1) Grafton currently has a 6.2% reserve margin, at the bottom of the Company's standard range.

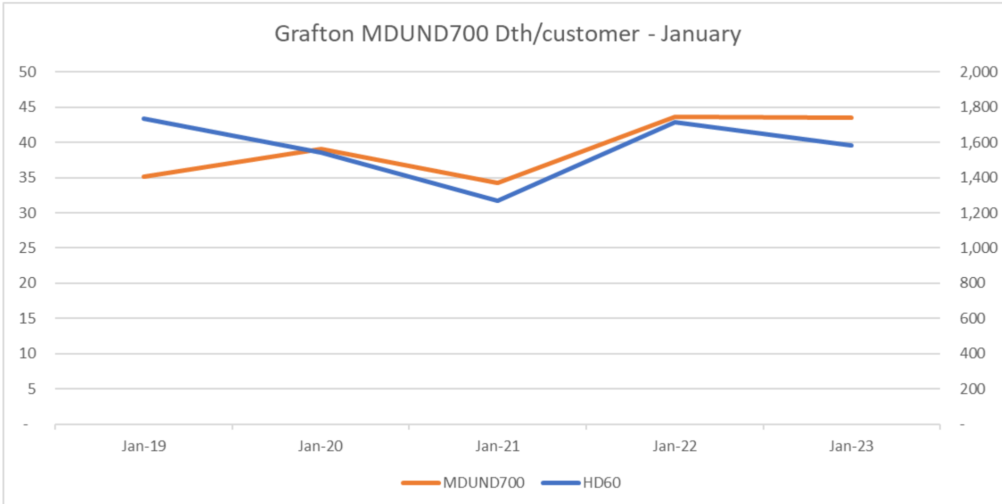
2) Grafton's firm customer consumption has been on an upward trajectory since at least 2016 experiencing increasing winter peak consumption nearly every year. The following graph displays each day's firm consumption since July 2016.

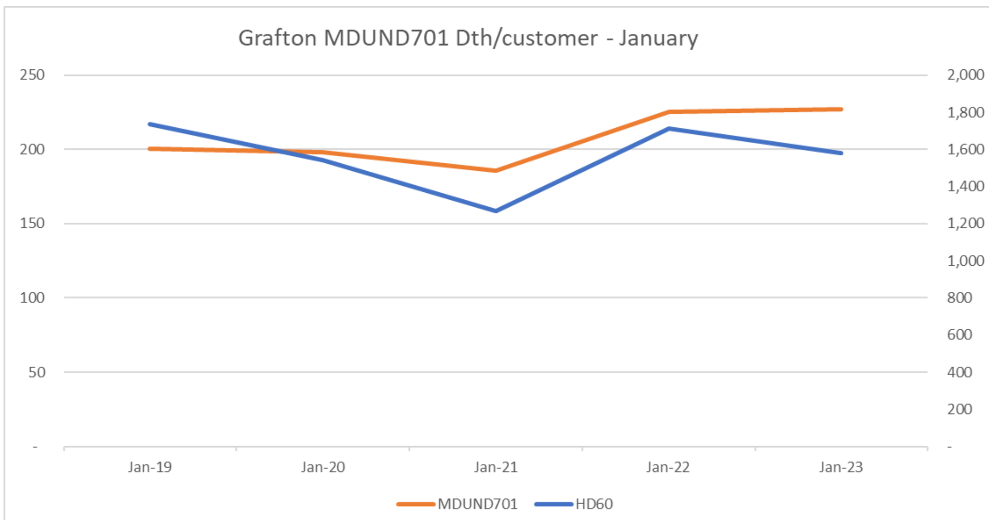


The realized maximum firm consumption occurred on February 21, 2022. On this date, Grafton's firm consumption was 2,903 Dth against only 74 heating degrees (heating degrees are more fully discussed in the testimony of Mr. Nathan A. Bensen). That is 19 fewer heating degrees than Grafton's design day temperature. Considering that each incremental heating degree projects approximately 30 incremental Dth of firm consumption, firm consumption was at risk of exceeding Contract Capacity.

The Company has observed peak heating season consumption per customer increase over the past several years. Considering that the realized heating degrees play a significant role in consumption, the following graphs represent January Dth/customer for the traditional firm rate classes. Within these graphs, we observe that customer use (orange) increases or decreases relative to the corresponding heating degrees (blue).







Each class exhibits increased consumption on a Dth/customer basis. While the Dth/customer increase appears small, the net load growth is substantial when multiplied by approximately 1,400 MDUND600 customers, 200 MDUND700 customers, and 65 MDUND701 customers.

Month	HD60	MDUND600	MDUND700	MDUND701
Jan-19	1,737	16	35	200
Jan-20	1,541	17	39	198
Jan-21	1,270	15	34	186
Jan-22	1,714	19	44	225
Jan-23	1,582	19	43	227
2019 to 2023 Δ		**17%**	**24%**	**13%**

3) A new large firm customer was added through the Company's Rate Schedule 74, "Firm General Contracted Demand Service" beginning in July 2019. This customer converted from Rate Schedule 81, "Transportation Service", with a contract demand of 414[9] Dth/day. This consumes approximately 13% of the Grafton TBS's current contractual capacity.

Grafton's TBS also benefitted from the completion of the "Valley Expansion Project" adding 230 Mcf/day of Contract Capacity. Also, like Devils Lake, Grafton's posted TBS Design Capacity was much higher at the time at approximately 5,300 Dth/day. That value has been reduced to 3,209 Dth which prohibits Montana-Dakota from executing its plan to grow into the Valley Expansion Project capacity.

Q. What is the expected cost for the Grafton TBS upgrade?

A. The cost of the Grafton TBS upgrade, allocated to North Dakota Gas, is $1,231,577 as shown on Statement B, Schedule B-2, pages 6 and 8 as FP-323638 and FP-323713.

[9] Increasing to 429 Dth/day pursuant to FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74.

<u>Washburn TBS Upgrade</u>

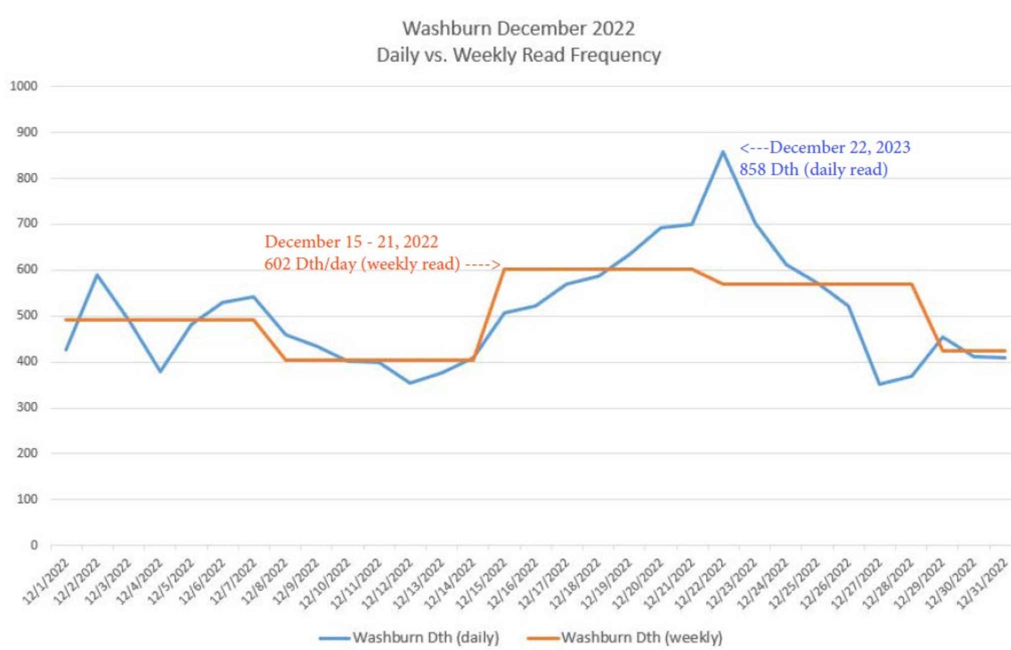
Q. Please summarize the reasons for prioritizing a Washburn TBS upgrade.

A. Washburn currently has a -27% reserve margin, well below the targeted 5%-10% reserve margin.

Q. Why is Washburn's reserve margin so low?

A. Washburn is the largest North Dakota TBS of 32 total TBSs that WBI improved from weekly or monthly read frequency to daily read frequency in September 2021. When a TBS's read frequency is less than daily, the allocated daily quantity is a mathematical average over the read period. With such, variability (including peaks) is greatly reduced.

The graph below demonstrates the impact by contrasting peak flows on a hypothetical weekly read frequency against the daily read frequency that was in place during December 2022.



Although each month's sum for weekly and daily read frequencies do match, applying a daily read frequency captures the peak day of 858 Dth, which is 43% greater than the 602 Dth/day weekly peak for the month.

Q. At what daily average temperature does Washburn's forecasted demand exceed its firm transportation capacity?

A. Washburn's firm demand exceeds capacity at 65 heating degrees or -5°F.

Q. How frequently do these temperature conditions occur?

A. Washburn's average daily temperature has been -5°F or colder 64 times in the past seven heating seasons.

Q. Has the Company struggled to deliver gas to Washburn since September 2021? How so or why not?

A. Since September 2021, The Company has only absorbed a single day's overrun penalty from WBI. Montana-Dakota has been able to effectively schedule and deliver natural gas to Washburn by optimizing available Contract Capacity reserved for larger, nearby communities such as Minot and Bismarck. This has been possible because prevailing upstream transportation gas pressures have well exceeded the 200 psi design criteria for the Washburn TBS.

Q. What is the expected cost for the Washburn TBS upgrade?

A. The cost of the Washburn TBS upgrade is $1,797,433 as shown on Statement B, Schedule B-2, pages 6 and 8 as FP-324458 and FP-324139.

<u>Summary of Projects</u>

Q. What alternative options to TBS upgrades has the Company considered?

A. There are two primary alternatives that the Company has considered. These are converting large firm customers to interruptible service and/or curtailing incremental customer growth.

Q. What issues does the Company have with converting customers from a firm to an interruptible level of service?

A. The lower costs associated with interruptible service no longer has the appeal it once had. Customers state that the investment, operation, and maintenance of backup systems exceed the realized savings. Furthermore, most new high efficiency appliances are no longer compatible for dual-fuel application.

Q. Do you expect additional TBS upgrades in the future at other North Dakota communities?

A. Yes. As mentioned earlier there were 32 TBSs transitioned from weekly/monthly read frequency to daily read frequency. Of those, 22 are North Dakota TBSs, each will need to be considered and appropriately prioritized.

The Company also sees TSPs continuing tightening of engineering determined Design Capacity. Long-term planning for transmission projects often includes eventual reallocation of Contract Capacity from larger TBSs to smaller TBSs.

Lastly, the Company will continue to lose transmission flexibility as WBI's transmission network continues to tighten. Bismarck and Minot continue to grow and expansion in Eastern North Dakota, including but not limited to the proposed Wahpeton Expansion project, will pressure the Company to obtain and maintain primary firm Contract Capacity.

Q. Does this complete your direct testimony?

A. Yes, this completes my testimony.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony
of
Renie Sorensen

Q. Please state your name and business address.

A. My name is Renie Sorensen, and my business address is 8113 West Grandridge Blvd. Kennewick, WA 99336.

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

A. I am the Manager of Engineering Services for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade") and Intermountain Gas Company ("Intermountain").

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

A. I have managerial responsibility and oversight for the review, planning, development and design of the Company's pipeline systems and technical facilities and I oversee our drafting services department.

Q. Please outline your educational and professional background.

A. I am a graduate of Utah State University with a Bachelor of Science Degree in Mechanical Engineering and received a Master of Business Administration Degree from Southern Utah University. I am a licensed professional engineer in the states of Washington and Oregon.

I began my career in 2011 as a gas engineer with Cascade Natural Gas Corporation in Kennewick, WA. I advanced through the Engineering Department until I was promoted to my current managerial position in 2018.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's project selection and budgeting process; and (2) describe and provide an update on construction activities, schedule, and costs estimates for the reinforcement projects in Minot, North Dakota and the town border station project in Jamestown, North Dakota.

OVERVIEW OF PROJECT SELECTION AND BUDGETING PROCESS

Q. What type of major capital projects does the Company typically perform?

A. The bulk of Montana-Dakota's major capital projects are pipeline replacement projects that have been identified for safety reasons and to reduce risk on Montana-Dakota's system, and system reinforcements or system expansions that have been identified as needed to ensure system reliability and to accommodate growth on the Company's system. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution system enhancements. Distribution system enhancements do not reduce demand, nor do they create additional supply; instead, enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing supply points.

Q. Please provide an overview of Montana-Dakota's identification and selection process for distribution enhancement projects.

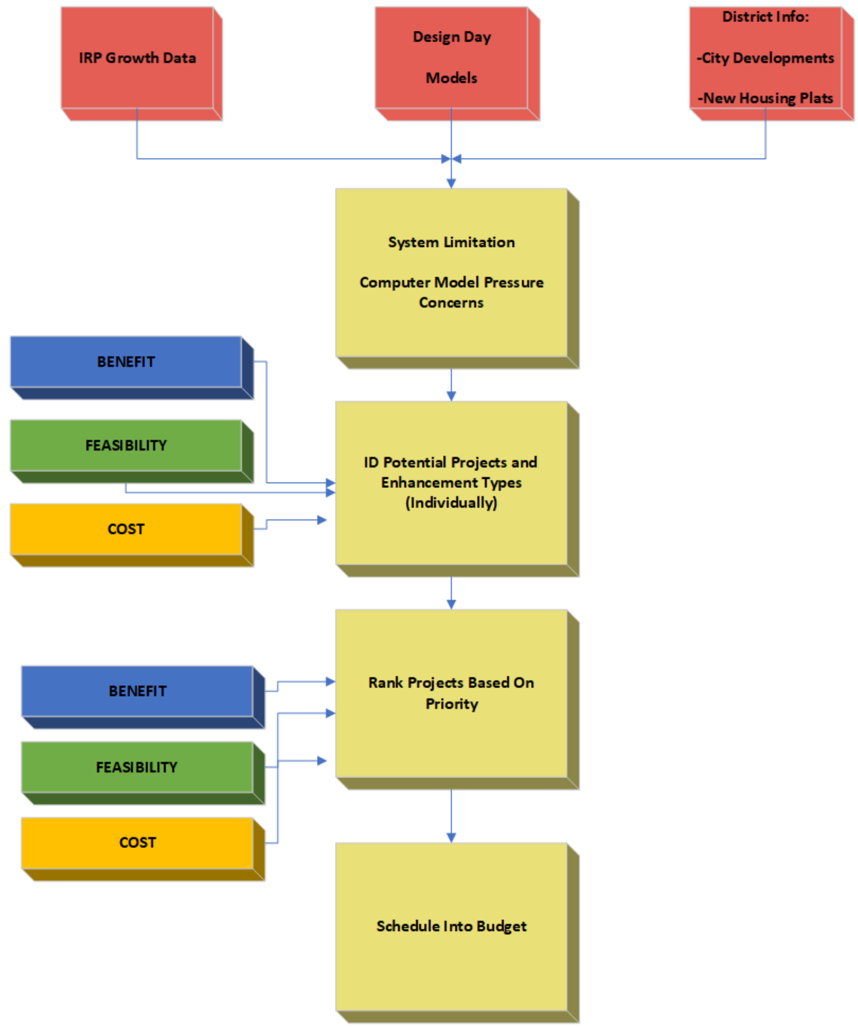
A. The Engineering Department works closely with Energy Services Representatives and district management to ensure the system is safe and reliable. Before expansion projects can be constructed to serve new customers, an engineering analysis is performed. Using system modeling software to represent cold weather scenarios, predictions can be made about the capacity of the system. As new groups of customers seek natural gas service, the models provide feedback on how best to serve them while maintaining reliable supply to our existing customers.

Another aspect of system planning involves city gate capacity analysis and forecasting. Over time, each gate station will take on more demand and it is Montana-Dakota's objective to stay ahead of potential reliability issues by predicting and identifying constraints on its system. Cold weather design day modeling allows Montana-Dakota to forecast necessary gate upgrades. Supervisory control and data acquisition (SCADA) communication technology utilized by Montana-Dakota allows verification of models with real time and historic gate flow and pressure data.

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification, and corresponding optimized combinations of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network. After developing a working demand study, the Company analyzes every system at peak cold weather conditions to identify areas where potential outages may occur. These constraint areas are then risk-ranked against each other to ensure the highest risk areas are corrected first and others are properly addressed in time. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient area of the distribution system;
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights-of-way, traffic issues, and minimal to no water, railroad, or major highway crossings, etc.;
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods;
- The segment of pipe that provides opportunity to add additional customers; and
- Total construction costs including restoration.

Once a project/reinforcement is identified, the Design Engineer or Energy Services Representative begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of review for the project/reinforcement selection criteria. Figure 1, below, provides a schematic representation of the distribution project process flow.



Q. Please provide an overview of Montana-Dakota's capital budgeting process.

A. Capital additions and changes are planned through the annual budgeting process using PowerPlan ("PP"), an accounting software application. The budget process begins with an individual (originator) creating specific funding projects in PP for all new projects to be included in the five-year capital budget. Originators are generally managers at the district level or engineering staff at the Company level. Sources of information for capital projects include the DIMP, TIMP, state and local government agencies, and internal Montana-Dakota personnel.

Funding projects are used to hold the capital budget estimates and will be linked to the capital work orders to be created when actual costs commence. A Fixed Asset Financial Analyst reviews the funding projects for proper setup. If the project is not considered a capital expenditure as it was submitted, it is rejected and sent back to the originator for revision, cancelled, or it is moved to Operations and Maintenance ("O&M") expense. After the review has been completed, the Fixed Asset Financial Analyst will add appropriate overheads. As discussed more fully in the testimony of Mr. Eric P. Martuscelli, blanket funding projects are used year after year to budget for high volume mass property work orders typically under $150,000 each.

Once all the funding projects have been updated with expenditures, various Company operating managers generate reports to show estimated expenditures and justification for each project. The managers perform the review of funding projects and see that any necessary changes are made to the estimate and that the project is supported. Reports are then generated by the budgeting personnel for review and approval by the Directors and Vice Presidents of the Utility Group. Any final budget changes are made, and the budgets are then presented to the Utility Group's President for review and approval. The final Utility Group budget is then presented to the MDU Resources CEO for review and approval. If the budget is approved by the MDU Resources CEO, the final review and approval occurs with the Board of Directors. At each stage of the review and approval process a project (or projects) can be challenged for appropriateness and removed from the capital budget or moved to another year within the five-year budget. The addition or removal of projects can also be impacted by other factors such as available capital and/or borrowing capacity, upon appropriate review to verify continued reliable and safe service.

After final approval, an approved budget version is created in PP, locked for entry and the funding projects and estimated amounts in the approved budget version are copied back to the working budget version. Project managers are notified that the budget has been approved and the funding projects are open for work order creation. Projects are monitored and updated throughout the year as part of the review process and to insure, as best as possible, that projects are completed on time and within the approved budget.

Q. For work that will be performed in 2024, how does the Company develop budgeted amounts?

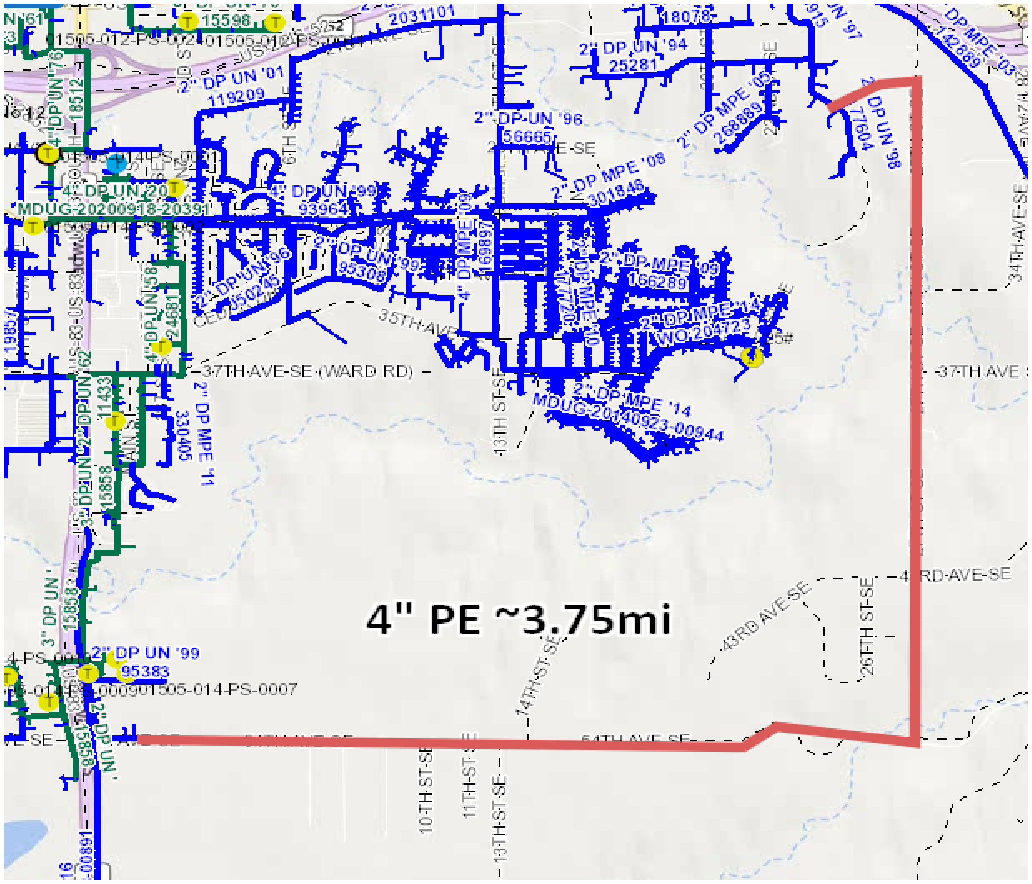
A. The Company's capital budgets were developed in June 2023, and the Company expects that its actual investment should not differ materially from the budgeted amounts for the projects that are not yet complete. Currently, Montana-Dakota is not aware of any immediate impacts to the construction schedules for its capital projects. The Company will provide updates regarding changes to budgeted amounts or actual investments, and any relevant changes in schedule, through discovery (as requested).

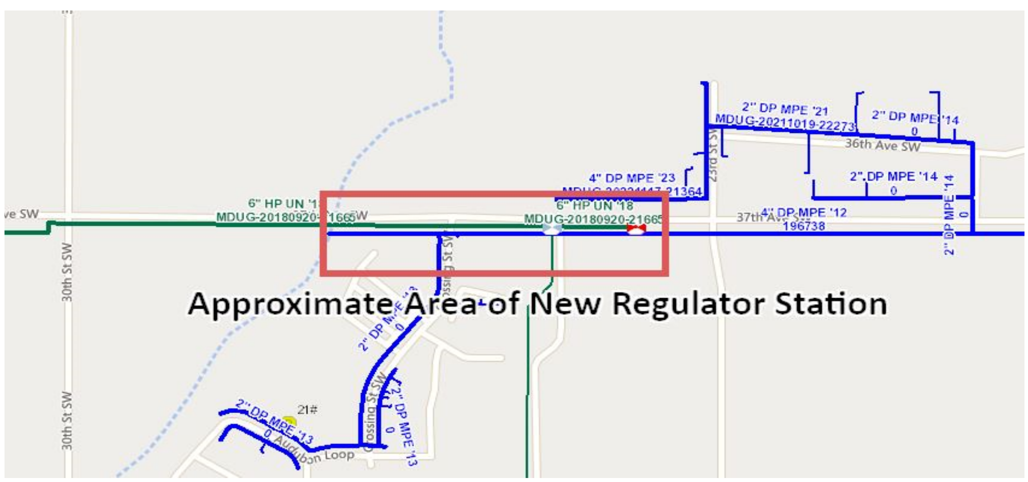
MAJOR CAPITAL PROJECTS

Minot Reinforcement Project

Q. Please describe the Minot Reinforcement Project.

A. The Minot Reinforcement project consists of two parts. The first is installation of 4-inch polyethylene (PE) pipe along 54th Ave SE and 27th St SE between Hwy 83 and Hwy 52. The second is the installation of a pressure regulator station along 37th Ave SW between 23rd St. SW and 30th St. SW.





Q. Why did the Company undertake the Minot Reinforcement Project?

A. The area along 54th Ave SE and 27th St SE has been identified as a constrained area of Montana-Dakota's system by local personnel. The 4-inch pipeline will help Montana-Dakota maintain reliable service in the area by eliminating local pressure constrains and allowing for additional orderly growth in the area. System modeling of this area's design day scenario showed that the southern sections of Minot would experience lower than desired pressures with its current core load and would only become more strained with additional core growth. The addition of the regulator station on 37th Ave SW provides an additional source of gas into the distribution system giving Montana-Dakota the ability to provide sufficient capacity to the south side of Minot.

Q. What work has been performed in prior phases of the Project?

A. This is scheduled to take place during a one-year time period.

Q. What is the timing of the Project?

A. The project is scheduled to be started in the spring of 2024 and completed by the end of 2024.

Q. What were the capital cost estimates of the Project?

A. The capital cost estimate is $1,030,238 as shown in funding projects FP-321614 and FP-323865 as shown on Statement B, Schedule B-2, page 6.

Q. How will the Company's customers benefit from the Project?

A. This project also increases the reliability of Montana-Dakota's distribution system allowing us to provide consistent service to our current and future customers even during the highest demand scenarios.

An additional benefit of the project is the ability to provide natural gas to new potential growth areas of Minot.

Q. Did the Company consider alternative ways or timeframes to meet the need for this Project?

A. Yes, alternative pipeline routes and pressure regulation options were considered. These include but not limited to: replacement/upsizing existing pipelines and regulator stations, uprating existing distribution system to a higher maximum operating pressure, and alternate pipeline routes. These alternatives were not choses due to one or more of the following reasons: option did not gain desired results, option was not as cost effective as the final chosen option, or the route had constructability issues that would make the option less desirable.

Jamestown Town Border Station

Q. Please describe the Jamestown Town Border Station Project.

A. The Jamestown Town Border Station project consists of upgrading the existing interconnect facilities located on 37th St SE just east of Hwy 281. The current facilities' have equipment in place that limits the amount of gas that can be transferred to Montana-Dakota's distribution system. As discussed in the testimony of Mr. Shawn Nieuwsma, Montana-Dakota will take over pressure regulation and over-pressure protection from WBI Energy giving the Company more control over its system pressures.

Q. Why did the Company undertake the Jamestown Town Border Station Project?

A. Montana-Dakota's system modeling continues to show that the pressure on the South side of Jamestown is no longer sufficient to reliably meet customer needs on a design day. The TBS upgrade is needed to maintain system reliability for existing customers and potential new customer growth in the future.

Q. What work has been performed in prior phases of the Project?

A. Design work on the new facility started in 2023.

Q. What is the timing of the Project?

A. The project started design work in 2023 and with construction, to be completed in 2024.

Q. What were the capital cost estimates of the Project?

A. The capital cost estimate is $1,565,103 as shown in funding projects FP-320160 and FP-323712 as shown on Statement B, Schedule B-2, pages 6 and 8, respectively.

Q. How will the Company's customers benefit from the Project?

A. The benefit of this project is the ability to provide sufficient natural gas capacity and pressure to the south end of Jamestown and increased reliability on the Jamestown distribution system.

Q. Did the Company consider alternative ways or timeframes to meet the need for this Project?

A. Yes, alternative pipeline routes and pressure regulation options were considered. These include but not limited to: replacement/upsizing existing pipelines and installation of a new town border station closer to North Dakota State Hospital and uprating existing distribution system to a higher maximum operating pressure. These alternatives were not choses due to one or more of the following reasons: option did not gain desired results, option was not as cost effective as the final chosen option, or the option was too complicated and difficult to implement and might have caused other issues to the system that would then need to be eliminated.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony

Of

Jesse Volk

Q. Please state your name and business address.

A. My name is Jesse Volk, and my business address is 705 West Fir Avenue, Fergus Falls, Minnesota 56537.

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

A. I am the System Integrity Manager for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade"), and Intermountain Gas Company ("Intermountain").

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

A. I am responsible for the management of the Transmission and Distribution Integrity Management programs and Integrity Replacement projects, which include the System Safety and Integrity Program (SSIP).

Q. Please outline your educational and professional background.

A. I am a graduate of South Dakota School of Mines and Technology with a Bachelor of Science Degree in Civil Engineering. I am also a registered professional engineer with the State of North Dakota.

I began my career in 2007 as a gas engineer with Montana-Dakota in Dickinson, North Dakota. Since that time, I have held various positions of increasing responsibilities throughout the gas operations and engineering departments across the eight states of Idaho, Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington, and Wyoming.

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

A. Yes, I have testified before the Minnesota and South Dakota Public Utilities Commissions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's System Safety and Integrity Program (SSIP); and (2) provide an overview of the Company's SSIP projects that were completed since the last rate case and those currently in progress.

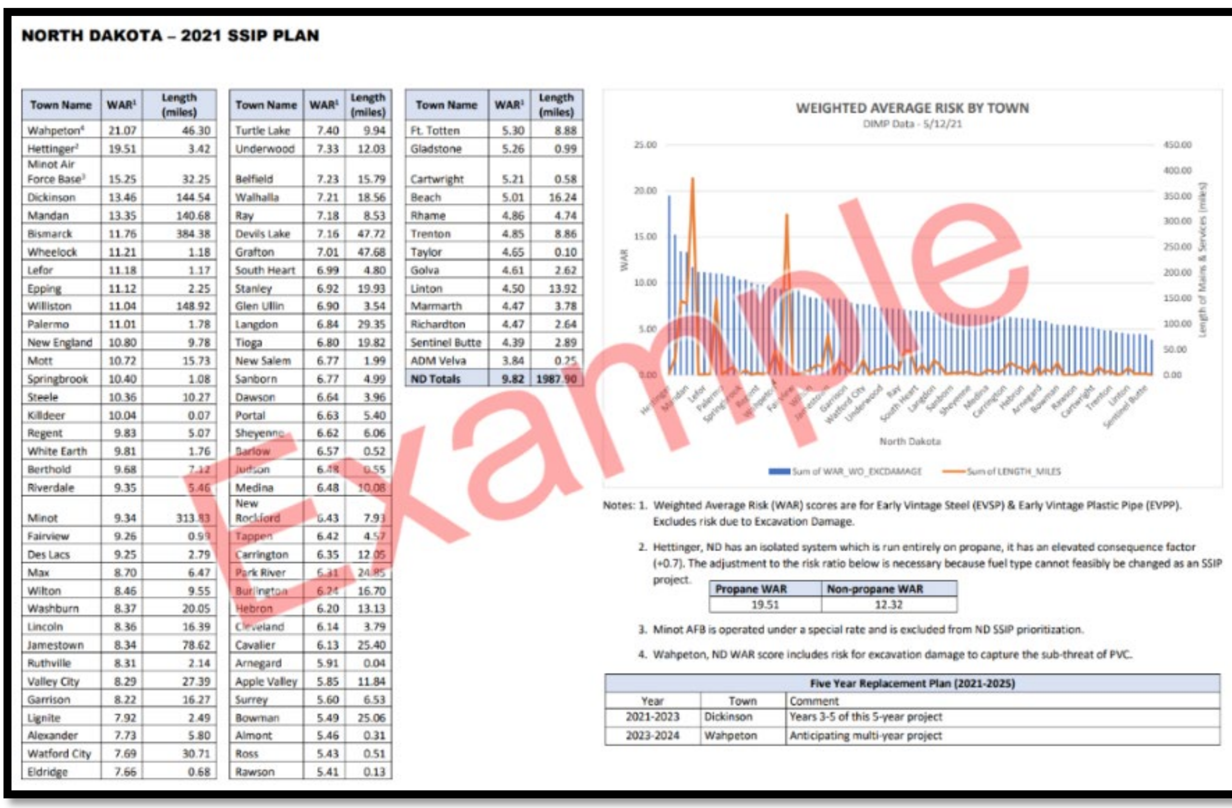
<u>OVERVIEW OF SYSTEM SAFETY AND INTEGRITY PROGRAM</u>

Q. What is Montana-Dakota's System Safety and Integrity Program (SSIP)?

A. Montana-Dakota's SSIP is a pipeline replacement program that accounts for a substantial portion of the Company's natural gas distribution capital investment. The replacements are a direct result of the Integrity Management Program (IMP) mandated by the Pipeline and Hazardous Materials Safety Administration (PHMSA). IMP requires pipeline operators to implement a comprehensive and cost-effective process that analyzes pipelines through all stages, including engineering, design, construction, operation, inspection, repairs, and replacement.

Q. How does the Company prioritize and select safety-related projects?

A. Montana-Dakota's Distribution Integrity Management Program (DIMP) assigns weightings and consequence factors to each pipeline segment based on attributes and key IMP threats. The data is analyzed through the System Safety Integrity Program (SSIP) which identifies and prioritizes Montana-Dakota's highest risk systems by state, based on the Weighted Average Risk (WAR) scores of Early Vintage Steel Pipe (EVSP) and Early Vintage Plastic Pipe (EVPP) as shown in Figure 1.



NORTH DAKOTA – 2021 SSIP PLAN

Town Name	WAR[1]	Length (miles)
Wahpeton[4]	21.07	46.30
Hettinger[2]	19.51	3.42
Minot Air Force Base[3]	15.25	32.25
Dickinson	13.46	144.54
Mandan	13.35	140.68
Bismarck	11.76	384.38
Wheelock	11.21	1.18
Lefor	11.18	1.17
Epping	11.12	2.25
Williston	11.04	148.92
Palermo	11.01	1.78
New England	10.80	9.78
Mott	10.72	15.73
Springbrook	10.40	1.08
Steele	10.36	10.27
Killdeer	10.04	0.07
Regent	9.83	5.07
White Earth	9.81	1.76
Berthold	9.68	7.12
Riverdale	9.35	5.46
Minot	9.34	313.83
Fairview	9.26	0.99
Des Lacs	9.25	2.79
Max	8.70	6.47
Wilton	8.46	9.55
Washburn	8.37	20.05
Lincoln	8.36	16.39
Jamestown	8.34	78.62
Ruthville	8.31	2.14
Valley City	8.29	27.39
Garrison	8.22	16.27
Lignite	7.92	2.49
Alexander	7.73	5.80
Watford City	7.69	30.71
Eldridge	7.66	0.68

Town Name	WAR[1]	Length (miles)
Turtle Lake	7.40	9.94
Underwood	7.33	12.03
Belfield	7.23	15.79
Walhalla	7.21	18.56
Ray	7.18	8.53
Devils Lake	7.16	47.72
Grafton	7.01	47.68
South Heart	6.99	4.80
Stanley	6.92	19.93
Glen Ullin	6.90	3.54
Langdon	6.84	29.35
Tioga	6.80	19.82
New Salem	6.77	1.99
Sanborn	6.77	4.99
Dawson	6.64	3.96
Portal	6.63	5.40
Sheyenne	6.62	6.06
Barlow	6.57	0.52
Judson	6.48	0.55
Medina	6.48	10.08
New Rockford	6.43	7.93
Tappen	6.42	4.57
Carrington	6.35	12.05
Park River	6.31	24.85
Burlington	6.24	16.70
Hebron	6.20	13.13
Cleveland	6.14	3.79
Cavalier	6.13	25.40
Arnegard	5.91	0.04
Apple Valley	5.85	11.84
Surrey	5.60	6.53
Bowman	5.49	25.06
Almont	5.46	0.31
Ross	5.43	0.51
Rawson	5.41	0.13

Town Name	WAR[1]	Length (miles)
Ft. Totten	5.30	8.88
Gladstone	5.26	0.99
Cartwright	5.21	0.58
Beach	5.01	16.24
Rhame	4.86	4.74
Trenton	4.85	8.86
Taylor	4.65	0.10
Golva	4.61	2.62
Linton	4.50	13.92
Marmarth	4.47	3.78
Richardton	4.47	2.64
Sentinel Butte	4.39	2.89
ADM Velva	3.84	0.25
ND Totals	**9.82**	**1987.90**

Notes: 1. Weighted Average Risk (WAR) scores are for Early Vintage Steel (EVSP) & Early Vintage Plastic Pipe (EVPP). Excludes risk due to Excavation Damage.

2. Hettinger, ND has an isolated system which is run entirely on propane, it has an elevated consequence factor (+0.7). The adjustment to the risk ratio below is necessary because fuel type cannot feasibly be changed as an SSIP project.

Propane WAR	Non-propane WAR
19.51	12.32

3. Minot AFB is operated under a special rate and is excluded from ND SSIP prioritization.

4. Wahpeton, ND WAR score includes risk for excavation damage to capture the sub-threat of PVC.

Five Year Replacement Plan (2021-2025)		
Year	Town	Comment
2021-2023	Dickinson	Years 3-5 of this 5-year project
2023-2024	Wahpeton	Anticipating multi-year project

Figure 1 - SSIP ND State Plan

Q. What types of projects are typically performed to address safety-related concerns?

A. Pipeline replacement is typically the most viable option to remediate risks associated with corrosion, material, weld/joint, equipment failure, incorrect operation, natural forces, outside forces, and missing data threats. If Montana-Dakota determines that replacement is an appropriate action to reduce the risk, the Company establishes a replacement project.

Q. Does the Company consider alternative ways or timeframes to meet the need for this project?

A. When feasible, Montana-Dakota works jointly with State, City, County, or general contractors performing highway, road, and underground infrastructure replacement projects within the same vicinity. This collaboration ultimately eliminates duplication of work, provides cost savings, and limits long-term interruptions to the public and Montana-Dakota's customers.

Q. How will the Company's customers benefit from the project?

A. Montana-Dakota's SSIP replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third-party damages. The Company's replacement of these high-risk systems ultimately increases overall public safety, lowers operating and maintenance (O&M) costs, and improves system reliability for Montana-Dakota's customers.

Q. Would you please describe the major capital projects that have been completed since the last rate case and the projects that are currently underway?

A. Yes. The following pages contain a description of each project, including the need for each project.

<u>MAJOR CAPITAL PROJECTS</u>

<u>Dickinson SSIP 2019 - 2023</u>

Q. Would you please describe the Dickinson SSIP project?

A. The Dickinson SSIP project is a multi-year project focusing on the replacement of Low Pressure EVSP and EVPP natural gas mains and services with medium and high-density polyethylene (MDPE & HDPE) lines. Project replacement quantities and type are as follows:

<u>Mains</u>

2" MDPE – 166,650 feet

4" MDPE – 72,961 feet

6" MDPE – 18,711 feet

4" Steel – 416 feet

12" HDPE – 6,343 feet

Totaling - 265,081 feet or 50.2 miles

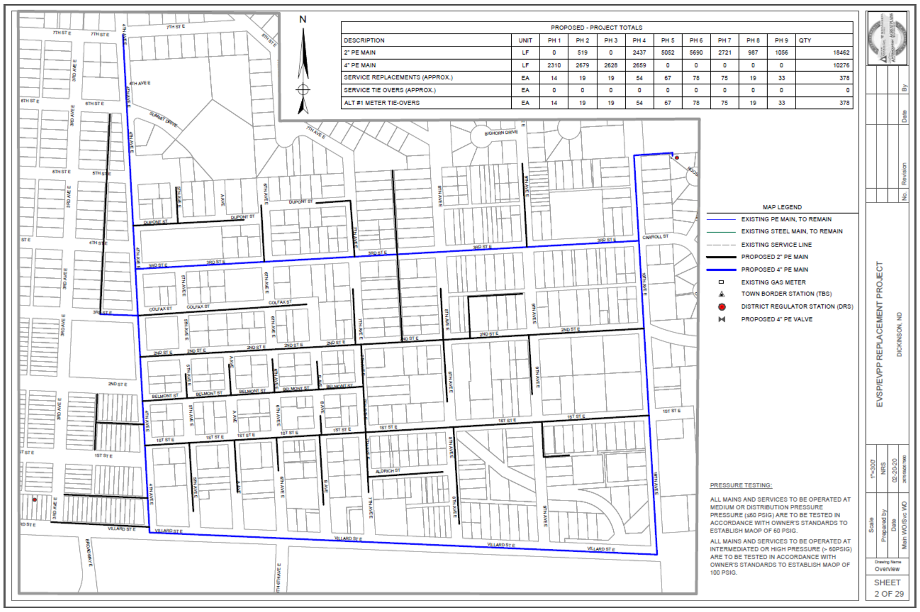
Services

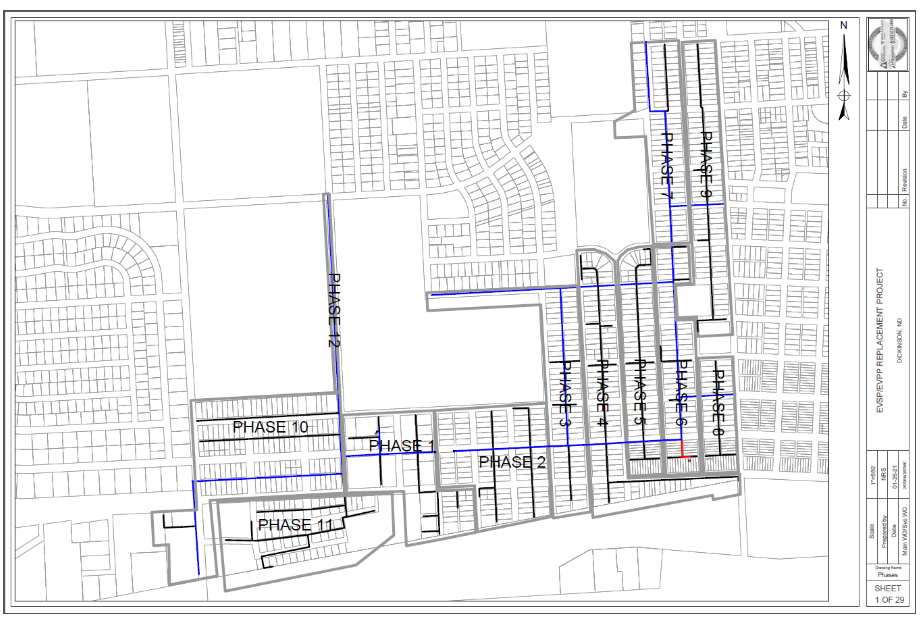
Service line quantity replaced or re-tested – 3,324

District Regulator Stations (DRS)

DRS Retired – 10

DRS Added/Replaced – 3





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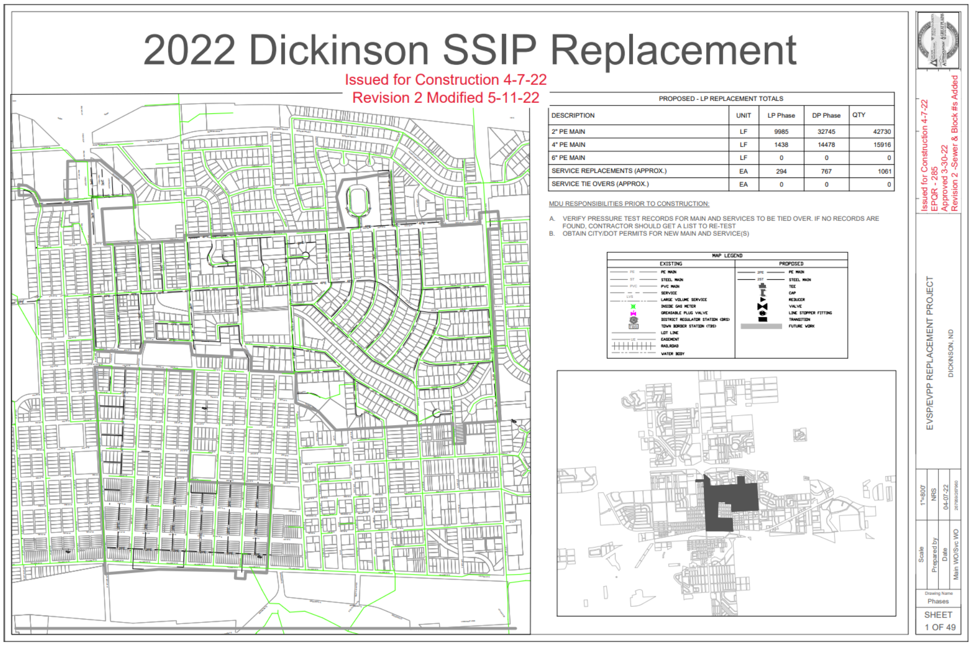
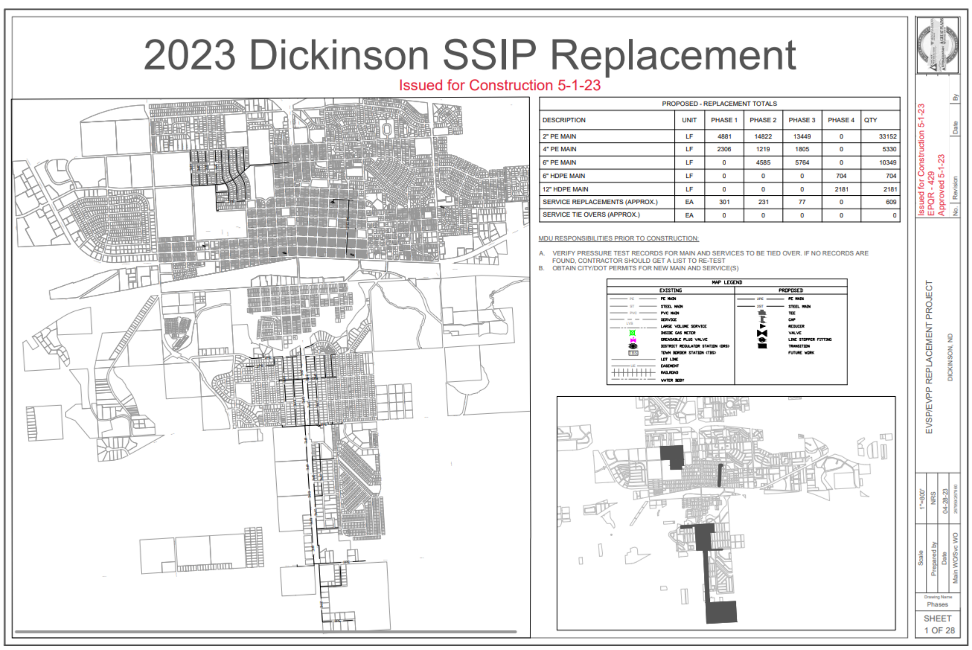


PROPOSED - LP REPLACEMENT TOTALS

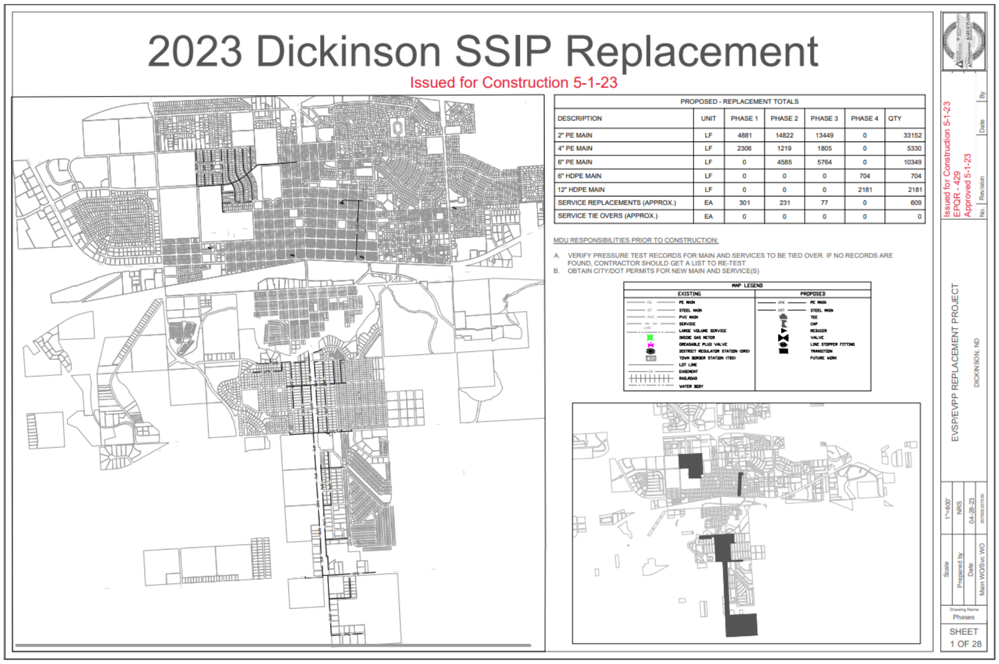
DESCRIPTION	UNIT	LP Phase	DP Phase	QTY
2" PE MAIN	LF	9985	32745	42730
4" PE MAIN	LF	1438	14478	15916
6" PE MAIN	LF	0	0	0
SERVICE REPLACEMENTS (APPROX.)	EA	294	767	1061
SERVICE TIE OVERS (APPROX.)	EA	0	0	0

2



PROPOSED - REPLACEMENT TOTALS

DESCRIPTION	UNIT	PHASE 1	PHASE 2	PHASE 3	PHASE 4	QTY
2" PE MAIN	LF	4881	14822	13449	0	33152
4" PE MAIN	LF	2306	1219	1805	0	5330
6" PE MAIN	LF	0	4585	5764	0	10349
6" HDPE MAIN	LF	0	0	0	704	704
12" HDPE MAIN	LF	0	0	0	2181	2181
SERVICE REPLACEMENTS (APPROX.)	EA	301	231	77	0	609
SERVICE TIE OVERS (APPROX.)	EA	0	0	0	0	0



Figure(s) 2-6 - Dickinson Yearly Plans

Q. Why did the Company undertake the Dickinson Replacement?

A. Dickinson was identified as Montana-Dakota's highest risk EVSP and EVPP natural gas system in the state of North Dakota in 2019 by the Company's SSIP.

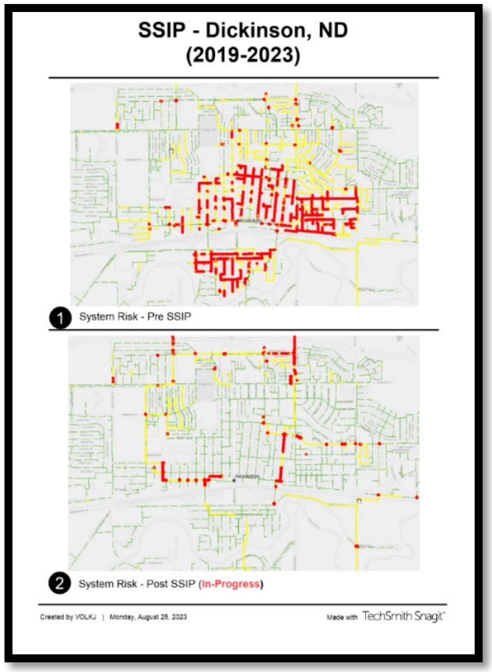


Figure 6 – Dickinson DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The current Dickinson SSIP project was started in 2019 and will be completed by the end of 2023.

Q. What are the costs of the project?

A. Project costs through August 2023 YTD are currently:

	2019	2020	2021	2022	08-2023 YTD	Grand Total
Main Replacements	$2,673,232	$3,939,110	$3,994,164	$4,881,115	$3,384,628	$18,872,249
Service Replacements	$1,296,415	$2,038,393	$2,950,185	$3,497,907	$1,834,724	$11,617,624

<u>Wahpeton SSIP 2022 – 2027 (Planned)</u>

Q. Would you please describe the Wahpeton SSIP project?

A. The Wahpeton SSIP project is currently replacing non-locatable

EVSP and EVPP (PVC) natural gas mains and services with medium density polyethylene (MDPE) line. Project replacement quantities and type are as follows:

Mains

2" MDPE – 9,107 feet

4" MDPE – 8,069 feet

6" MDPE – 754 feet

Totaling – 17,930 feet or 3.4 miles

Services

Service line quantity replaced or re-tested – 143

District Regulator Stations (DRS)

DRS Retired To-Date – 0

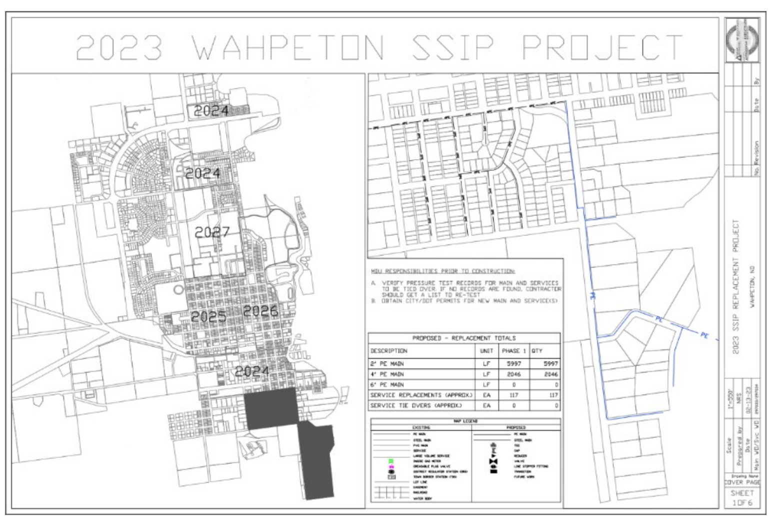


Figure 7 – Wahpeton

Q. Why did the Company undertake the Wahpeton Replacement?

A. Wahpeton was identified as Montana-Dakota's highest risk EVSP and EVPP natural gas distribution system in the state of North Dakota in

2021 according to the North Dakota state plan (Figure 1). Wahpeton is also the only remaining non-locatable PVC system in the Company's North Dakota service territory.

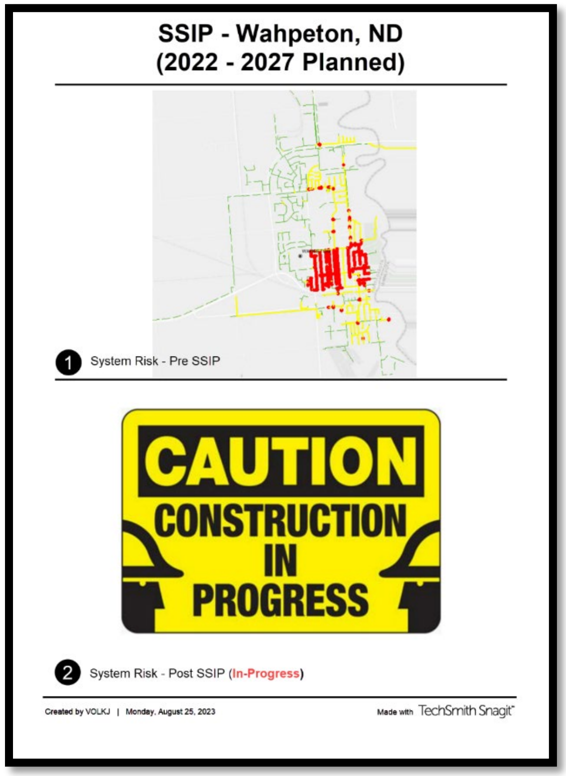


Figure 8 – Wahpeton DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Wahpeton SSIP project scope is a multi-year project starting in 2022 with an expected completion of 2027.

Q. What are the costs of the project?

A. Project costs through August 2023 YTD are currently:

	2022	08-2023 YTD	Grand Total
Main Replacements	$298,946	$279,471	$578,417
Service Replacements	$125,808	$175,344	$301,152

Q. Does the Company expect SSIP efforts to continue?

A. Pipeline operators have a requirement to implement IMPs that evolve and mature to fit an operator's unique operating environment. The evolution of an operator's IMP program takes time and resources to collect and analyze data to accurately identify the most current high-risk pipelines within any given system. Once a system is prioritized and selected it typically requires multiple years to develop and execute an action plan for full remediation or replacement.

Based on this information, Montana-Dakota expects the SSIP program to continue for the foreseeable future.

Q. What are the capital cost estimates of the project?

A. The current capital costs are $4,029,552 and $3,075,877 for 2023 as shown on Statement B, Schedule B-2, page 2. For 2024 the capital costs are $3,608,382 and $3,144,671 as shown on Statement B, Schedule B-2, page 6.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony

Of

Jeremy J. Ogden

Q. Please state your name and business address.

A. My name is Jeremy J. Ogden and my business address is 8113 West Grandridge Boulevard, Kennewick, Washington 99336.

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

A. I am the Director of Construction Services and Gas Measurement for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I have managerial responsibility for overseeing the day-to-day operations of the Company's construction management, welding, fusion and fabrication programs; maintenance for regulator stations, odorizers, and large volume meters; and the meter sampling and testing program.

Q. Please outline your educational and professional background.

A. I hold a bachelor's degree in civil engineering from Idaho State University and am a licensed Professional Engineer in Oregon and Washington. I have worked for Cascade Natural Gas and Montana-Dakota Utilities Co. for twelve years, previously as the Director of

Engineering Services, with the last five years managing the Construction Services and Gas Measurement departments for Montana-Dakota.

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

A. Yes, I have testified before the Washington Utilities and Transportation Commission.

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

A. I will provide support for the Company's North Dakota natural gas rate case application regarding the Company's purchase of gas meters, and the purchase of property for a new Construction Services shop in Bismarck, North Dakota.

<u>METERS</u>

Q. How does the Company determine how many meters to purchase?

A. The Company purchases enough meters each year to account for growth through new customers and to replace meters that have reached the end of their life cycle. The Resource Planning department performs an analysis to estimate the number of new customers and the Gas Measurement department's meter sampling and testing program can provide an estimate of the number of meters that will reach the end of their life cycle. Meter life cycles can be thirty, forty, or fifty years, depending on meter size.

Q. How many meters does the Company plan to purchase each year?

A. The Company purchases approximately ten thousand meters annually.

Q. How does the Company ensure that meters are functioning properly and providing accurate results?

A. The Company performs a statistical analysis each year on all meters that have been in service for ten years or more to determine the number of meters that need to be sampled. These meters are tested in accordance with Company's sampling and testing policy to ensure accuracy, and repairs and modifications are made as needed. Meters which cannot be repaired or modified to meet accuracy standards are removed from the system and disposed of. If a sample group fails to meet accuracy standards, then the entire group is replaced. Additionally, meters which have been in service for their life cycle are removed from the system, disposed of, and replaced with a newer meter.

Q. What is expected cost to purchase new meters?

A. The cost to purchase new meters, allocated to North Dakota Gas, is $3,094,720 for 2023 and $3,457,200 for 2024, as shown on Statement B, Schedule B-2, pages 2 and 6.

<u>CONSTRUCTION SERVICES SHOPS</u>

Q. What work is performed in the Construction Services shops?

A. Construction Services shops are used for fabrication of regulator stations, large volume meters, and other fabricated assemblies. Employees who perform fabrication also perform tapping and stopping of pipelines, and the shops are used to store specialized trucks and equipment for tapping and stopping.

Q. How does the Company determine where Construction Services shops are needed?

A. The Company locates Construction Services shops to provide tapping and stopping for construction projects which are complex and/or involve high pressure pipelines and facilities. These projects usually occur near the largest concentrations of customers. Shops are also located to provide secondary response in emergencies. The Company currently leases a shop in Bismarck, North Dakota and owns a shop in Billings, Montana.

Q. What alternatives to purchasing property and building a new shop are considered?

A. The Company began leasing a facility in Bismarck, North Dakota in November 2020, and recently renewed the three-year lease, which will expire in November 2026. Land for a new facility will allow the shop to be located closer to the Bismarck Service Center, which will result in more efficient use of Company resources, particularly inventory and parts ordering.

Q. What is the expected cost of the land for the Construction Services Shop?

A. The cost of the land for the Construction Services Shop, allocated to North Dakota Gas, is $503,950 as shown on Statement B, Schedule B-2, page 6 as FP-324957.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-___

Direct Testimony

Of

Darcy J. Neigum

Q. Please state your name and business address.

A. My name is Darcy J. Neigum 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 System Operations and Planning for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I have managerial responsibility for overseeing the day-to-day operations of the Company's electric control center and system operations and planning and communication engineering departments.

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 as well as a master's degree in Business Administration from the University of Mary. I have worked for Montana-Dakota Utilities Co. and the MDU Resource Group, Inc. for twenty-eight years with the last fifteen years managing the system operations & planning department for Montana-Dakota.

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

A. Yes, I have testified before this Commission, the Public Utilities Commission of South Dakota, the Public Service Commissions of Montana and Wyoming, and the Federal Energy Regulatory Commission.

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

A. I will provide support for the Company's North Dakota natural gas rate case application regarding the Company's two-way radio replacement project.

Q. Please describe the Company's existing two-way radio system.

A. Montana-Dakota and Great Plains Natural Gas have a two-way radio system which covers parts of five states serving both gas and electric customers. The current Montana-Dakota system was designed and built in the 1970's and 1980's and is comprised of 70 radio towers, 350 mobile users, 20 office base consoles and 30 remote handheld units. The current system is obsolete and operated through radio repeater towers which are linked together by telephone interconnect systems. Through the telephone interconnect system, users have to key or dial codes and telephone numbers to hop from repeater tower to repeater tower to communicate. This antiquated and very manual intensive communication system between towers creates challenges for timely and effective communication with employees in normal conditions and especially under emergency conditions. Certain employees may be working in different parts of the Company's service territory and are not familiar with the nearest radio repeater tower location or area radio frequency that is used to link the telephone interconnect systems.

Q. What type of replacement is the Company planning to make to its two-way radio system?

A. The Company is looking to install a new trunked 450 MHz radio system which allows users to move seamlessly across the Company's service territory and connect with other employees without the need for telephone interconnect equipment. This system design ensures ease of use and one to many radio conversations during routine operations as well as in emergencies. Another advancement in this system is that it can track the location of users of the two-way radio system for scheduling and emergency dispatching. The Company is working with Dakota Carrier Network to utilize their members' fiber optic network which eliminates the need for multiple new microwave hops to connect tower sites together. The Company is in the third year of engineering designs for the project and issued a request for proposal to vendors in late 2022 with installations to begin in 2024.

Q. What alternatives did the Company consider as part of its determination to replace its two-way radio system?

A. The alternative options that Company considered are:

1. Updating the existing radio system; and
2. Utilizing prioritized cellular communications like AT&T's First Net system.

Updating the Company's two-way radio system would still rely on the existing radio frequencies along with additional costs for newer repeater equipment and telephone interconnects. These updates do not resolve the issue that the system is difficult for employees to communicate with each other and does not lend itself to movement throughout the Company's service territory, thereby limiting its effectiveness during normal communications. The Company believes the effectiveness of updating the existing radio system would be further reduced during times of emergencies due to the limitations of accessing area repeater sites and the confines of sharing communications within a fixed area of radio coverage accessible only by an individual repeater tower.

Cellular and AT&T's First Net relies on commercial cellular towers and systems which can become overloaded in emergencies. During an emergency, 911 operators can instruct AT&T First Net to remove non-emergency personnel, like Montana-Dakota, from its prioritized network. The Company could be left in a situation where we cannot communicate during emergencies. Furthermore, cell towers currently have less range than two-way radio systems. This lack of coverage creates communication issues for the Company with its employees across various parts of our service territories, especially in rural areas.

Q. What is expected cost of the two-way radio upgrade project?

A. The cost of the two-way radio project, allocated to North Dakota Gas, is $2,064,357, as shown on Statement B, Schedule B-2, pages 7 and 8 as FP-316491 and FP-316128.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-___

Direct Testimony

Of

Eric P. Martuscelli

Q. Please state your name and business address.

A. My name is Eric P. Martuscelli, and my business address is 8113 West Grandridge Boulevard, Kennewick, Washington 99336.

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

A. I am the Vice President of Field Operations for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade"), and Intermountain Gas Company ("Intermountain"). Collectively, "MDU Utilities Group".

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

A. I provide executive leadership, direct, and coordinate activities for the entire gas and electric distribution field operations in the MDU Utilities Group service territory. I oversee delivery of regulated products and services and provide strategic direction to managers in implementing our organization’s programs, policies, and procedures.

Q. Please outline your educational and professional background.

A. I hold a Bachelor’s Degree in Organizational Management, in the Forbes School of Business, from Ashford University. I have been in the utility industry for nearly 31 years; 12 years in the field and 19 years in increasing levels of supervisory, managing, and leadership positions. Prior to advancing into my current role, I provided similar, executive oversight as Vice President, Operations for Cascade Natural Gas Corporation in Washington and Oregon.

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

A. Yes. I have previously presented testimony before the Washington Utilities and Transportation Commission and the North Dakota Public Service Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company’s mains and service lines growth and replacement capital projects. I will also provide testimony on the Company’s budgeted general tools capital expenditures.

<u>Growth & Replacement Projects</u>

Q1. How are Mains and Service Lines Growth and Replacement projects generally forecasted?

A. Growth and replacement capital projects are considered "blanket funding projects", meaning any single growth or replacement capital project, under $150,000 will be allocated to the blanket funding project, throughout any given plant addition year. Alternatively, any growth or replacement capital project estimated at $150,000 or above, is assigned to its own unique funding project and is not allocated to these blanket funding projects.

Q2. How are the project estimates formulated for blanket funding projects?

A. Mains and Service Lines growth capital project estimates, for these blanket growth funding projects, are budgeted and estimated in advance of the plant addition year. The estimates for the 2023 and 2024 blanket funding projects are derived from a combination of 2 years of actual expense, historical expense, and future year load growth forecasts.

Mains and Service Lines replacement capital project estimates, for these blanket replacement funding projects, are budgeted and estimated in advance of the plant addition year. Unlike growth capital projects, the estimates for these blanket funding projects are primarily derived from historical expense. Montana-Dakota anticipates, in any given year, that replacements of its facilities will be required, for a variety of reasons, including, but not limited to, damage, failure, or franchise/governing authority requirements. For the most part, these replacement capital projects can't always be anticipated so historical expense is estimated, and each subsequent years' funding project allocation is updated accordingly.

Q3. What are the costs of the projects?

A. The costs for the North Dakota Gas jurisdiction for Mains growth are $889,475 in 2023 and $1,021,244 in 2024 and are shown on Statement B, Schedule B-2, pages 2 and 6.

The costs for the North Dakota Gas jurisdiction for Mains replacement are $720,042 in 2023 and $1,434,735 in 2024 and are shown on Statement B, Schedule B-2, pages 2 and 6.

. The costs for the North Dakota Gas jurisdiction for Service Lines growth are $1,239,475 in 2023 and $1,466,454 in 2024 and are shown on Statement B, Schedule B-2, pages 2 and 6.

The costs for the North Dakota Gas jurisdiction for Service Lines replacement are $718,590 in 2023 and $1,382,607 in 2024 and are shown on Statement B, Schedule B-2, pages 2 and 6.

The increases in 2024 for mains and service lines replacement projects is primarily due to known and planned projects at approximately $1,100,000.

<u>GENERAL TOOLS</u>

Q1. Please describe the General Tools capital projects for North Dakota?

A. These capital projects comprise of standard tools and work equipment (assets), that are used to perform work in a safe, reliable, and qualified manner. Some assets simply reach their useful life and need to be replaced. Other assets are added to provide enhanced pipeline safety qualification training and to enhance pipeline safety compliance by utilizing new technology. Costs of these capital projects vary, from year to year, based on the age and condition of existing assets and organizational decisions on enhancement of both qualification training and pipeline safety compliance. An example is the addition of the new leak survey technology, in 2024, moving from traditional walking surveys to vehicle-based, mobile technology surveys increasing both safety and efficiency. This system is supported in the Direct Testimony of Mr. Micheal Schoepp.

The threshold for capitalization of any assets in this category is $1,000. Assets under $1,000 may be capitalized at the discretion of the Controller if the asset is part of a “set” or a large “project type purchase” totaling more than $1,000.

Q2. What are the costs of the projects?

A. The cost of the General Tools for North Dakota Gas jurisdiction is $335,474 in 2023 and $1,000,382 in 2024 as shown in Statement B, Schedule B-2, pages 3 and 7. The increase in 2024 is primarily due to the Picarro Leak Surveying Equipment at approximately $532,000 as shown in Statement B, Schedule B-2, page 7 and is supported in the Direct Testimony of Mr. Micheal Schoepp.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-23-___

PREPARED DIRECT TESTIMONY OF

LARRY E. KENNEDY

Q1. Please state your name and business address.

A1. My name is Larry E. Kennedy. My business address is 200 Rivercrest Drive SE, Suite 277, Calgary, Alberta, T2C 2X5.

Q2. .By whom are you employed?

A2. I am employed by Concentric Advisors, ULC

Q3. What is your position with Concentric Advisors, ULC. ("Concentric")?

A3. I am employed by Concentric as a Senior Vice President.

Q4. On whose behalf are you submitting this Direct Testimony?

A4. I am submitting this Direct Testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("MDU" or the "Company"). Specifically, this testimony, on behalf of MDU, refers to the gas utility and Common assets.

Q5. Please describe your education and experience.

A5. I am a Certified Depreciation Professional, with over 40 years of regulatory plant accounting and depreciation experience, and 22 years of depreciation and plant accounting consulting to the regulated utility industry. I have advised numerous energy and utility clients on a wide range of accounting, property tax and utility depreciation matters. Many of these assignments have included the determination of the cost of appropriate annual depreciation accrual rates. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No. LEK-2.

Q6. Please describe Concentric's activities in energy and utility engagements.

A6. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition, and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q7. Have you testified before any regulatory authorities?

A7. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No. LEK-2

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q8. What is the purpose of your Direct Testimony?

A8. The purpose of my Direct Testimony is to set forth the results of my full and comprehensive depreciation study of the Gas and Common plant in service MDU, as of December 31, 2021. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-3, titled "Calculated Annual Depreciation Rates Applicable to Gas Plant in Service as of December 31, 2021". Also, my detailed common report, including my analyses and recommendations, is provided in Exhibit No. LEK-4, titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021". The detailed depreciation study reports were prepared by me or under my direction.

Q9. Please provide a brief overview of the analyses that led to your depreciation recommendations.

A9. In preparing the depreciation study report, I analyzed the historic plant account data of MDU to prepare an analysis of the Company's past retirement experience. I met (virtually) with the Company's management and operations representatives to determine the extent to which the historic indications would be reflective of the future retirement patterns. Lastly, I also reviewed the average service life and net salvage indications of many North American based gas utilities to test the results of my analysis against the natural gas industry peers.

Q10. How is the remainder of your Direct Testimony organized?

A10. Section II provides the scope of my study and a summary of my analyses and conclusions. This section also includes a discussion of the major causes of changes in the depreciation accrual rate and amounts as compared to the last study. Section III provides a background on utility depreciation, depreciation methods and procedures. Section IV provides concluding comments.

II. SCOPE OF THE DEPRECIATION STUDY

Q11. Please outline the Scope of the Depreciation Study.

A11. My depreciation study report sets forth the results of the depreciation study for the gas distribution, and general plant assets of the MDU Gas Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the Average Life Group Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU gas assets in service, as of December 31, 2021.

Q12. Please outline the information included in your depreciation study report.

A12. The depreciation study report is presented in nine (9) sections outlined as follows:

Section 1 Study Highlights, presents a summary of the depreciation study and results.

Section 2 Introduction, contains statements with respect to the plan and the basis of the study.

Section 3 Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.

Section 4 Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation.

Section 5 Result of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 2, 3, 4, 5, and 6.

Section 6 Retirement Rate Analysis

Section 7 Net Salvage Calculations

Section 8 Detailed Depreciation Calculations

Section 9 Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis.

Q13. Was the depreciation study prepared using generally accepted standard methods and practices?

A13. Yes. Previous depreciation studies completed for MDU utilized a widely accepted method for the study of the Company's historic data, known as the Retirement Rate Analysis Method. The Retirement Rate Analysis Method is generally accepted as the correct method to use when aged data is available for review. The aged data used in the last study, through December 31, 2015, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2016 through to December 31, 2021, was provided by the

Company and incorporated in our database. Given the availability of reliable aged data, I prepared the historic study of mortality history using the retirement rate method. A detailed discussion of the retirement rate analysis is presented in Section 9 of my depreciation study report.

Additionally, the service life study included:

- **a review of MDU company practice and outlook, as they relate to plant operation and retirement;**

- **consideration of current practice in the gas system industry, including knowledge of service life estimates used for other gas system companies; and**

- **informed professional judgment which incorporated analyses of all of the above factors.**

My study of the net salvage percentages was based on detailed study prepared under the standard approach, which has commonly become known as the "Traditional method". Within this method, the net salvage transactions (gross salvage proceeds, re-use salvage and costs of removal or retirement) are compared to the original cost of the item being retired. The analysis is prepared on an actual transaction year basis, for as many years as reliable data is available. The analysis then includes a series of 3-year rolling average bands, 5-year rolling average bands, and life to date bands covering all years of transactional data.

As described in later sections of this evidence, the depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation.

The methods described above are generally accepted for use in the development of depreciation rates for regulated utilities.

Q14. Please provide a summary of the results of the depreciation study.

A14. The study results in an annual depreciation expense accrual related to the recovery of original cost (i.e. excluding net salvage requirement) of $22.6 million, when applied to depreciable plant balances, as of December 31, 2021. The study results are summarized at an aggregate functional group level as follows:

Summary of Original Cost, Accrual Percentages and Amounts

Plant Group	Original Cost	Annual Accrual	
Distribution Plant	$548,934,689	3.21%	$17,637,857
General Plant	$49,954,953	9.87%	$4,931,463
Total Plant in Service	$598,889,642	3.77%	$22,569,320

Q15. How do the above depreciation rates compare to the currently approved depreciation rates?

A15. The following chart summarizes the proposed composite depreciation rates as compared to the currently applied for composite depreciation rates.

Plant Group	Proposed Depreciation Rate	Currently Applied Depreciation Rate
Distribution Plant	3.21%	4.15%
General Plant	9.87%	5.08%
Total Plant in Service	3.77%	4.23%

Q16. Please outline the reasons for the decreased composite depreciation rate for the gas distribution assets.

A16. In the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that was lesser than the decline caused by the influence of the decreases due to the life extensions in many accounts. The following is a summary of the proposed average service life estimates compared to the currently used estimates, demonstrating the lengthening of the average service lives in three accounts.

Account	**Description**	**Proposed Iowa Curves**	**Current Iowa Curves**
374.2	Rights of Way	65-R3	65-R3
375.0	Distr. Meas & Reg Station Structures	55-R3	60-R3
376.0	Mains	55-R3	40-R3 to 62-R3
378.0	Meas & Reg Station Equip-General	50-R2	50-R2
379.0	Meas & Reg Station Equip-General	45-R2.5	45-R2.5
380.0	Services	50-R2.5	38-R0.5 to 47-R4
381.0	Meter & Meter Installations	31-R3	31-R3
383.0	House Regulators	58-R2.5	60-R3
385.0	Industrial Meas. & Reg. Station Equip	40-R2	40-R4
386.1	Misc. Property on Customer Premises	15-R3	15-R3
387.2	Other Equipment	30-R3	25-R3

The specific reasons for the average service life extensions for each of the large distribution accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical mortality study are presented for each account, in Section 6 of my report.

Q17. Are the average service life extensions, as noted above, typical for gas distribution assets?

A17. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of gas distribution assets is lengthening throughout North America. While there are a number of factors causing this lengthening of life estimates, the most prevalent reason is the increased focus of utilities in maintaining and life extending the distribution infrastructure. For example, in recent years gas distribution utilities have been pro-active in services structure management and adding enhanced pipeline quality in the type of product used for services.

Likewise, I have noted that the life of distribution assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by gas distribution utilities. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other gas utilities.

Q18. Please provide a summary of the current and proposed net salvage percentages for distribution plant.

A18. The following is a summary of the proposed net salvage percentages used in the depreciation rate calculations. I note that the current rates differ in many accounts from those proposed in the 2015 depreciation study. It is my understanding that the currently approved depreciation rates related to cost of removal were ultimately negotiated. Therefore, the net salvage percentage comparisons as noted below are based on the percentages as recommended in the 2015 depreciation study.

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
374.2	Rights of Way	0%	-0.02%	0%	0.00% 0.02%
375.0	Distr. Meas & Reg Station Structures	0%	-0.56%	(50)%	1.09% 0.28%
376.0	Mains	(55)%	1.19%	(50)%	1.17% 0.50%
378.0	Meas & Reg Station Equip-General	(30)%	0.60%	(30)%	0.66% 0.66%
379.0	Meas & Reg Station Equip-General	(5)%	0.07%	(15)%	0.37% 0.37%
380.0	Services	(100)%	1.18%	(200)%	4.83% 4.13%
381.0	Meter & Meter Installations	(20)%	1.74%	(20)%	0.96% 0.24%
383.0	House Regulators	(5)%	0.13%	0%	0.00% 0.00%
385.0	Industrial Meas. & Reg. Station Equip	(10)%	0.21%	(15)%	0.66% 0.66%
386.1	Misc. Property on Customer Premises	0%	0%	0%	0.00% 0.00%
387.2	Other Equipment	0%	0%	0%	0.01% 0.00%

(*)Rates identified in yellow represent the depreciation rate after negotiated settlement.

As noted above, the depreciation rates related to cost of removal and salvage currently used were changed significantly from the depreciation rates as proposed in the 2015 depreciation study. The current study has noted the continued trend to increased levels of recovery for cost of removal.

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q19. Is the trend for more negative net salvage percentage, as noted above, typical for gas distribution assets?

A19. Yes. The increased amount of cost of removal expenditures is a common trend throughout North American utilities. In fact, this trend has been the most significant change noted in depreciation studies over the past five years. Accordingly, it has become the most debated topic of depreciation studies filed throughout North America, as well as being a significant topic of discussion at depreciation conferences. At the Society of Depreciation Professionals conference held in September 2018, there were four presentations regarding the large increase in cost of removal expenditures. This trend has been witnessed over virtually all electric, gas and pipeline utilities. As such, the trend witnessed in my MDU study is consistent with depreciation studies conducted across North America.

Q20. What is causing this trend to increased cost of removal of utility assets?

A20. It is generally accepted that there exist three main causes of increases.

Firstly, as the average age of utility assets continue to be extended, the impact of inflation becomes more pronounced. As the average service life has increased, the length of time between the original installation of the assets in some accounts and the estimated average time of retirement of the assets is getting longer. The net salvage percentage is calculated by dividing the costs to remove the asset in dollars of the time when the asset is removed by the original cost dollar of the time of installation. Given that the major component of cost of removal is labor, this increase in the life expectation, also results in an increased length of time that the labor associated with the removal is longer. To the extent that the average service lives for distribution assets have extended, the impact as described applies to a number of the MDU gas distribution accounts.

Secondly, the costs associated with the removal (or retirement) of utility assets must deal with increased environmental and regulatory requirements. For example, the costs related to the safe removal of existing infrastructure have greatly increased since the assets were originally installed. Additionally, the utilities are required to deal with the increased level of regulations within areas that are much more densely populated at the time of removal of the assets as compared to when the assets were originally placed into service. As distribution assets are often removed in municipal areas, the need to effectively deal with urban growth and density within the areas adds a significant cost to the removal of the assets that did not exist at the time of the original installation of the assets. When the assets were originally installed, the distribution assets were largely within greenfield developments, whereas now, when the assets are removed, the utility must deal with (for example) applications for road closures and re-routing, noise bylaws, and performing work within and around developed and landscaped yards.

Lastly, as utilities have implemented new and enhanced accounting systems, the ability to better track capital projects has improved the processes to track capital project costs more accurately. This provides the ability for direct charging labor associated to costs of removal specifically to cost of removal. Likewise, in circumstances where the utility uses an allocation of the total project costs to recognize that a portion of the capital project relates to the removal of assets, the advancements in the work order and plant accounting systems provide better information to allow the utility to better develop proper allocation factors.

Q21. Was a Common depreciation study also completed?

A21. Yes, a depreciation study was also conducted on the MDU Common assets. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-4, titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021".

Q22. Please provide a summary of the results of the Common depreciation study.

A22. The study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $4.3 million, when applied to depreciable plant balances, as of December 31, 2021. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
General Plant	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970
TOTAL	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970

III. DEPRECIATION METHODS AND PROCEDURES

Q23. How is depreciation defined for a rate regulated utility?

A23. <u>Depreciation defined</u> – "Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas 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”.[1] When considering the action of the elements, my average service life recommendations have considered large catastrophic events that have occurred and impacted the life estimates of utility assets across North America through our use of peer analysis. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, windstorms, large scale flooding, fires, actions of third parties and other natural forces of nature, and these forces of retirement should be included in the determination of the average service life.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric system utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line Method of depreciation, which was adopted for use in my study.

Q24. Please outline the depreciation methods and procedures used in your depreciation study.

1 Federal Energy Regulatory Commission, Part 201Defination 12.B (2020)

A24. The calculation of annual and accrued depreciation, based on the Straight-Line Method, requires the estimation of survivor curves and the selection of group depreciation procedures, as discussed below.

Depreciation Grouping Procedures - When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. In the determination of the depreciation rates in this study, the use of the Average Service Life Procedure has been continued.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and Average Life Group Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations. Amortization accounting has been continued in this study in a manner largely consistent with the prior study. The following is a summary of the proposed amortization periods compared to the currently used estimates, demonstrating the lengthening of the average service lives in two accounts.

Account	**Description**	**Proposed Amortization Period in Years**	**Current Amortization Period in Years***
391.1	Office Furniture & Equipment	15	15
391.3	Computer Equipment - PC	5	5
393.0	Stores Equipment	30	30
394.1	Tools, Shop, & Garage Equipment	20	18
394.3	Vehicle Maintenance Equipment	20	20

Account	Description	Proposed Amortization Period in Years	Current Amortization Period in Years*
395.0	Laboratory Equipment	20	20
397.1	Communication Equipment – Fixed Radios	15	15
397.2	Communication Equipment – Mobile Radios	15	15
397.3	General Telephone Communication Equipment	10	10
397.8	Network Equipment	5	5
398.0	Miscellaneous Equipment	25	20

***Year equivalent calculated based on rate after negotiated settlement.**

A detailed account by account analysis of the factors considered in the selection of my recommended average service life estimates is provided in Section 3.6 of my depreciation study report.

Q25. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A25. The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the Straight-Line Method, the Average Life Group Procedure was applied on a remaining life basis. However, I note that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintage approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a Calculated Accumulated Depreciation ("CAD") weighted calculation in the textbook Depreciation Systems, by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994, under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies were based on a broad averaging of the composite remaining life. This method is also discussed as the Amortization Method in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

In the manner in which I developed the remaining life calculations, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. Specifically, my calculations are made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole as compared to applying one overall composite life to all vintages as done in prior studies. My calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account. Consistent with the plant accounting systems of most utilities, MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. As such, the

accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates, and the achieved age of each vintage.

2. The estimated remaining life of each vintage within each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving, as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on a CAD approach to the remaining life calculations is widely considered to be the most accurate. I agree and view this methodology as the correct and most appropriate calculation.

IV. CONCLUDING REMARKS

Q26. What is your conclusion with respect to MDU's proposed Depreciation expense?

A26. My conclusion is that MDU's requested depreciation rates, resulting in a composite depreciation rate of 3.77% for the Gas Division and 5.31% for the Common Plant, reasonably reflects the annual consumption of the undepreciated service value of the utility plant in service. Therefore, the use of the depreciation rates as presented in my report, by account, will provide for an appropriate amount of depreciation expense in the Company's revenue requirement. Therefore, I recommend that the proposed depreciation rates set forth in the depreciation studies, that I prepared for this proceeding, be adopted by the Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q27. Does this conclude your Direct Testimony?

A27. Yes, it does.

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and

Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).
- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)
- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently

have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.
- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.
- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").
- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.
- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public

Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.
- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.
- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.
- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional

full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	United Illuminating Company	United Illuminating Company	Connecticut Public Utilities Regulatory Authority	22-08-08
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	Case No. PU-22-194
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	RP22-1033-0000
2023	Indiana American Water Company	Indiana American Water Company	Indiana Utility Regulatory Commission	Cause No. 45870
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	Public Service Commission of the State of Montana	2022.11.099
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	South Dakota Public Utilities Commission	NG23

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	Enbridge Gas Inc.	Enbridge Gas Inc.	Ontario Energy Board	EB-2022-0200
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243
2022	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	Manitoba Hydro 2023/24 & 2024/25 General Rate Application
2023	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	Application No. PNG NE2023 to 2024 RRA

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-____

Direct Testimony

Of

Larry D. Oswald

Q. Please state your name and business address.

A. My name is Larry D. Oswald, 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 Business Development & Energy Services for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I have managerial responsibility for overseeing the day-to-day operations of the Company's Business Development and Energy Services department which provides the economic analysis for all new customer growth projects.

Q. Please outline your educational and professional background.

A. I hold a Bachelor of Science degree in Energy Management, with a minor in Finance from Moorhead State University. I am also a Certified Energy Manager (CEM) and Certified Demand-Side Management (CDSM) professional with the Association of Energy Engineers (AEE). I have worked for Montana-Dakota for twenty-four years with the last 6 years managing the business development and energy services department for Montana-Dakota.

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

A. The purpose of my testimony is to provide support for the Company's capital investments in the new Wahpeton Town Border Station (TBS) and the associated high-pressure line, the expansion to the City of Kindred, the City of Portal distribution system, and service to the North Dakota Soybean Processors (NDSP) plant near Casselton North Dakota.

I will also provide testimony and support for the Company's system betterment investments in conjunction with new growth projects as required under Section 5 of the Company's Rate Gas Service Extension Policy 120.

Furthermore, I will be discussing the Company's communication plan for Wahpeton's conversion from service under the Great Plains Natural Gas Co.'s (Great Plains) natural gas tariff to service under Montana-Dakota's natural gas tariff and bill.

Finally, I will discuss the Company's plans for natural gas energy efficiency programs for residential and commercial customers.

<u>Wahpeton TBS and High-Pressure Line</u>

Q. Why is the WBI Energy Wahpeton transmission line needed?

A. Montana-Dakota, through its division Great Plains, has served the Wahpeton area with natural gas service for over 50 years. The area is served using Great Plains' existing transmission line which is approximately 66 miles in length and extends from an interconnection with the Viking Transmission line near Vergas, Minnesota to Breckenridge, Minnesota. The transmission line is eight (8) inch steel from Vergas to Fergus Falls and six (6) inch steel from Fergus Falls to Breckenridge. Montana-Dakota has seen growth over the years along its transmission line including in the Wahpeton area.

This growth has limited the amount of capacity available on the Great Plains transmission line in Minnesota and in the Wahpeton area on peak days. Montana-Dakota has had periodic discussions with interruptible customers and their desire for firm natural gas service for over ten years. Discussions on possible solutions increased around 2015 due to significant curtailments to interruptible customers during the 2014 polar vortex and also due to a potential large volume customer's interest in locating its operation in Wahpeton. This customer desired firm natural gas service and, due to the incremental costs to supply firm natural gas service and other factors, they chose to locate their operations in another location.

Montana-Dakota evaluated possible solutions again in 2018/2019 due to the City of Wahpeton's economic development efforts and an existing large industrial customer's desire to expand their operations. At that time however customer interest and commitment were not sufficient to move forward with a project.

Montana-Dakota continued to have conversations with the city of Wahpeton, Regional Economic Development Council, legislative representatives, legislative committees, state leaders, and existing large customers through-out 2019 and into early 2020. Montana-Dakota continued to evaluate the options and the WBI Wahpeton line continued to be the best option. In late 2020 Montana-Dakota elected to move forward with securing the required customer commitment for the WBI Wahpeton line project from our existing interruptible customers in Wahpeton. In December of 2020 Montana-Dakota received a letter of support from the Mayor of Wahpeton which was co-signed by several Regional Development Partners.

Sufficient customer commitment was obtained by mid-2021 which allowed Montana-Dakota to move forward executing the Precedent agreement with WBI for the Wahpeton transmission line.

Q. What role does WBI Energy play in the proposed expansion?

A. WBI Energy will be the owner & operator of the Wahpeton Transmission line up the high-pressure side of TBS.

Q. What other options did Montana-Dakota review to provide additional capacity to Wahpeton?

A. Montana-Dakota considered three alternatives to the WBI Wahpeton Line. The first option was a direct replacement of the existing 66-mile transmission line described above. The existing transmission line replacement was dismissed due the higher initial cost and difficulty of replacement due to all the lakes between Vergas and Fergus Falls, Minnesota.

The second alternative was a new interconnection with Viking Transmission near Hawley, Minnesota and then constructing a new approximately 60-mile distribution line to Breckenridge. This project was approximately the same distance as the WBI Mapleton to Wahpeton project, however the project was dismissed due to a projected higher initial cost which would therefore have a higher rate impact to all customers. The project cost was estimated to be higher primarily due to the new tap on Viking and the size of the pipeline. The higher pipeline size was driven by Montana-Dakota's desire to operate the line as distribution versus transmission. This project would also have had a lower future growth potential.

The third alternative considered upgrading our existing interconnection with Alliance Pipeline Company near Fairmont, North Dakota and constructing a new pipeline to Wahpeton. The new pipeline would have been approximately 23 miles in length. This option was the lowest initial cost option, however, was dismissed for the following reasons:

- Higher rate impact to Wahpeton customers.
- Long-term commodity cost increases due to Aux Sable liquids charges and Chicago versus Ventura index pricing.
- Gas supply for Wahpeton would not have been connected to Montana-Dakota's integrated system with access to storage.
- Montana-Dakota has no owned upstream capacity on Alliance and therefore would have had to commit to additional capacity or purchase from marketers.

Q. Has WBI received FERC approval for the Wahpeton line?

A. Yes, the Federal Energy Regulatory Commission granted approval on October 19, 2023. WBI will be acquiring the easements and materials this year.

Q. What additional infrastructure is required to connect the WBI Energy transmission line to the existing Wahpeton distribution system?

A. As part of the construction of the WBI Energy transmission line, WBI Energy will provide a tap and high-pressure measurement for a new TBS to serve Wahpeton. Montana-Dakota is required to construct the downstream side of the TBS which will include regulation, relief, and a line heater at an estimated cost of $693,000. The planned location of the new TBS will also require construction of approximately 6,600 feet of twelve-inch (12) high pressure steel line to tie into the existing high-pressure line that serves the Wahpeton distribution system. The estimated cost of the twelve (12) inch steel line is $2,147,900.

Q. Will the Wahpeton distribution system still be connected to the Great Plains transmission line in Minnesota?

A. Yes, the connection with the Great Plains transmission line at the Breckenridge TBS will be maintained for reliability and redundancy, however under normal operations gas will only flow into the Wahpeton distribution system from the new WBI Energy transmission line.

Q. What are the benefits to Wahpeton Customers because of this project?

A. There are several benefits to Wahpeton customers because of this project. Currently Wahpeton customers are part of the Great Plains integrated gas system, which has operated independent of Montana-Dakota's integrated system. With the new WBI Energy connection, Wahpeton can be served through Montana-Dakota's integrated gas system which provides additional access to storage and production supplies.

Additionally, Wahpeton customers will benefit from the increased reliability of supply by maintaining the existing connection with the Great Plains transmission line in the case of system emergencies.

Lastly, Wahpeton and all North Dakota customers may benefit from additional customer and load growth in the Wahpeton area due to the availability of firm natural gas supply.

Q. Has Montana-Dakota had any communication with Wahpeton customers regarding the WBI expansion project and opportunities that may be available to them once the expansion project is complete?

A. Yes, Montana-Dakota contacted all but one of the Wahpeton interruptible customers to obtain a Firm Service Commitment Letter agreement. The only customer that was not contacted was a grain dryer and Montana-Dakota only provides interruptible service to grain dryers due to their highly variable load.

All but two interruptible customers contacted signed the Firm Service Commitment Letter, which requires them the to take firm natural gas service for all existing and future gas requirements for a period of ten years from the in-service date WBI Wahpeton Line. The customers have the option of taking service under Montana-Dakota's Firm General Contacted Demand Rate 74 or Firm General Service Rate 70.

Q. What are the capital cost estimates of the project?

A. The current capital cost is $2,147,900 as shown as FP-321768 and $693,000 as shown as FP-321769, both on Statement B, Schedule B-2, page 6.

Q. Has the WBI Wahpeton Line provided any other opportunities for growth?

A. Yes, Montana-Dakota has filed for and received a service area agreement to serve the City of Kindred. The distribution costs will require a separate surcharge, so no additional capital expenditures have been included in this filing. However, the Company has included Kindred customers and volumes in this filing.

<u>City of Portal Distribution System</u>

Q. Does Montana-Dakota already serve the City of Portal with natural gas?

A. No, Portal, North Dakota would be a new community that is served natural gas by Montana-Dakota. Montana-Dakota does provide electric service to the city of Portal. Montana-Dakota and the City of Portal executed a natural gas Franchise Agreement dated February 7th, 2023.

Q. Does the city of Portal already have natural gas service?

A. Yes, the City of Portal and the Port of Entry, Burke County, North Dakota, currently receive natural gas service through a municipal natural gas distribution system owned by the City of Portal. The City of Portal currently provides service to 70 customers, which includes the five (5) Port of Entry accounts. The City of Portal's gas supply is currently supplied through a gas purchase agreement with SaskEnergy Incorporated (SaskEnergy). The City of Portal also has created the Portal Municipal Gas Company of Canada (PMGC) for their Canadian Pipeline that interconnects with SaskEnergy on the Canadian side of the border. PMGC has a Pipeline Services Agreement with SaskEnergy to operate the pipeline.

SaskEnergy informed the City of Portal that if they wanted to continue with their current Pipeline Services Agreement, SaskEnergy would require additional insurance coverage. The City of Portal determined that the additional insurance necessary to meet SaskEnergy's requirements was not affordable and therefore would have to discontinue service with SaskEnergy. Notice was provided to the City that the agreement would end in April 2023; however, the City of Portal worked with SaskEnergy to extend the agreement until the new system is placed into service.

Montana-Dakota entered into a contract with the City of Portal to provide O&M for their gas distribution system within the city and their pipelines on the United States side of the border until such time as the updated system is placed into service. The City of Portal's current distribution system is unlocatable and therefore Montana-Dakota was not interested in purchasing the system and the current Portal distribution system will be decommissioned as part of this project. Decommissioning costs will be paid for by the City of Portal under the O&M Agreement.

Q. Did Montana-Dakota request, and receive, a Certificate of Public Convenience & Necessity (CPCN) from the North Dakota Public Service Commission to serve the City of Portal?

A. Yes. On May 3, 2023, Montana-Dakota submitted an application with this Commission for a CPCN to construct and operate natural gas distribution facilities to serve the City of Portal.

On June 28, 2023, the Commission granted Montana-Dakota Certificate Number 5977 to serve the City of Portal.

Q. Is this extension of natural gas service to the City of Portal cost justified under Montana-Dakota's currently effective extension tariff?

A. No, this extension will require a contribution in aid of construction (CIAC) by the City of Portal. The CIAC is estimated to be $634,468 and will cover all costs for the WBI Energy transmission tap, regulator station, and distribution mains to serve the City of Portal. The project will be trued up to actual costs once construction is complete.

Montana-Dakota has calculated our Maximum allowable Investment (MAI) under the currently effective Natural Gas Extension Tariff Rate 120 to be $243,752 and is sufficient to cover the remaining costs for the service lines to serve the 70 existing customer that are currently connected to the City of Portal's distribution system.

Q. How does the city of Portal plan to pay for the required contribution in aid of construction?

A. The City of Portal has applied for and received preliminary approval for a Community Block Grant (CBG) through the North Dakota Department of Commerce. The City of Portal is expecting final award in late 2023.

The City of Portal will use the CBG Grant to pay for the CIAC required for Montana-Dakota to construct the project.

Q. Will the City of Portal's current residential and commercial customers see a savings on their natural gas costs under Montana-Dakota's rates?

A. Yes, both residential and commercial customers are expected to see a saving under Montana-Dakota's rates versus the current City of Portal rates. The savings for the average residential customer is $409 annually, the average small commercial customer is $345, and large commercial is $2,713. The analysis is based on Montana-Dakota's currently effective tariffs and the three-year average of Montana-Dakota's cost of gas.

Q. When does Montana-Dakota plan to begin and complete construction of the new distribution system?

A. Montana-Dakota plans to begin construction in the Spring of 2024 and complete construction and place all customers into service by the Fall of 2024.

Q. What are the capital cost estimates of the project?

A. The current capital cost, exclusive of the CIAC, is $59,830 as shown as FP-324934, $33,775 as shown as FP-324937, and $143,599 as shown as FP-324933, all on Statement B, Schedule B-2, page 6 and $1,975 as shown as FP-324940 on Statement B, Schedule B-2, page 8.

<u>North Dakota Soybean Processing (NDSP) Plant</u>

Q. Can you describe the project and the facilities that will be installed to serve NDSP?

A. Montana-Dakota has entered into a natural gas extension agreement to provide firm natural gas service to NDSP. Montana-Dakota will be providing service to NDSP's facility through construction of a new tap of WBI Transmission line, new TBS, and approximately 10,700 feet of six-inch steel main to serve the customer located in Section 34 Township 140 N and Range 52 West in Cass County (west of Casselton, North Dakota).

The estimated investment associated with a tap on the WBI transmission line and construction of the pipeline and associated equipment necessary to delivery natural gas to the NDSP facility is estimated to be $3,190,797.

Q. Did Montana-Dakota request, and receive, a CPCN from the North Dakota Public Service Commission to serve NDSP?

A. Yes. On September 7, 2022, Montana-Dakota submitted an application with this Commission for a CPCN to construct and operate a natural gas distribution system to serve NDSP’s facility near Casselton.

On December 14, 2022, the Commission granted Montana-Dakota Certificate Number 5971 to serve NDSP’s facilities near Casselton.

Q. What rate schedule will NDSP be served under?

A. NDSP has requested temporary construction heat for the winter of 2023-2024 which will be served under Montana-Dakota's Firm General Service Rate 70. NDSP, upon plant start-up which is expected July 2024, will be served under Firm General Contracted Demand Service Rate 74 with a contract demand of 4,100 dk per day.

Q. Is this extension of natural gas service to NDSP cost justified under Montana-Dakota's currently effective extension tariff

A. Yes, the projected MAI under Firm General Contracted Demand Service Rate 74 is expected to be $3,199,038 which exceeds the estimated cost of the project by approximately $10,000.

Q. Did Montana-Dakota require NDSP to provide financial security for the project?

A. Yes, Montana-Dakota required NDSP to provide financial security for the estimated cost of project plus gross up for income taxes in the amount $3,654,420.

Q. Does Montana-Dakota's extension agreement with NDSP require a true-up to actual cost upon completion of construction?

A. Yes

Q. When does Montana-Dakota plan to complete construction of the facilities to serve NDSP?

A. Montana is currently working on the project and expects to place the distribution line to serve the facility into service by early November

2023 in order to serve NDSP with temporary construction heat for the winter of 2023-2024.

Montana-Dakota and WBI Energy will have additional work to complete at the TBS in the spring of 2024 to provide the permanent service required by NDSP. NDSP currently plans to start commissioning the plant in July of 2024.

Q. What are the capital cost estimates of the project?

A. The current capital cost is $1,649,143 as shown as FP-323578, $356,625 as shown as FP-323581, and $145,604 as shown as FP-323655, all on Statement B, Schedule B-2, page 2, and $954,882 as shown as FP-323583 on Statement B, Schedule B-2, page 4.

<u>Gas Service Extension Policy Rate 120 Section A5 – System Betterment</u>

Q. Did any customer main extension include system betterment projects since the last rate case?

A. Yes, there are three customer extension projects that also had the installation of facilities considered as system betterment associated with them.

Q. Can you provide a breakdown of each projects costs charged to the customer extension project and what the cost of the system betterment facilities were?

A. Yes, the table on the following page is a summary of the costs associated with each project:

Project	Type of System Betterment Description	Location	Estimated Project cost	System Betterment Cost	Customer MAI	Customer Contribution
Project A	4 inch to 6 Inch PE	Bismarck	$ 49,845	$ 12,229	$ 29,670	$ 7,946
Project B	System looping	Minot	$ 49,895	$ 28,239	$ 7,085	$ 14,571
Project C	System looping	Dickinson	$ 20,220	$ 979	$ 2,441	$ 16,800
		Total System Betterment cost		$ 41,447		

Q. Can you also provide the supporting details and justifications for each project?

A. Yes, Project A was to serve an expansion for an existing commercial customer. The existing two (2) inch PE main serving the customer was not large enough to provide service to the expansion and would require it to be replaced with approximately 700 feet of four (4) inch PE main. However, the Company's overall masterplan is to have a six (6) inch main line in this area so six (6) inch PE main was installed. The customer's economic analysis was based on the cost of the required four (4) inch PE main. The increased cost for installing the six (6) inch PE main was considered system betterment.

Project B was to serve new commercial facility in Minot which had a two (2) inch PE main bordering the property. However, this two (2) inch PE main is in an area of low pressure and would not support the commercial facilities natural gas requirements.

In reviewing options to provide service to the customer Montana-Dakota determined there was two options. The first option which had a lower initial cost was to extend off of a High Pressure (HP) line approximately 800 feet, however this option would also require a high-pressure meter set to serve the customer. The high-pressure meter and high-pressure line to serve this customer was not required in order to serve this customer and is something the Company tries to avoid from a safety perspective if the high pressure service is not required to serve the load.

The second option was to do some looping of the existing low-pressure system which based on system modeling would allow Montana-Dakota to provide service to this customer off the existing two (2) inch PE main adjacent to the property. The system looping along with a new district station was in Montana-Dakota's master plan for this area to address system pressure concerns. The looping project would also provide additional system reliability.

Montana-Dakota chose the second option as the looping was going to be required in the future. In addition, the Company could avoid a high-pressure service and metering which was not required to serve the customer requirements.

The customer's economic analysis was based on the cost of the high-pressure main and service as this would have provided the customer service at a lower initial cost.

Project C was to serve a new seventeen (17) lot residential subdivision in Dickinson. The project required 4,035 feet of two (2) inch PE main to serve all seventeen (17) lots within the new residential subdivision. Montana-Dakota determined that if the Company installed an additional 350 feet of two (2) inch PE main, that was not required to serve the new subdivision, Montana-Dakota could loop the existing distribution system which would provide additional system pressure support and reliability.

Montana-Dakota chose to install the additional 350 feet of two (2) inch PE main as the Company's cost to just continue at the time of the main extension would be less than looping the system later. The Customer's cost in the economic analysis did not include the cost of the additional 350 feet of two (2) inch PE main as it was considered system betterment and not required to provide the customer service.

Q. Do you feel the costs were appropriately assigned in accordance with Rate 120 Gas Service Extension Policy?

A. Yes, I do.

<u>Wahpeton Customer Integration Communication Plan</u>

Q. If the Commission approves the Company's proposal to integrate the Great Plains Wahpeton Tariff into Montana-Dakota's Gas Tariff, how does the Company plan to communicate this change with Wahpeton customers?

A. Montana-Dakota is proposing to use several outreach channels to ensure customers are informed about the changes and the impacts. Montana-Dakota plans to develop a webpage specifically for the conversion of Wahpeton to Montana-Dakota's Gas Tariff. The webpage will include the details and timing of the conversions, average customer impacts, a list of frequently asked questions, and contact information for individual assistance.

Montana-Dakota is also planning to set up open office hours in the Wahpeton area that will be staffed with Energy Services Representatives that can provide individualized assistance to customers to ensure customers understand how this conversion will impact their home or business.

Additionally, Montana-Dakota will utilize bill inserts and onserts, social media, and local media channels to encourage customers to visit the Company's website and advertise the open office hours.

Q. Does the Company currently have an office in Wahpeton?

A. The Company currently has a shop location in Breckenridge, Minnesota, however for the open office Montana-Dakota will look to lease office space the month prior to the conversion and for a month or two after the conversion in Wahpeton. Energy services staff will be available on a set schedule during the week with evening hours also available.

<u>Natural Gas Energy Efficiency Programs</u>

Q. Did Montana-Dakota develop a portfolio of natural gas energy efficiency programs for North Dakota customers?

A. Yes, Montana-Dakota developed a portfolio of cost-effective energy efficiency rebate programs for residential and commercial customers.

Q. Is Montana-Dakota proposing to implement the energy efficiency programs as part of the case?

A. No

Q. Why is Montana-Dakota not proposing to implement the energy efficiency programs?

A. Montana-Dakota has been in discussions with the North Dakota Department of Commerce State Energy Office regarding potential funding for statewide energy efficiency programs. The potential state funding is through the United States Department of Energy (DOE) as part of the Inflation Reduction Act (IRA). The IRA specifically includes two provisions together authorizing $8.8 billion in rebates. The first provision is for Home Energy Performance Based whole house rebates which includes Energy Star Rated natural gas equipment and the second is for High Efficiency Electric home rebates and will focus on electrification of home heating and water heating.

The IRA Home Energy Rebates are formula grants available to state energy offices. The North Data State Energy Office is planning to apply for the grants and may look to the energy utilities to administer the programs for their customers. Montana-Dakota's understanding is the North Dakota State Energy Office is working on a Request for Proposals (RFP) to design the state plan and then the next step would be an RFP for a program administrator.

Currently Montana-Dakota plans to continue working with the State Energy Office on the potential IRA funding to hopefully provide natural gas and electric rebates to North Dakota customers.

Q What happens If the funding through the North Dakota State Energy Office is not available or not sufficient for North Dakota natural gas customers?

A. Montana-Dakota would propose the portfolio of natural gas energy efficiency programs we developed in a separate filing for this Commission to consider.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-____

Direct Testimony

Of

Nathan A. Bensen

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

A. Yes. My name is Nathan A. Bensen, 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 a Senior Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co. (Great Plains), herein referred to collectively as "Company".

Q. Would you please describe your duties as a Regulatory Analyst?

A. I assist in the preparation of the annual electric rider filings in North Dakota and South Dakota, weather normalization of natural gas volumes, and other filings required by state commissions.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota with a Bachelor of Accountancy degree. I have been in my current position with Montana-Dakota for six years. Prior to starting in my current role June of 2017, I was employed by the State of North Dakota as an Auditor for sales, use and gross receipts taxes with the Office of the Tax Commissioner; and a Cost Report Auditor with the Department of Health and Human Services.

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

A. Yes. I have previously prepared testimony for this Commission and have presented testimony to the South Dakota Public Utilities Commission.

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

A. The purpose of my testimony is to present the methodology used by the Company to forecast natural gas sales data, including weather normalized volumes, projected volumes and projected customers. The totality of this process and its results are the foundational basis for the underlying projected revenues used in this rate case.

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

A. I am sponsoring the development of the projected billing units as presented on Exhibit No. ___(NAB-1) and ultimately used in the projected revenues on Statement F, Schedule F-1 pages 1 through 15. The results presented on Exhibit No. ___(NAB-1) are supported by the regression results included in Workpapers Statement F, pages 1 through 102.

Q. Would you describe the development of the normalized volumes?

A. Natural gas volumes for residential, firm general, the Minot Air Force Base, and select interruptible and transportation customers were adjusted to reflect normal weather patterns, where appropriate. Each of the aforementioned customer classes were adjusted separately. Additionally, the normalization models were separated for Montana-Dakota and Great Plains customers, which I will detail later in my testimony. Billing period sales volumes and customers, by month, were the starting point for the data utilized in the models.

First, customer classes were analyzed, with input from the Company's Gas Supply Department, to determine whether natural gas usage was associated with heating purposes and therefore correlated with weather. The general idea of heat-sensitivity is that some customers will increase the amount of natural gas that they consume as the outside temperature drops. Typically, this increase in consumption is cyclical with the calendar – as fall and winter set in, natural gas volumes sold to customers tend to increase. However, there are certain customers and instances in which colder weather is not correlated with the amount of natural gas consumed – these customers are considered non-heat-sensitive.

All firm service customer classes were determined to be heat-sensitive. Interruptible and transportation customers were analyzed on an individual basis and grouped into heat-sensitive and non-heat-sensitive by each customer class.

Q. How were the normalized volumes calculated for heat-sensitive customers?

A. For customer classes and individual customers that were determined to be heat-sensitive, weather and billing data were incorporated into a regression model for each respective class of service. To incorporate seasonal weather patterns, billing period degree days based on a 60-degree day were included as an input in the modeled regressions. Billing data used as inputs in the model were the monthly distinct count of customers and the actual dekatherms of gas consumed. The time period for each customer class in the modeled regressions was 36 months, or 3 years.

Using the results of the regression analysis for residential and firm general service customer classes, the daily baseload use per customer was multiplied by the respective number of days in each calendar month to arrive at the monthly baseload use per customer. The use per degree day per customer was then applied to the normal billing period degree days (based on normal weather for 30 years) to determine the normalized heating use per customer. The Company has historically used 30-year normals for weather normalization purposes and believes that using 30-years of normal weather data continues to be most appropriate to capture historical weather trends. The results of each of these equations was then combined by the number of customers in each respective month to determine the normalized usage for the twelve months ended December 31, 2022.

Q. How were the volumes calculated for non-heat-sensitive customers?

A. For customers that were determined to be non-heat-sensitive, simple averages of historical consumption patterns were utilized. These averages are considered to be the appropriate volumes for the non-heat-sensitive customers. These averages were calculated at an individual customer level. For most non-heat customers, a 36 month average was calculated (January 2020 – December 2022). Exceptions to the 36 month average are discussed in more detail below.

Q. Was any consideration given to customers which changed rate classes?

A. Yes. The Company analyzed the historical data for interruptible and transportation customers that changed rate classes during the time period in the data. During the time period of 2020 through 2022, there were a number of customers that changed rates under which they took service. In its normalization models and projections, the Company ensured that customers were represented in the rate class in which they are currently billed.

The Company also discussed internally with its field operations and gas supply departments to determine if there were any foreseeable changes to the classifications of its interruptible and transportation customers. There were no known customers changing classes at the time of the preparation and finalization of the normalized and projected volumes.

Q. Were other considerations necessary for customers?

A. Yes, the removal of select customers from Rate 71 was also required. Due to the margin sharing adjustment for Montana-Dakota's grain dryers through the purchased gas adjustment, all grain drying customers and associated volumes were removed from the Company's normalized and projected volumes for Rate 71. To further ensure the integrity of the projected volumes, customers that were not active at the end of 2022 were completely removed from the entirety of the underlying data for Rate 71.

Q. How were the projected volumes calculated for heat-sensitive customers?

A. The projected volumes were based upon the calculated normalized volumes for each customer class. For the residential and firm general rate classes, the Company applied projected customer growth to the normalized volumes to obtain projected volumes. For other heat-sensitive customers and classes, the projected volumes were set equal to the normalized volumes as calculated and described previously.

Q. How were growth rates for customers for the projected years calculated?

A. A three-year average growth rate calculation was performed for the Residential, Small Firm General and Large Firm General rate classes. If the class showed a positive average growth rate, this rate was then used as representative of the growth expected for the future. Average growth rates were applied to the year-end 2022 customer counts for each rate to project 2023 customers, and then applied to the projected 2023 customers to project 2024 customers. The projected customers were then used to calculate normalized volumes as previously described.

For the residential and firm general rate classes that did not demonstrate average customer growth, as well as all other remaining classes, no growth was used so customer counts were left at their respective levels at the end of 2022.

Q. How were the projected volumes calculated for non-heat sensitive customers?

A. A majority of the projected volumes for these customers were set equal to their average volumes. Some customers in Rate 71 and 81 were observed to have varying year over year use or had a limited amount of historical use. Projected use for these customers was determined through internal conversations with the Company’s energy supply group and field operations staff. The final determination of projected volumes for these customers are outlined in the summaries and support included in Statement Workpapers, Statement F pages 1 - 102.

Q. Are there any new customers included in the projected volumes?

A. Yes. As explained in the direct testimony of Larry Oswald, the Company will provide natural gas service to the towns of Kindred and Portal starting in 2024. In addition, the projected volumes also include a large customer that will begin taking service in 2024 under Rate 74. These customers are accounted for in the projected customers and volumes outlined on Exhibit No.___ (NAB-1).

Q. You previously mentioned calculating volumes and customers independently for Montana-Dakota and Great Plains. Would you describe how this affects the normalization models and projected volumes?

A. As has been described by Ms. Kivisto, Ms. Vesey and Ms. Bosch, Montana-Dakota is proposing to incorporate Wahpeton, North Dakota, currently provided for under the Great Plains North Dakota rate book, into Montana-Dakota's North Dakota gas rate book. As this relates to the normalization models and projected volumes, it is prudent and necessary to calculate normalized and projected volumes for Wahpeton independently of those calculated for Montana-Dakota. As an example, Wahpeton residential volumes are calculated in a similar manner as those of the rest of North Dakota's residential volumes, but they are calculated independently using only residential customers, volumes and weather data for Wahpeton.

Q. How will the incorporation of Wahpeton into Montana-Dakota affect future models and volumes?

A. The models and volumes will remain separate in future rate cases until the billing phases are converged and separate rate schedules for Wahpeton are no longer necessary. At that time, it is expected that all North Dakota models and projections will be incorporated into a single model for rate case purposes.

Q. Would you describe the weather data utilized in developing weather normalized gas sales?

A. The Company purchases raw daily weather data from DTN. The data utilized in the weather normalizations is the average temperature in degrees Fahrenheit for areas that the Company provides natural gas service in North Dakota. The daily average temperature is compared to an industry standard 60 (sixty) degrees Fahrenheit and if the temperature is below 60 degrees, the difference is considered the degree day value. For example, if the average daily temperature is 55 for March 1st, then the amount of degree days is 5 (60-55=5). These temperatures are collected from seven regional weather stations in North Dakota (Bismarck, Devils Lake, Dickinson, Jamestown, Minot, Wahpeton and Williston) and the differences for each day are considered calendar degree days. These calendar degree days for each respective area are then weighted based upon the amount of historical number of bills that are sent to customers in each respective billing period cycle to calculate a billing period degree day (BPDD) for each of the three regions. These regional BPDDs are then weighted based upon the historical number of firm customer service points to calculate a system-wide North Dakota BPDD. For Great Plains, the BPDD utilizes only Wahpeton weather information.

Q. Would you describe the methodology used to calculate customer counts?

A. The Company's Customer Care and Billing System (CC&B) was the starting point for the development of the customer counts. Microsoft Excel's Distinct Count function was used to count the number of unique customers. The Count function in Excel counts the total number of values corresponding to a range of data, regardless if a specific value has multiple entries in the data set. The Distinct Count function has been utilized by Montana-Dakota and Great Plains to determine its customer counts in rate cases filed in North Dakota and other jurisdictions as it accounts for adjustments and corrections to customer bills in the CC&B data set.

Q. Does this complete your direct testimony?

A. Yes, it does.

Montana-Dakota Utilities Co./Great Plains Natural Gas Co.
Gas Utility - North Dakota
Normalization Summary
For the Twelve Months Ending December 31, 2022

	Customers				Volumes			
Sales:	Per Books	2022 Normalized	2023 Projected	2024 Projected	Per Books	2022 Normalized	2023 Projected	2024 Projected
Residential								
Rate 60 - Residential	96,879	96,879	97,489	98,205 1/	9,443,194.7	8,557,322	8,611,203	8,672,377 1/
Rate 90 - Propane	270	270	270	270	18,954.3	17,283	17,283	17,283
Rate 65 - Wahpeton	1,906	1,906	1,925	1,944	171,897.3	152,518	154,039	155,559
Total Residential:	99,055	99,055	99,684	100,419	9,634,046.3	8,727,123	8,782,525	8,845,219
Firm General								
Rate 70 - Small Firm General	11,181	11,181	11,314	11,470 1/	2,148,944.7	1,917,653	1,940,464	1,965,932 1/
Rate 70 - Large Firm General	4,885	4,885	4,928 3/	4,976 1/	6,424,219.3	5,809,095	5,882,887 3/	5,914,473 1/
Rate 70 - First Through Meter	54	54	54	54	208,887.8	208,888	208,888	208,888
Rate 92 - Small Propane	65	65	65	65	12,210.8	11,376	11,376	11,376
Rate 92 - Large Propane	8	8	9	9	17,735.1	15,349	17,268	17,268
Rate 72 - Small Optional Seasonal	3	3	3	3	1,012.1	1,439	1,012	1,012
Rate 72 - Large Optional Seasonal	12	12	12	12	12,925.6	11,940	12,926	12,926
Rate 74 - Small Contract Demand 2/	45	53	53	53	98.6	99	99	99
Rate 74 - Large Contract Demand 2/	29	35	35	36 3/	214,700.2	205,819	205,819	1,460,419 3/
Rate 65 - Wahpeton	416	416	418	420	163,630.5	143,250	143,938	144,627
Total Firm General:	16,698	16,712	16,891	17,098	9,204,364.7	8,324,908	8,424,677	9,737,020
Minot Air Force Base								
Rate 64 - Firm Service	1	1	1	1	39,895.0	37,082	37,082	37,082
Rate 64 - Interruptible - Base	1	1	1	1	516,722.4	378,032	378,032	378,032
Rate 64 - PAR Site	1	1	1	1	23,461.5	19,929	19,929	19,929
Total Minot Air Force Base:	3	3	3	3	580,078.9	435,043	435,043	435,043
Interruptible - Sales:								
Rate 71 - Small Interruptible	79	70	70	71 1/	564,778.6	500,949	508,363	518,363 1/
Rate 71 - Grain Dryer	41	0	0	0	131,744.3	0	0	0
Rate 71 - Wahpeton	16	17	17	17	863,366.3	845,488	879,788	879,788
Total Interruptible - Sales:	136	87	87	88	1,559,889.2	1,346,437	1,388,151	1,398,151
Total Sales	**115,892**	**115,857**	**116,665**	**117,608**	**20,978,379.1**	**18,833,511**	**19,030,396**	**20,415,433**
Transportation:								
Interruptible - Transportation:								
Rate 81 - Small Transportation	61	60	60	60	1,122,778.3	1,054,898	1,064,957	1,064,957
Rate 82 - Large Transportation	5	5	5	5	795,110.0	780,733	780,733	780,733
Rate 82 - Contract Cust. 81-4	1	1	1	1	430,859.3	420,999	420,999	420,999
Rate 82 - Contract Cust. 81-5	1	1	1	1	3,441,953.0	3,266,561	3,266,561	3,266,561
Rate 80 - Wahpeton - Contract	9	9	9	9	1,053,886.2	1,029,454	1,029,454	1,029,454
Total Transport	**77**	**76**	**76**	**76**	**6,844,586.8**	**6,552,645**	**6,562,704**	**6,562,704**
Total Sales and Transportation	**115,969**	**115,933**	**116,741**	**117,684**	**27,822,965.9**	**25,386,156**	**25,593,100**	**26,978,137**

1/ Projected customers and volumes will include the addition of Portal and Kindred, with service estimated to begin in the fall or 2024.

	Portal Customers	Portal Volumes	Kindred Customers	Kindred Volumes
Residential	26	3,551	75	3,300
Small Firm	7	1,030	13	1,112
Large Firm	3	2,475	3	1,823
Interruptible			1	10,000

2/ Per books, normalized and projected Dk represents actual and projected use. Rate 74 customers are also charged for daily contract demand. Contracted Demand Dk are outlined below:

Contracted Demand Dk:

	Per Books	Normalized	2023 Projected	2024 Projected
Rate 74 - Small	642.0	642	739	792
Rate 74 - Large	15,937.0	15,937	16,250	65,676 3/
	16,579.0	16,579	16,989	66,468

3/ Projected customer will take service in Rate 70 during 2023 for construction, estimated use of 23,846 Dk. In 2024, this customer will begin taking service under Rate 74 with an estimated 1,254,600 Dk use, and will have contract demand of 4,100 Dk per month.

MONTANA-DAKOTA UTILITIES CO. AND GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-___

Direct Testimony

Of

Tara R. Vesey

Q. Please state your name and business address.

A. My name is Tara R. Vesey, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I am responsible for the preparation of cost-of-service studies, fuel cost adjustments, purchased gas cost adjustments, and electric 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 Science degree in Economics. I started my career with Montana-Dakota in 2019 as a Regulatory Affairs Manager. Prior to that I was employed for 13 years by a power cooperative. During that time, I held positions of increasing responsibility, including Contract Administrator, Sales Manager, Transportation Manager, and Manager of Market Operations & Logistics.

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 Montana and Wyoming and the Public Utilities Commissions of Minnesota and South Dakota.

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 North Dakota gas operations per books cost of service for the twelve months ended December 31, 2022 and the projected cost of service for 2023 and 2024. Based on the results, I have prepared the calculation of the revenue deficiency and the calculation of the interim request.

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

A. I am sponsoring Statements A through D, Statement F, Schedule F-2, and Statements G through J, and the revenue requirement presented in Exhibit No.___(TRV-1), Interim Statements A through D, Statement F, Schedule F-2, and Statements G through J, and the interim revenue requirement presented in Exhibit No.___(TRV-2).

Q. Were these statements and exhibits prepared by you or under your direct supervision?

A. Yes, they were.

<u>Conversion of Great Plains Wahpeton to Montana-Dakota.</u>

Q. Why is this filing inclusive of both Montana-Dakota and Great Plains Natural Gas Company's (Great Plains) North Dakota Operations?

A. As stated in Ms. Kivisto's testimony, the Company and Commission Staff agreed to begin combining all gas operations within North Dakota for reporting purposes in Case Nos. PU-17-490 and PU-17-075. This was seen as a first step to having one North Dakota gas utility operation. This singular operation has thus been reflected in the 2018 through 2022 Annual Report fillings. The Company is proposing that Great Plains customers will be served under Montana-Dakota's tariffs but will continue to receive a Great Plains bill for six months following implementation of final rates in this case. At that time customers will begin receiving their natural gas bills under a Montana-Dakota invoice. There will be no change in the rates charged to customers at the time Wahpeton customers move to a Montana-Dakota invoice.

The completion of common rates between Great Plains and Montana-Dakota customers will take place in a future rate case in order to avoid significant changes in the rate structure.

Specific details related to the phases are covered in the testimony of Ms. Bosch.

Q. How has the Montana-Dakota and Great Plains information been combined in the determination of the revenue requirement?

A. The per books information in the cost-of-service study is the combination of data from Montana-Dakota and Great Plains. This information was then used to project revenue, expense and rate base information that is inclusive of both companies.

<u>Gwinner Pipeline</u>

Q. How has the Company accounted for the Gwinner pipeline?

A. The Gwinner pipeline has been excluded from the revenue as well as the Rate Base for 2023 and 2024. The revenue associated with this pipeline is collected under a separate, multiyear contract that is filed with this Commission. For this reason, the projected plant associated with the Gwinner pipeline is also excluded from the rate base.

<u>Case Description</u>

Q. What is included in this Revenue Requirement?

A. The Company is requesting $11,635,044, which represents a 7.45 percent increase, based on projected 2024.

Q. How was the $11,635,044 revenue requirement derived?

The Company has developed the projected revenue requirement based on adjustments to the sales revenue, Operations & Maintenance

(O&M) expenses, taxes and the December 31, 2023 and 2024 projected rate base.

Projected Revenue Requirement

Q. What were the results of North Dakota gas operations for 2022?

A. Statement A, pages 2 and 3 show the per books income statement and rate base for the North Dakota gas operations for 2022. As shown on page 2, North Dakota gas operations produced a return on rate base of 5.482 percent for the twelve months ended December 31, 2022. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the referenced Statements.

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

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 those that 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 test period are you using to determine the revenue requirement?

A. The revenue requirement is based on a projected average 2024 test period. As stated by Ms. Kivisto, the primary reason for the increase in rates is the increased investments made since the last rate case and increased O&M expenses.

Montana-Dakota is using a future test year in accordance with North Dakota Century Code §49-05-04.1.

Q. Would you describe the development of the projected cost of service for 2023 and 2024?

A. The projected 2023 and 2024 cost of service is presented in Statement A, with schedules supporting the income statement in Statements F, G, H, I, and J. The revenues and expenses reflect the annual level that is projected for 2023 and 2024. Likewise, the rate base reflects average 2023 and 2024 plant and related balances.

<u>Income Statement</u>

Q. Would you describe the development of the projected revenues and expenses?

A. The projected revenues for 2023 and 2024 are summarized on Statement F. Mr. Bensen discusses the development of the projected volumes in his testimony, and Ms. Bosch discusses the development of the sales and transportation revenues in her testimony.

As noted earlier in my testimony, contract revenue related to the Gwinner pipeline has been excluded in the 2023 and 2024 projections as it is collected under a separate, multiyear contract that is filed with this Commission. The associated rate base has also been removed from the revenue requirement.

Other operating revenues for 2024 are projected to remain relatively flat from the 2022 level as shown on Statement F, Schedule F-2, page1. The specific details are shown on Workpaper Statement F, Schedule F-2, page 1. They are as follows:

- Reconnect Fee were adjusted to reflect a two-year average;
- NSF Check fees & MAFB Distribution System, Other Misc. Service Revenue, Meter Reading for Others, Penalty Revenue, and Miscellaneous revenue were adjusted to reflect a three-year average;
- Rent from Property was increased to reflect annualized actual activity in 2023 through the month of July;
- Heskett Pipeline Revenue was adjusted to reflect an updated revenue requirement;
- Sale of Sundry Junk Material and patronage Dividends were projected to remain at the 2022 value; and
- Late Payment revenues were projected for 2023 and 2024 based on the 2022 ratio of late payment revenue to billed sales and transportation revenue of 0.11 percent applied to projected 2023 and 2024 sales and transportation revenue.

Q. Would you describe the development of the operation and maintenance expenses?

A. Yes. The projected 2023 and 2024 operation and maintenance (O&M) expenses are summarized on Statement G, Schedule G-1, pages

1 through 6, with the detail provided on pages 7 through 25.

The cost of gas, shown on page 7, uses the projected sales volumes and the demand cost calculated in the June 2023 demand cost and a projected 2024 annual commodity cost of gas. The projected sales and volumes include a large customer that will begin taking service in 2024 under Rate 74 as well as the addition of the cities of Portal and Kindred, North Dakota in 2024. In addition, Montana-Dakota is proposing to integrate Wahpeton, North Dakota, currently provided for under Great Plains North Dakota gas tariff, into Montana-Dakota's North Dakota gas tariff as described in testimony of Mr. Bensen and Ms. Bosch.

Q. Would you describe the development of the projected other O&M expense?

A. Yes. O&M expenses were reviewed and projected by resource or cost category, some on a North Dakota only basis and some on a total Company basis. Montana-Dakota developed the O&M expenses for 2023 by reviewing current information, as well as discussions with operations personnel to determine the best information for 2023. The projections for 2024 were based on the Company's best estimate for known changes or based on an inflation factor when appropriate. To establish an inflation factor, the Company reviewed the indices published by the Congressional Budget Office, Organization for Economic Cooperation and Development, International Monetary Fund, PriceWaterhouseCoopers, and Statistica.

The rates are adjusted to reflect inflation rate of 4.10 percent for 2023 and 2.38 percent for 2024.

Q. Would you describe the development of the labor and benefits expense?

A. Yes. Labor expense is shown on Schedule G-1, page 8, with actual labor expense for the twelve months ended December 31, 2022 used as the starting point. The overall projected increase reflects the average weighted increase of 4.07% for 2023 and a projected 5.32% increase for 2024 as noted in Workpaper Statement G, Schedule G-1, pages 9 through 11. Incentive compensation has been adjusted to reflect 12.21% of straight time and vacation.

Benefits are shown on Schedule G-1, page 9. Benefits expense consists of medical/dental insurance, pension, post-retirement, 401K, and workers compensation. Each of these items was adjusted individually. Medical/dental expense reflects an increase of 13.0 percent for 2023 and 2024 based on effective 2023 premiums and 13.0 percent as shown on Workpaper Statement G, Schedule G-1, page 12. Pension and post-retirement expense for 2023 and 2024 is based on the 2023 Actuarial Estimate. Please see Workpaper Statement G, Schedule G-1, pages 13 through 19. Projected 401K, workers compensation, and other benefits expense reflected the straight time labor increase of 4.07 percent for 2023 and 5.32 percent for 2024 as shown on Workpaper Statement G, Schedule G-1, page 9.

Q. Would you describe the other projected O&M expense items

A. Yes. The projected subcontract labor expense (Statement G, Schedule G-1, page 10) for 2023 increased to reflect additional subcontractor costs for line locating and leak surveying. Subcontract labor expense for 2024 was adjusted to reflect inflation at 2.38 percent based on an average of the five indices described above. Distribution and Customer Accounts for 2024 decreased slightly due to the reduction in subcontractor use for leak detection (due to the purchase of the Picarro leak survey system supported in the testimony of Mr. Micheal Schoepp), the decreased need of line locating, and the sale of the Customer Care Facility. A&G reflects an increase due to support for new software and technology.

Materials expense (Statement G, Schedule G-1, page 11) for 2023 is expected to increase reflecting a 9.4 percent increase in gas distribution and transmission materials as shown on Workpaper Statement G, Schedule G-1, page 21. Customer Accounts and A & G was adjusted to reflect inflation of 4.10 percent. The increase projected for 2024 is reflective of the 2.38 percent inflation rate.

Vehicles and work equipment (Statement G, Schedule G-1, page 12) reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers and excavators, including the cost of fuel, insurance, maintenance and depreciation expense. The depreciation expense on these items is charged to a clearing account (rather than to depreciation expense), where it is then recorded in O&M expense or capitalized as part of a project as the vehicle or work equipment is used. The projected expense has been updated to reflect the projected plant in service and the proposed depreciation rates as shown in Workpaper Statement G, Schedule G-1, page 23. Distribution for 2023 reflects an increase primarily due to the proposed depreciation rate change for Power Operated Equipment.

Company consumption (Statement G, Schedule G-1, page 13) is the expense for general utilities, electric and natural gas consumption in Company buildings. The electric component decreased 16.85 percent and reflects the volumes at rates reflecting the settlement in Case No. PU-22-194. Although volumes remain constant, the rates associated with 2023 decreased as they reflected the July 2023 Fuel and Purchased Power Adjustment. The 2023 rates and volumes are projected to remain at the same level for 2024. The natural gas component is also decreased 22.23 percent to reflect normalized volumes at current rates and projected cost of gas for 2023. It is projected to remain at that same level for 2024.

Uncollectible accounts expense (Statement G, Schedule G-1, page 14) is based on the ratio of the five-year average of net write-offs to sales and transportation revenue. This ratio was then applied to the projected 2023 and 2024 sales and transportation revenues, which results in a decrease in uncollectible accounts.

Projected postage expense (Statement G, Schedule G-1, page 15) for 2023 reflects a 13.18 percent increase based on the projected weighted average increase, partially offset by electronic billing savings for twelve months ending December 31, 2022. Please see Statement Workpaper G, Schedule G-1, page 35. Postage expense for 2024 is projected to increase by the 2.38 percent inflation rate.

Software maintenance (Statement G, Schedule G-1, page 16) was adjusted to reflect the estimated levels for 2023 and adjusted to reflect inflation rate of 2.38 percent and includes new 2024 software maintenance expenses. See Statement Workpaper G, Schedule G-1, page 43 through 60.

Advertising expense is shown on Statement G, Schedule G-1, page 17. Projected 2023 eliminates promotional advertising expenses and advertising expenses not applicable to North Dakota gas operations. See Statement Workpaper G, Schedule G-1, page 46. Additionally, 2024 reflects an inflation rate of 2.38 percent based on the average of the five indices.

Industry dues, (Statement G, Schedule G-1, pages 18 through 20) reflect the projected levels of industry dues. These pages also include the determined benefit to ratepayer associated with each expense.

Insurance expense reflects the current insurance level for 2023 and an increase for 2024 based on a risk management market analysis. Please see Workpaper Statement G, Schedule G-1, page 68.

Regulatory commission expense, as shown on page 22 of

Statement G, Schedule G-1, reflects the expenses to be incurred in this filing, amortized over a three-year period, and a three-year average of ongoing regulatory commission expense. In addition, it includes the expenses related to depreciation studies amortized over five years.

Rent expense, as shown on page 23 of Statement G, Schedule G-1, reflects the projected level of increase in rent. The projected 2023 reflects adjustments for increases in Distribution due to the additional building lease as well as a change to the treatment of printer rentals. Customer Accounts expense has been eliminated from the projected time periods and A&G was adjusted for 2023 due to a higher forecasted expense related to North Dakota's allocation of shared software. Projected A&G for 2024 reflects a lease extension resulting in a slightly higher rental cost.

Annual easements are shown on page 24 of Statement G, Schedule G-1 adjusted to include Radio Tower leases in support of the new 2-way radio replacement project discussed further in the testimony of Mr. Darcy J. Neigum. Projected 2024 reflects inflation rate of 2.38 percent.

The items adjusted individually above represent approximately 98.7 percent of total North Dakota gas O&M expenses, as shown on Statement G, Schedule G-1, pages 5 and 6. The remaining items, which make up approximately 1.3 percent of other O&M expense, were adjusted in 2023 by 4.10 percent and 2.38 percent for 2024 to reflect the effects of inflation.

Q. Would you describe the calculation of depreciation expense?

A. Yes. Projected depreciation expense is summarized on Statement H, page 1. The calculation of depreciation expense and associated accumulated reserve for depreciation is shown on Schedule H-2, pages 1 through 8. Concentric Advisors, ULC prepared gas and common plant depreciation studies, at the Company's request, for gas and common assets based on the plant balances on December 31, 2021. The depreciation studies are supported in the testimony of Mr. Larry E. Kennedy. The depreciation rates are shown on Statement H, Schedule H-1, Pages 1 through 3.

Q. How were taxes other than income projected?

A. Projected taxes other than income are shown in Statement I. Ad valorem taxes were calculated using the projected 2023 and 2024 average plant in service balances and applying the effective tax rate based on the ratio of 2022 ad valorem taxes to average plant balances as of December 31, 2022, by function.

Projected payroll taxes were based on the ratio of payroll taxes to labor expense for 2022 and applied to the projected 2023 and 2024 labor expense to determine the projected payroll taxes. Please see Statement I, Schedule I-1, page 2.

All other taxes other than income were projected to remain at the 2022 level.

Q. Would you describe the calculation of federal and state income taxes?

A. The projected income tax calculation for North Dakota gas operations is shown in Statement J. Interest is deductible for tax purposes and the projected interest expense, shown on Schedule J-1, page 1, is calculated on the projected rate base from Statement A, page 3, using the projected debt ratio and weighted cost of debt from Statement E, page 1.

Excess deferred income taxes are also factored into the projected income taxes for 2023 and 2024 (see Statement J, Schedule J-2, page 1). Plant related excess deferred taxes are amortized using the average rate assumption method (ARAM) and is reflected in 2023 and 2024.

North Dakota federal and state income taxes are fully normalized, so the calculation of income taxes is made on the taxable income after interest, since any tax deductions would be fully offset by deferred income taxes.

<u>Rate Base</u>

Q. Would you describe the development of the projected rate base for 2023 and 2024?

A. The rate base is summarized on Statement A, page 3 and shows the 2022 actual, adjusted and projected 2023 and 2024 rate base for

North Dakota gas operations. Statements B, C, D, and J are the supporting components of the projected rate base.

Statement B, page 1 shows the summary of projected plant in service for 2023 and 2024. The projected plant was developed by adding the capital budget items for 2023 to the 2022 plant in service balances, excluding the balance associated with the Gwinner pipeline. The projected plant is detailed in Statement B, Schedule B-1, page 1. Retirements, based on a three-year average of retirements by function, were deducted and the average 2023 balance was calculated. The process was repeated for 2024. Statement B, Schedule B-1, pages 2 through 6 detail the average Plant in Service associated with the North Dakota gas operations and the Gwinner pipeline. The revenue requirement for the Gwinner pipeline is met via a contract that is filed with this Commission and thus has been excluded from the projected rate base.

The detailed capital additions by project for 2023 and 2024 are shown on Schedule B-2, pages 1 through 9.

The projected accumulated reserve for depreciation is summarized in Statement C. The projected reserve balances were calculated using the reserve balances as of December 31, 2022 (exclusive of the Gwinner pipeline), adding the calculated depreciation expense and deducting retirements based on a three-year average of retirements, as shown on Statement H, Schedule H-2, pages 1 through 3. The average 2023 balances were then calculated, and the process was repeated for 2024 as shown on Statement H, Schedule H-2, pages 4 through 6.

Q. How were the working capital items derived?

A. The projected working capital summary is shown on Statement D, page 1. Detailed information is shown on Schedule D-1, pages 1 through 11. Materials and supplies and fuel stocks were restated to a thirteen-month average on pages 1 and 2, reflecting actual balances through June 2023 with July through December remaining at the 2022 levels.

Prepayments, which are made up of prepaid insurance, are shown on Schedule D-1 page 3. Prepayments are restated to a thirteen-month average balance, reflecting balances through June 2023. The July 2023 through December 2024 balances are based on the projected 2023 and 2024 insurance expense. Please see Statement Workpaper D, Schedule D-1, page 1.

Gas in underground storage and prepaid commodity were restated to a thirteen-month average on pages 4 and 5, reflecting actual balances through June 2023 with July through December remaining at the 2022 levels. Projected 2024 was adjusted to reflect Montana-Dakota's proposal to include Great Plains customers into the Montana-Dakota integrated system of gas costs. Thus the return on storage and return on prepaid commodity would be achieved through the Purchase Gas Adjustment process.

The unamortized loss on debt was calculated using the balances as of December 31, 2022 and adding the calculated change for 2023, which reflects a reallocation of the balance and the annual amortization, to arrive at a balance for 2023. The 2023 and 2024 balances were then averaged to reflect the 2023 average. The process was repeated to calculate the 2024 average, as shown on Schedule D-1, page 6. The associated accumulated deferred income taxes were also included.

The unamortized redemption of preferred stock cost was calculated using the balances as of December 31, 2022and adding the calculated change for 2023 to arrive at a balance for 2023. The 2023 and 2024 balances were then averaged to reflect the 2023 average. The process was repeated to calculate the 2024 average, as shown on Schedule D-1, page 7.

The loss on sale of buildings is reflected on Schedule D-1, page 8. The loss is being amortized over a 20-year period. The projected activity for 2023 is reflected and the 2022 and 2023 balances were then averaged to reflect the 2023 average balance. The process was repeated to calculate the 2024 average balance. The associated accumulated deferred income taxes are also included on page 8.

Pursuant to the approval for inclusion in Case No. PU-20-379, the provision for pensions and benefits and post-retirement are shown on Schedule D-1, pages 9 and 10. The projected activity for 2023 is reflected and the 2022 and 2023 balances were then averaged to reflect the 2023 average balance. The process was repeated to calculate the 2024 average balance.

Customer advances for construction are shown on Schedule D-1, page 11 and have been restated to a thirteen-month average balance for 2023 and 2024, with actuals through June 2023. July 2023 and the remainder of the projected period reflect the June 2023 balance, less a project that is projected to be completed. The associated accumulated deferred income taxes are also included on page 11.

Q. Would you describe how the accumulated deferred income tax balances were developed?

A. The accumulated deferred income tax balances are summarized on Statement J, Schedule J-2, page 1. The projected balances were derived by adding the changes to the deferred income taxes for 2023 and 2024 to the 2022 balances and calculating the average balance.

The changes associated with book/tax depreciation differences (liberalized depreciation and excess plant deferred income taxes) are on Schedule J-2, page 1 and display the projected changes due to the plant additions as well as existing plant. The Company is required to use the Proration Method of computing deferred taxes for all test period filings in which a forecast has been used to develop the revenue requirement to comply with IRS normalization rules. As previously mentioned, plant related excess deferred taxes are amortized using the average rate assumption method (ARAM) and is reflected in 2023 and 2024.

The accumulated deferred income taxes associated with the unamortized loss on debt, the loss the sale of buildings, the provision for pensions & benefits, the provision for post-retirement and customer advances are shown on Statement D, Schedule D-1, pages 6, 8, 9, 10 and 11, respectively. The change in accumulated deferred income taxes associated with the acquisition adjustment are the same as experienced in 2022.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Statement A, page 1, shows the calculation of the revenue deficiency of $11,635,044 based on the projected 2024 income and rate base and using the overall rate of return of 7.563 percent from Statement E, page 1 and supported by Ms. Nygard.

<u>Interim Revenue Requirement</u>

Q. Is Montana-Dakota seeking an interim increase in this case?

A. Yes, it is. As stated by Ms. Kivisto, Montana-Dakota is seeking an interim rate relief in this case pursuant to North Dakota §49-05-06.

Q. What amount of interim rate relief is the Company seeking?

A. The Company has identified an interim revenue requirement, presented in Exhibit No. ___ (TRV-2) of $10,094,838 and Statement A of the Interim Application based on the 2024 projected cost of service.

Q. Would you please describe the variances of the interim increases from the case?

A. The following items are the primary changes from the Company's general rate case filing to reflect the Commission's Order in Case No. PU-20-379:

- The Return on Equity (ROE) was modified to reflect the 9.3 percent;
- Used the currently approved deprecation rates; and
- Reduced executive incentive compensation by 50%.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
PROJECTED 2024

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$149,672,336	**$11,635,044**	$161,307,380
Transportation	6,598,674		6,598,674
Other	3,576,667		3,576,667
Total Revenues	$159,847,677	$11,635,044	$171,482,721
Operating Expenses			
Operation and Maintenance			
Cost of Gas	$106,767,865		$106,767,865
Other O&M	29,119,097		29,119,097
Total O&M	$135,886,962		$135,886,962
Depreciation	13,076,262		13,076,262
Taxes Other Than Income	3,073,189		3,073,189
Income Taxes	197,338	2,839,521 2/	3,036,859
Total Expenses	$152,233,751	$2,839,521	$155,073,272
Operating Income	$7,613,926	$8,795,523	$16,409,449
Rate Base	$216,970,104		$216,970,104
Rate of Return	**3.509%**		**7.563%**

1/ Statement A, Page 2.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS - INTERIM
PROJECTED 2024

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$149,672,336	**$10,094,838**		$159,767,174
Transportation	6,598,674			6,598,674
Other	3,576,667			3,576,667
Total Revenues	$159,847,677	$10,094,838		$169,942,515
Operating Expenses				
Operation and Maintenance				
Cost of Gas	$106,767,865			$106,767,865
Other O&M	28,342,044			28,342,044
Total O&M	$135,109,909			$135,109,909
Depreciation	14,041,548			14,041,548
Taxes Other Than Income	3,058,090			3,058,090
Income Taxes	154,126	2,463,635	2/	2,617,761
Total Expenses	$152,363,673	$2,463,635		$154,827,308
Operating Income	$7,484,004	$7,631,203		$15,115,207
Rate Base	$217,141,315			$217,141,315
Rate of Return	**3.447%**			**6.961%**

1/ Statement A, Page 2.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the North Dakota Public Service Commission

Case No. PU-23-___

Direct Testimony
of
Ronald J. Amen

November 1 , 2023

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen, and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services, including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, and affiliate transactions. We have extensive experience in rate case management, revenue requirement development, allocated embedded and marginal cost of service studies, rate design and alignment, and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America, supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission ("FERC"). The Atrium team has extensive background and experience in management positions inside electric and gas utilities and as advisors to our clients.

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 26 years of which have been in utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning and acquisition, strategic business planning, and merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies across North America. I have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in **Attachment A** to my testimony.

Q. Have you previously testified before the North Dakota Public Service Commission ("Commission")?

A. Yes. I have testified before the Commission on behalf of Montana-Dakota in Case Nos. PU-20-379 and PU-22-194.

Q. Please summarize your testimony.

A. In my testimony, I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the various rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Montana-Dakota's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate 60 Residential Bill Comparison
- Exhibit No.____(RJA-3), Wahpeton Transition Phase 1 & 2 Rate Design
- Exhibit No.____(RJA-4), Rate 70 Firm General Service Bill Comparisons, and
- Exhibit No.____(RJA-5), Wahpeton Rate 62 Residential Bill Comparison.

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Montana-Dakota 's revenue requirement among its customer classes. It is also useful for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on the book value of accounting costs (a historical period), the estimated book value of costs for a forecast test year, or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies allocate the revenue requirement between jurisdictions, classes, and customers within a class.

Q. Please discuss why cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class, use the same facilities, and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average costs as gas throughput increases, and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strictly economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs (“SAC”). The logic for this concept is that if customers’ prices exceed incremental costs, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Montana-Dakota because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system’s scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles, and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum-size distribution mains, services, meters, regulators, and customer service and accounting expenses.

Demand or capacity-related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity-related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes, such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records, as well as its system and customer load data (e.g., annual, and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment"?

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other, more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study, as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance needs to be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in Montana-Dakota's COSS?

A. Yes. Special studies were performed to determine a portion of the specific distribution plant installed to serve Montana-Dakota's Large Firm General, Small Interruptible, Large Interruptible, and Minot Air Force Base (Minot AFB) customers. The costs related to these facilities from the following plant accounts were directly assigned to the Large Firm General, Small Interruptible, Large Interruptible, and Minot AFB customer classes.

- Account 303 – General Intangible Plant. Direct assignment to Large Firm General (Rate 70), Small Interruptible Rates (71 & 81), and Large Interruptible (Rate 82).
- Account 375 – Structures and Improvements. Direct assignment to Large Firm General (Rate 70), Large Interruptible (Rate 82), and Minot AFB Delivery (Rate 64).
- Account 376 – Mains. Direct assignment to Large Firm General (Rate 70), Large Interruptible (Rate 82), and Minot AFB Distribution (Rate 65).
- Account 378 – Measuring & Regulating Equipment – General. Direct assignment to Large Firm General (Rate 70), Small Interruptible Rates (71 & 81), Large Interruptible (Rate 82), and Minot AFB Delivery (Rate 64).

- Account 379 – Measuring & Regulating Equipment - City Gate. Direct assignment to Minot AFB Delivery (Rate 64).
- Account 380 – Services, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 381 – Meters, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 383 – Service Regulators, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 385 – Industrial Measuring & Regulating Station Equipment. Direct assignment to Small Interruptible and Large Interruptible (Rates 71 and 82) and Minot AFB Delivery (Rate 64).

III. MONTANA-DAKOTA'S COST OF SERVICE STUDY

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Montana-Dakota's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include production (i.e., gas supply expenses), distribution, and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors that can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system, (2) the availability of data within the utility, and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Montana-Dakota's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of North Dakota as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the system's physical configuration is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single pressure-based operation.

Q. What are the specific physical characteristics of Montana-Dakota's system?

A. The physical configuration of Montana-Dakota's system is a dispersed / multiple city-gate, primarily distribution-only and multi pressure-based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available. Montana-Dakota maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are Montana-Dakota's classes structured for purposes of the COSS?

A. The COSS evaluated seven customer classes: Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and the Minot Air Force Base Distribution (Rate 65).

Q. Please explain the customer class labeled as Minot AFB Distribution?

A. The Minot AFB Distribution customer class represents the cost of service associated with the Minot AFB distribution system Montana-Dakota purchased in 2008. The costs associated with Montana-Dakota's ownership of this system are recovered under a contract with the Minot AFB and set forth on the Air Force

Distribution System Rate Schedule 65 authorized by the North Dakota Public Service Commission in Case No. PU-06-470. Montana-Dakota has included an updated cost of service analysis, in this case, to demonstrate that other customers are not subsidizing distribution service to Minot AFB.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations may set forth the methodological preferences or guidelines for performing cost studies or designing rates, which can influence the cost allocation method utilized by the utility.

B. Classification and Allocation of Distribution Mains

Q. How did the Company's COSS classify and allocate investment in Distribution Mains?

A. The Company classified 30% of its investment in distribution mains as customer related and 70% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Montana-Dakota's system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

Q. Please explain the basis for the Company's choice of classification and allocation methods?

A. It is widely accepted that distribution mains (FERC Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the rate classes that cause the

Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based on investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Montana-Dakota's COSS, both the zero-intercept method and the minimum system method were employed to test the reasonableness, by comparison, of the two approaches.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section that describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. With respect to Montana-Dakota's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. The zero-intercept method typically uses linear regression analysis to compare unit costs of the various sized distribution mains installed on Montana-Dakota's gas system against the size (diameter) of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. The linear regression analysis can be expressed formulaically as follows:

$$y = mx + b$$

Where: y = average cost per installed foot of Montana-Dakota's distribution mains

m = cost per installed foot, per inch of pipe diameter

x = diameter of distribution mains[1]

b = minimum cost per installed foot (the zero-intercept)

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[1] Diameter squared is used for plastic pipe mains.

This equation determines that regardless of the main's diameter, the average cost of a distribution main on Montana-Dakota's gas system will be at least equal to a minimum cost per installed foot. This per foot cost component is exclusively related to the simple fact that Montana-Dakota incurs this cost to install a main, regardless of its size. That is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of Montana-Dakota's distribution mains as distinguished from the per foot demand cost component, which is equal to a cost per foot times the diameter of the distribution main.

Q. Do the results of the zero-intercept method described above support the 30% classification of distribution mains as customer related, as used by the Company?

A. Yes. Applying the regression results for plastic and steel mains to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 32.2% of the total investment in distribution mains, on a current cost (year 2023) basis.

Q. How do the results under the zero-intercept method compare to the results under the most commonly installed, minimum-sized mains investment approach for Montana-Dakota's North Dakota service territory?

A. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch plastic pipe. 6.2 million feet out of approximately 13.6 million total feet or 46% of the distribution mains installed in Montana-Dakota's North Dakota service territory were 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic. The second most footage of installed distribution mains was 4-inch plastic pipe, approximately 1.96 million feet. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 30.7%. Compared with the zero-intercept analysis results, Atrium recommended that the Company continue to use 30% for the customer component of distribution mains.

Q. Montana-Dakota's distribution mains plant data for North Dakota indicates the installation of smaller sized pipe (1 ¼-inch or less). Why wasn't a smaller pipe size chosen for the minimum system analysis?

A. Information provided by Montana-Dakota's engineering and construction personnel indicated that using the smaller sized pipe (i.e., less than 2-inch) for distribution mains is limited to special situations, such as a street crossing from a larger size main to provide service to two or three premises. These smaller size main segments are installed when a subdivision's underground utility infrastructure – water, sewer, power – roadbeds, and curbing are installed. The smaller diameter pipes are treated for plant accounting purposes as distribution mains since no service lines will be installed until a house structure is under construction, and final grading of the property is complete.

Q. Would one expect there to be a strong correlation between the number of customers served by Montana-Dakota and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Montana-Dakota's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Montana-Dakota represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

C. Distribution and General Plant Classification and Allocation

Q. How were the remaining Distribution Plant costs treated in the COSS?

A. As discussed earlier, where possible, costs were directly assigned to the customer classes based on data in the Company's plant records. Weighting factors were developed for plant costs in FERC Account Nos. 380 (Services) and

381 (Meters) based on the size and type of the facilities and equipment. The classification and allocation of the remaining account balances of the directly assigned costs discussed earlier were based on the meters and distribution mains allocators, respectively. The costs in Accounts Nos. 374 (Land & Right of Way); 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate); and 375 (Structures & Improvements) were classified and allocated based on the distribution mains allocator. The costs in FERC Account No.387 (Other Distribution System Equipment) were classified and allocated based on the sum of the allocation of Distribution Plant Account Nos. 375 – 386.

Q. How were the General and Common Plant costs classified and allocated in the COSS?

A. With one exception, General and Common Plant costs were classified and allocated to the customer classes based on an internal allocation factor generated from the results of the classification and allocation of distribution plant costs. Common Intangible – Customer Care & Billing (CC&B) and PragmaCAD (PCAD) plant were classified as customer-related and allocated on the average number of customers.

D. Operation & Maintenance, Customer Accounts & Services, and Administrative & General Expenses

Q. How were O&M expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the Operation & Maintenance (O&M) expenses followed the treatment of the related plant accounts with the exception of Account No. 879 (Customer Installations Expense), the treatment of which followed the weighted customers allocator.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading), 903 (Customer Records & Collections) and 904 (Uncollectible Accounts). Meter reading expenses were allocated based on the total annualized number of customers weighted by meter size. A composite allocation factor was created for customer records and collections expenses based on a study of the various functions and related activities of the responsibility areas that charged to this account. Uncollectible accounts expenses were assigned to the residential and small firm general classes based on number of customers, which reflected the historical uncollectible expense experience.

Q. Please explain the treatment of Administrative and General expenses in the COSS?

A. The majority of the A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses, excluding gas supply related costs and A&G. Taxes Other than Income Taxes and their corresponding [allocation basis] include Ad Valorem taxes [Distribution plant]; Payroll, Franchise and Other taxes [O&M excluding gas costs]; and Revenue taxes [projected operating revenue].

E. Cost of Service Study Results

Q. Please explain the COSS information contained in Statement K.

A. Statement K, Schedule K-1, pages 1 – 4, provides a report entitled “Cost of Service by Component.” This report shows the total dollars and unit cost required under each rate if the projected rate of return of 7.563 percent were to be earned for the demand, energy, and customer cost components of each rate schedule along with a summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and Air Force Distribution (Rate 65).

The projected system rate of return of 3.509 percent at current rates, before allocation of the requested increase, is also shown on Statement K, Schedule K-1, page 1. The cost of service information provided on Statement K, Schedule K-1 reflects the resulting rate of return on rate base allocated to each rate class. For example, the resulting rate of return allocated to the residential rate class is 2.507 percent. A revenue increase of $8,895,183 would be required to bring the residential rate of return to the overall system average requested rate of return of 7.563 percent.

Statement K, Schedule K-2, pages 1 – 18, is a report of the projected 2024 rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in Statement K, Schedule K-3.

The COSS is based on a projected 2024 average test period for North Dakota natural gas operations sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement K, Schedule K-1, the overall rate of return for North Dakota natural gas service is 3.509%, based on the projected results of operations for the 12 months ended December 31, 2024, adjusted for known and measurable changes. The returns by customer class are shown below:

• Residential Service	2.507%
• Small Firm General Service	5.731%
• Large Firm General Service	4.959%
• Minot AFB Delivery	-24.690%
• Small Interruptible Sales & Transportation	7.067%
• Large Interruptible Sales & Transportation	4.557%
• Minot AFB Distribution	15.050%

As shown above, the Minot AFB Delivery (Rate 64) is reflecting a return of -24.690 percent for the projected twelve months ended December 31, 2024. In looking further into the contributing factor behind this negative return, the Company identified two significant projects undertaken in recent years. Both projects were undertaken due to aging infrastructure; therefore, upgrades to the town border station and line heater were necessary.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you rely upon as the basis for rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

- Efficiency;
- Cost of Service;
- Value of Service;
- Stability;
- Non-Discrimination;
- Administrative Simplicity; and

- Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Montana-Dakota.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economical equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Montana-Dakota because of the competitive supply alternatives that cap rates under its flex rates.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that “equals should be treated equally,” and vertical equity requires that “unequals should be treated unequally.” Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different. In this case, this principle is an important requirement that supports Montana-

Dakota's proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices to be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Montana-Dakota, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permits proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific, and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

- System cost characteristics such as those established in the COSS required by the Commission, or embedded customer, demand, and commodity related costs by type of service;
- Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
- Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
- Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services, and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. <u>DETERMINATION OF PROPOSED CLASS REVENUES</u>

Q. Please describe the approach generally followed in allocating Montana-Dakota's proposed revenue increase of $11,635,044 to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service, (2) class contribution to present revenue levels, and (3) customer impact considerations. These criteria were evaluated for Montana-Dakota's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 (Unity), as shown in Exhibit No.___(RJA-1), Proposed Revenue Allocation, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective. Revenue changes under this option and all remaining options for Minot AFB Distribution will not be proposed as its revenues are determined by contract with Montana-Dakota. All revenue changes shown for Minot AFB Distribution in Exhibit No.___ RJA-1 are for illustrative purposes only.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario A, Equal Percentage Increase*, in Exhibit No.___ RJA-1). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Montana-Dakota's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Montana-Dakota's class revenue proposal.

A third option was to exempt the customer classes that are above parity under current rates from receiving any revenue increase. This option would preserve the current parity ratio for the Minot AFB Distribution class (see *Scenario B*, *No Class Increase Above Parity*, in Exhibit No.___ RJA-1).

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes: Residential Service (Rate Schedules 60), Small Firm General Service (Rate Schedule 70), Large Firm General Service (Rate Schedule 70), Minot AFB Delivery Service (Rate Schedule 64), Small Interruptible Sales & Transportation Service class (Rate Schedules 71 and 81) and Large Interruptible Sales & Transportation Service (Rate Schedule 82 and 85), as shown in Exhibit No.___ RJA-1 as *Scenario C, 25% to Residential and Large Interruptible. AF Combined*.

The proposed revenue increases for two of Montana-Dakota's customer classes exceed the 23.85% system average increase. The proposed 25% revenue adjustment to the Residential Service class ensures the resulting rates will move revenues closer to the COSS for this class by improving the class's revenue to cost ratio from 0.77 to 0.96. Similarly, the proposed 25% revenue adjustment to the eligible segment of the Large Interruptible Sales & Transportation Service class (i.e., those customers not receiving Flex Rates) improves the class's revenue to cost ratio from 0.86 to 0.92.

The Small Firm General Service (0.91), Large Firm General Service (0.87), Minot AFB Delivery Service (0.25), and Small Interruptible Sales & Transportation Service (0.98), classes' revenue-to-cost (R:C) ratios were also below parity (1.00) at the Company's proposed ROR of 7.563%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes closer to or slightly above parity.

The COSS results for the remaining customer class, Minot AFB Distribution Service indicates its rate of return is above the system average rate of return at both the Company's current and proposed ROR levels. While this suggests the need for a revenue decrease in order to move this customer class closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in Exhibit No.___ RJA-1 under *Revenues at Equalized Rates of Return*, the resulting implication for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from a revenue reduction for this class, or alternatively, exempting the combined Minot Airforce Delivery and Distribution classes from revenue increases (*Scenario B*). Instead, the proposed combined revenue adjustment of a $370,233 or a 20.45% increase to the Minot Airforce Delivery and Distribution classes, will mean these classes will be slightly higher relative to unity at 1.07, the same resulting parity ratios of the Small and Large Firm General Service, and Small Interruptible Sales & Transportation Service classes. This will result in an increase in rates under Minot Air Force Delivery Rate 64 and no change in rates to Minot Air Force Distribution.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some additional level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing inter-class rate subsidies, is desirable.

Statement L, page 1, Revenues Under Current and Proposed Rates, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each customer tariff rate schedule. The proposed revenue increase by rate schedule and corresponding percentage is also shown.

The allocation of the total revenue increase of $11,635,044 to the respective rate schedules is presented in Statement L, page 3. The target revenue increase as a percentage of total class revenues, including gas costs, ranges from 9.82% to Residential (Rate 60), 6.05% to Small Firm General (Rate 70), 4.51% to Large Firm General, 20.45% to Minot AFB Delivery 4.31% to Small Interruptible, and 7.02% to Large Interruptible.

VI. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. First, the Company is proposing some structural changes to its Residential Gas Service Rate 60 (Rate 60) and Residential Propane Service Rate 90 (Rate 90) by introducing small and large Basic Service Charges, as discussed by Ms. Bosch. The rate differential between the Basic Service Charges will be based on meter capacity rated less than 425 cubic feet per hour (CFH) and meters rated at or above 425 CFH or the customer is served under elevated pressure. Montana-Dakota is also reintroducing the Distribution Delivery Charges under Rate 60 and Rate 90 that were eliminated in the Company's 2015 general rate case proceeding, as further discussed by Ms. Bosch.

Second, Montana-Dakota is proposing to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules: Residential Service (Rate Schedules 60 & 90), Small General Service (Rate Schedules 70, 72 74 & 92); Large General Service (Rate Schedule 70, 72, 74, & 92); and Large Interruptible Sales & Transportation Service (Rate Schedules 85 and 82), as shown on Statement L. The Basic Service Charges for the Small Interruptible Sales & Transportation Service (Rate Schedules 71 and 81) will remain at current the level, as described below. Following the revenue increases recovered through the Basic Service Charges, the remaining allocated revenue increases for these customer classes will be recovered in their respective volumetric Distribution Delivery Charge components.

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As presented on page 4 of Statement L the Basic Service Charge Small under Residential Rate 60 and Rate 90 is proposed at $0.921 per day, which reflects an average monthly charge of $28.01, an increase of approximately $2.93 per month from the currently effective charge. The proposed Basic Service Charge Large for Rates 60 and 90 is $1.075 per day, which reflects an average monthly charge of $32.70, which is reflective of almost 100 percent of the demand and customer classified costs for residential customers as shown in Statement L.

The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 CFH is proposed at $0.88 per day, and $2.35 per day for customers requiring the larger meters capable of measuring gas flows of 500 CFH or greater. The resulting average monthly charges will be $26.77 and $71.48 respectively, representing an increase of $3.96 per month in the Basic Service Charge applicable to customers using meters rated less than 500 CFH and an increase of $6.69 per month in the Basic Service Charge for customers requiring meters rated at 500 CFH or higher. These proposed levels of Basic

Charges for the two Firm General classes represent 100% of the customer classified costs for the Small and Large meter sizes, respectively. The rate calculations for the Firm General classes are included on pages 7 - 8 of Statement L.

The proposed Basic Service Charge applicable to Small Interruptible Sales (Rate Schedule 71) and Transportation (Rate Schedule 81) Service customers will remain at $450.00 per month. While this level of basic charge is greater than the total allocated customer related costs for the Small Interruptible Service class, it improves the level of fixed costs attributable to the class recovered through a fixed monthly charge. The rate calculations for the Small Interruptible Service class are included on page 9 of Statement L.

The proposed Basic Service Charge applicable to Large Interruptible Sales (Rate Schedule 85) and Transportation (Rate Schedule 82) Service customers is $2,400.00 per month, an $800.00 increase in the level of the current charge and approximately 70% of the customer related costs this customer class, an increase from 47% at the current Basic Service Charge of $1,600.00. The rate calculations for the Large Interruptible Service class are included on pages 10 and 11 of Statement L

The proposed monthly Basic Service Charges for the two Minot Air Force Base rate schedules will increase. The proposed Basic Service Charge applicable to Air Force Firm Service – Rate 64 is $1,000, an $825.00 increase over the current charge. The corresponding proposed monthly charge for Air Force Interruptible Service – Rate 64 is $4,000.00, a $2,000.00 increase over the current charge. The rate calculations for the Minot Air Force Base Service class are included on pages 5 and 6 of Statement L As stated earlier, the proposed increases to the Basic Service Charges enumerated above will provide significant improvement in the recovery of the fixed costs via fixed charges.

Q. Do increases in Basic Service Charges, such as those proposed by Montana-Dakota, discourage conservation of the natural gas commodity?

A. No. For example, under the Company's proposed increase to its Residential Basic Service Charge, customers will continue to have a financial incentive to pursue energy efficiency measures. The portion of the customer's gas bill represented by the Company's Small Basic Service Charge is less than half of the combined total bill, including the gas commodity charge incurred by the customer. As depicted in the accompanying Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison, the portion of the typical residential customer's annual bill represented by the average monthly Basic Service Charge increase of $2.93 per month is approximately 4.2% of the total increase in a small residential customer’s bill. The effect of raising the proposed Basic Service Charge by $0.0966 per day, the equivalent of $2.99 per month in January, the month in which the most gas is typically consumed by residential heating customers, is only 2.6% of the total January bill. This is a relatively small amount. The commodity cost of gas[2] is 69% of the customer's bill in January, which continues to provide a strong economic price signal that may influence the customer's ongoing gas consumption decisions. In my opinion, the relatively small amount of fixed costs added to the Basic Service Charge that would otherwise be recovered in the volumetric Distribution Delivery Charge will not materially affect a customer's decision to use more or less gas.

[2] Montana-Dakota’s proforma cost of gas in the COSS is $5.229 per Dk.

By recovering its fixed distribution costs in the Residential Basic Service Charge, utilities can continue to promote energy efficiency and conservation for its customers while moderately reducing the real threat of margin losses due to declining gas sales per customer.

Q. Does a volumetrically weighted rate design provide the most appropriate prices signals to customers related to gas consumption?

A. No. A volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the gas utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the gas utility's system; and (4) needlessly inflate bills in the winter months, when customers face the greatest pressure on their household budgets from utility bills. Montana-Dakota's rate design proposal to increase the level of its Basic Service Charges moves in the right direction to minimize these undesirable effects and best aligns the price signals to customers with the underlying costs of providing gas delivery service.

A Basic Service Charge that better reflects the level of customer related costs will result in a customer's annual bill more accurately reflecting the non-gas revenue amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity in their monthly bills.

In summary, a Basic Service Charge provides increased bill stability for customers and increased revenue stability for the Company.

Q. The Company is proposing to re-introduce a volumetric charge to its residential rate schedules. Do you agree with the Company's proposal considering the previous line of questions?

A, As discussed by Ms. Bosch, and reflecting on my earlier testimony regarding rate design principles and objectives, it's certainly appropriate for other non-cost causation considerations that factor into a utility's decision making when proposing changes to its rate structures. The re-introduction of a volumetric charge to the Company's residential rates is one such example of a decision based on other factors a utility considers when choosing how to structure its proposed rates. Nevertheless, I consider the collection of fixed distribution costs through fixed charges, whether customer related or demand related, provides a utility with economically efficient cost recovery, while not adversely affecting the promotion of energy efficiency and conservation.

Q. In view of the Residential Basic Service Charge proposed by the Company, can you offer any further analysis that would evaluate the magnitude of increases to which <u>individual</u> customers will be exposed?

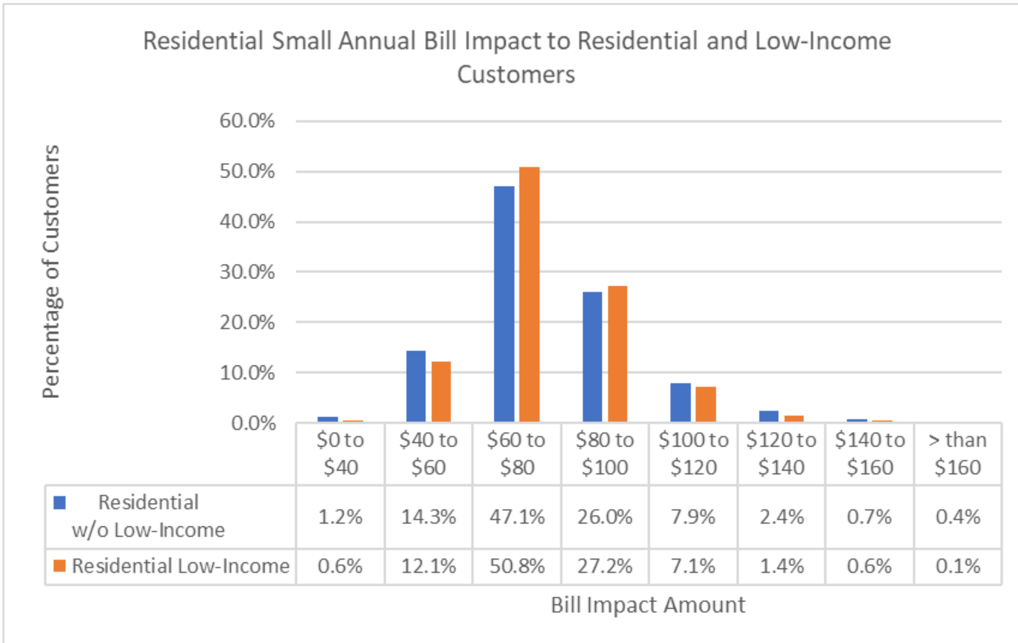
A. Yes. This can generally be assessed by analyzing how a change in rates impacts a customer's total bill, rather than the individual rate components, and is best analyzed by looking at the sum total of the customer's bills over a twelve-month period. The analysis should look at the amount of change in dollars paid instead of merely focusing on percentage increases. This is because the percentage increase in a smaller bill appears relatively high.

Q. Have you performed the analysis you recommend for the Company's Residential Basic Service Charge – Small proposal?

A. Yes. Following as *Figure 1*, is a chart showing the impact that an increase from the current Residential Basic Service Charge to the Company's proposed $0.921 per day Basic Service Charge – Small would have on bills paid by the qualifying Residential customers and Residential low-income customers over a twelve-month period. This chart shows that 98% or Residential and Residential low-income customers would all see an annual increase of $60.00 to $80.00, an average monthly increase between $5.00 and $6.67.

Figure 1 also demonstrates the comparison of the annual bill frequencies of low-income customers with those of the general population of residential customers. Although the Company does not keep records of income characteristics of its customers, it is possible to identify customers who receive bill assistance. Low-income customers generally receive LIHEAP. The Company has provided information on the annual consumption levels of LIHEAP customers. The information presented in *Figure 1* shows that the 2,535 LIHEAP small meter customer group had annual usage profiles very similar to those of the larger Residential class. This information addresses a not uncommon perception of low-income customers, which is that they tend to be low-use customers as well.

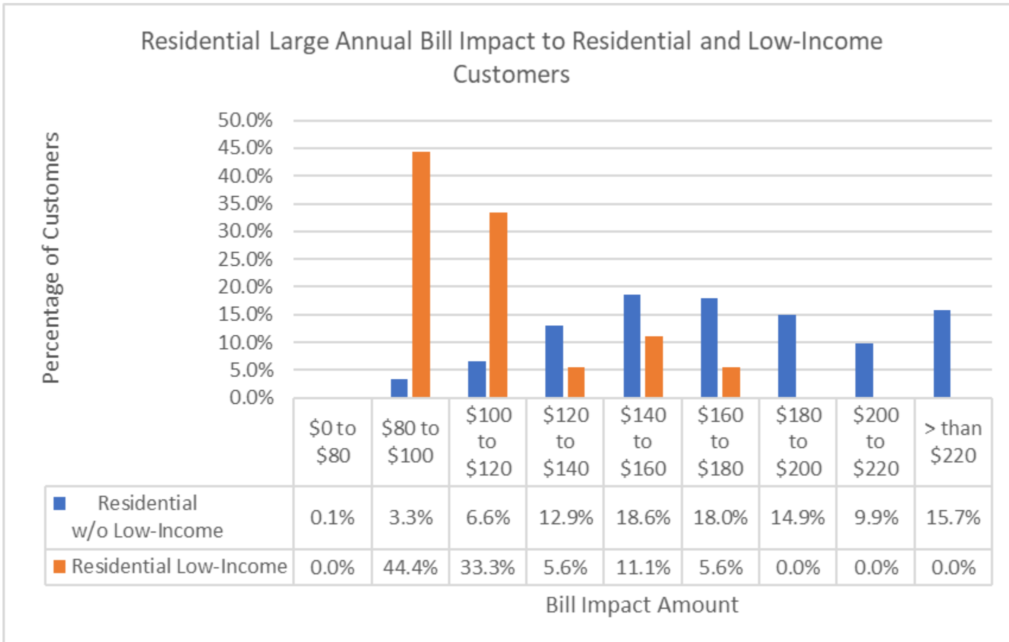
<u>Figure 1</u>



Q. Have you performed the same analysis you recommend for the Company's Residential Basic Service Charge – Large proposal?

A. Yes. *Figure 2* is a chart showing the impact that an increase from the current Residential Basic Service Charge to the Company's proposed $1.075 per day Basic Service Charge – Large would have on bills paid by the qualifying Residential customers and Residential low-income customers over a twelve-month period. This chart depicts a different relationship between the impact on Residential customers and Residential low-income customers. The chart shows that 77.7% of Residential low-income customers in the large meter customer group would all see an annual increase of $80.00 to $120.00, an average monthly increase between $6.67 and $10.00. By contrast, 90% of non-low-income Residential customers in the large meter customer group will experience annual bill increases across a wide range, from $120.00 to over $220.00. This is directly attributable to the introduction of the volumetric Distribution Delivery Charge.

<u>Figure 2</u>



Q. Are there other proposed rate design changes to Montana-Dakota's non-residential rate schedules?

A. Yes. The Firm General Service Distribution Delivery Charges will continue to exclude Firm Contract Demand Service (Rate Schedule 74) customers. However, Montana-Dakota proposes to increase the Distribution Demand Charges for both Small and Large Rate Schedule 74 customers to $8.50 per demand dk, a $0.50 increase over the current rate. The proposed rate components for all Firm General Service Rate Schedules are shown in Statement L, pages 7-8.

VII. WAHPETON RATE SCHEDULES

A. Wahpeton Firm Service Customers – Phase I

Q. Please describe the rate changes under Phase I of the two-phase integration of customers in the Wahpeton service area of Great Plains Natural Gas Co. into Montana-Dakota's North Dakota service territory.

A. As discussed by Company witness, Ms. Bosch, the integration of Wahpeton customers into Montana-Dakota's rate schedules will include changes in Rate Schedules and the rate structures within them. In Phase I of the integration, Great Plains Firm Service Rate 65 (Rate 65) customers will be moved to new Montana-Dakota Firm Service - Wahpeton Rate Schedule 62 (Rate 62). The current daily Basic Service Charge of $0.25 under Rate 65 will increase to a proposed daily Basic Service Charge of $0.50 under Rate 62, an average monthly increase of $7.61. The Distribution Delivery Charge under Rate 62 will decrease from a volumetric rate of $0.922 to a proposed rate of $0.555.

Former Wahpeton interruptible service customers who signed a Firm Service Commitment Letter for firm service at the completion of the WBI Wahpeton Expansion Project, can choose to take service under either Firm General Contracted Demand Service – Rate 74 (Rate 74), an existing Montana-Dakota rate schedule, or Wahpeton Firm Gas Service Rate 62 priced at Montana-Dakota's Firm General Service Rate 70 charges, as discussed in Ms. Bosch's testimony.

B. Wahpeton Firm Service Customers - Phase II

Q. What changes will occur to the Wahpeton Firm Service in Phase II of the rate integration?

A. As discussed in Ms. Bosch's testimony, six months following the implementation of final rates in this proceeding, new Montana Dakota accounts will be established under Residential Gas Service – Wahpeton Rate 63 (Rate 63) and Firm General Gas Service – Wahpeton 73 (Rate 73), under which all Wahpeton customers served under Rate 62 will migrate, based on their type of service. The applicable charges under Rates 63 and 73 will be the same charges as were applicable under Rate 62.

C. Wahpeton Interruptible Sales and Transportation Service Customers

Q. What changes will occur for Wahpeton Interruptible Sales Service customers under the Wahpeton transition plan?

A. Any Wahpeton remaining interruptible customers' service will transition to Montana-Dakota's existing Interruptible Sales Service – Rate 71 (Rate 71) at the conclusion of this rate case. Many of the provisions under Great Plains' Interruptible Gas Service – General Rate 71 align with Montana-Dakota's Rate 71. Upon transition, these interruptible customers will receive an increase in their current monthly Basic Service Charge from $180.00 to $450.00 and a small reduction in their existing Distribution Delivery Rate from $0.669 to $0.659 under Montana-Dakota's Rate 71.

Q. What changes will occur for Wahpeton Transportation Service customers under the Wahpeton transition plan?

A. All nine Wahpeton transportation service customers currently served under Interruptible Transportation Service – Rate 80 have executed Firm Services Commitment Letters. Therefore, Montana-Dakota is not proposing a Wahpeton-specific transportation service rate schedule in this case. Wahpeton customers that may request transportation service in the future may initiate service on Montana-Dakota's Transportation Service – Rates 81 or 82.

The proposed rate components for all Rate Schedules applicable to Wahpeton customers are located in Statement L, pages 7 to 13, and summarized in Exhibit No. ___RJA-3.

VIII. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared bill comparisons for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Small Residential customer using 81 dekatherms (Dk) per year are shown on page 1 of Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison for Residential gas service. The average monthly increase for this residential customer under the Company's proposed rate design is $5.89 or 9.76%.

Included on page 2 of Exhibit No.__(RJA-2) are the monthly and annual bill impacts for a Large Residential customer using 161 Dk per year. The average monthly increase for this residential customer under the Company's proposed rate design is $13.50 or 14.18%.

Q. What are the corresponding bill comparisons for Montana-Dakota's Small Firm General and Large Firm General customers?

A. The monthly and annual bill impacts for a typical Small Firm General customer using 172 Dk per year is shown on page 1 of Exhibit No.___(RJA-4), Rate 70 Bill Comparison for Firm General gas service. The average monthly increase for this Small Firm General customer under the Company's proposed rate design is $6.94 or 6.05%. The monthly and annual bill impacts for a typical Large Firm General customer using 1,189 Dk per year are shown on page 2 of the exhibit.

The average monthly increase for this Large Firm General customer under the Company's proposed rate design is $41.28 or 6.13%.

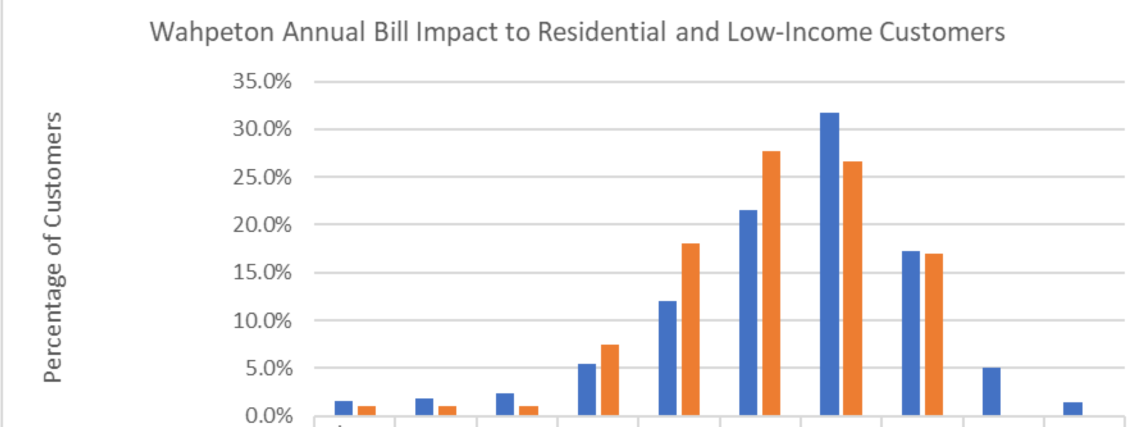
Q. Has Montana-Dakota prepared bill comparisons for its Wahpeton Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Wahpeton Residential customer using 80 dekatherms (Dk) per year are shown on Exhibit No.___(RJA-5), Wahpeton Rate 62 Residential Bill Comparisons. The average monthly increase for this residential customer under the Company's proposed Phase 1 rate design is $5.16 or 10.62%.

Q. Have you evaluated the impact on Wahpeton low-income customers' bills for the Company's proposed revenue increase allocated to Residential customers in Phase 1 of the transition to Montana-Dakota rate schedules?

A. Yes. *Figure 3* below provides a side-by-side comparison of the impact to Wahpeton Residential and low-income customers from the proposed Residential revenue increase in Phase 1 of the proposed transition of Wahpeton customers into the Montana-Dakota rate structure. The chart shows the dispersion of the annual bill increases under the proposed daily Basic Service Charge increase and the corresponding decrease to the Distribution Delivery Service Charge. Over half of both Wahpeton Residential (53.2%) and low-income Residential (54.3%) customers will experience an annual bill increase between $50.00 and $70.00 in Phase 1 of the transition. Another 23.1% of Wahpeton Residential customers and 28.8% of Wahpeton low-income Residential customers will see an annual increase under $50.00.

Figure 3



	less than $0	$0 to $20	$20 to $30	$30 to $40	$40 to $50	$50 to $60	$60 to $70	$70 to $80	$80 to $90	> $90
Residential w/o Low-Income	1.5%	1.8%	2.3%	5.5%	12.0%	21.5%	31.7%	17.3%	5.1%	1.4%
Residential Low-Income	1.1%	1.1%	1.1%	7.4%	18.1%	27.7%	26.6%	17.0%	0.0%	0.0%

Bill Impact Amount

Q. Does this conclude your direct testimony?

A. Yes.

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska, Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

44

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018, 2021)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight on the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)
Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)
Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)
Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)
Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)
Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Philadelphia Gas Works PGW (2023)

Mr. Amen led an Atrium team engaged by PGW to review the mechanics, input data, billing controls, and weather trends surrounding PGW's Weather Normalization Adjustment ("WNA") formula to understand the factors that contributed to the abnormally high WNA charges in June 2022. Atrium's review identified structural factors inherent in PGW's WNA mechanism that may have contributed to the anomalous WNA amounts billed to customers in June 2022. Mr. Amen filed testimony with Atrium's findings and recommendation in the pending general rate case before the Pennsylvania Public Utility Commission.

Potomac Electric Power Company (PEPCO) (2022-2023)

Mr. Amen led an Atrium team engaged by PEPCO on behalf of services requested by the Public Service Commission of the District of Columbia ("DC Commission"), for comprehensive evaluation of the processes, procedures, mechanics, and internal controls surrounding PEPCO's Bill Stabilization Adjustment ("BSA"). Atrium provided independent audit services sought by the DC Commission, including a) independently evaluate the timing, impact and magnitude of the billing determinant error that was identified during Formal Case No. 1156; b) independently confirm that current BSA processes and procedures are properly and timely executed as designed; c) independently confirm that current Pepco BSA internal controls are properly and timely executed; d) independently identify any recommended process and procedural improvements, as well as any recommended changes in existing internal controls or new internal controls; and e) independently conduct a comprehensive review of Pepco's BSA deferral balances by customer class, with an overall determination of the breakdown of BSA deferral balances by key drivers for each customer class. Our audit report and recommendations were filed with the DC Commission in July 2023.

Summit Natural Gas of Maine, Inc. (2022 - 2023)

Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness testimony support for the utility's gas general rate case and multi-year rate plan before the Maine Public Utilities Commission. Responsibilities included determination of an optimal normal weather period for purposes of normalizing test year billing determinants, followed by the weather normalization process of determining a representative level of gas throughput for the Company's test year. The case resulted in an all-party settlement before the Maine PUC.

Black Hills Energy Arkansas (2021-2022)
Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for the utility's gas general rate case before the Arkansas Public Service Commission. The case resulted in a settlement before the Arkansas PSC.

Until Electric System and Northern Utilities, Inc. (2021 - 2022)
Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)
Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022 - 2023)
Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission (MPSC) and North Dakota Public Service Commission (NDPSC). Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. The cases resulted in settlements approved by the respective Commissions.

Mr. Amen also represented the client's interests (as well as those of neighboring utility clients NW Natural and Puget Sound Energy) in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Mr. Amen supported electric general rate case filings in Montana and North Dakota, including a marginal cost study in Montana, and allocated cost studies, revenue apportionment and rate design in both jurisdictions.

Mr. Amen and Ms. Lieberman recently supported a gas general rate case filing in MDU's Idaho affiliate, Intermountain Gas. Support included a class level, design day load study across the utility's seven temperature zones, using a combination of AMI (60% penetration) and monthly billing data, class allocated cost of service study, class revenue apportionment, and rate design.

Mr. Amen is currently supporting gas and electric general rate case filings in MDU's South Dakota service territory, including gas and electric allocated cost studies, revenue apportionment and rate design (filed August 2023).

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives, and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018, 2022)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Future project work involves innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities.
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions.
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:

    - Application Fees
    - Non-Compliance Fees

- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model, and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)
Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)
For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)
Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007,

2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)
Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)
Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)
Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)
Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending

mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)
Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)
Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)
In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond

Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- South Dakota Public Utilities Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA

Proposed Revenue Allocation

	Total North Dakota	Total Residential	Total Small Firm General	Total Large Firm General	Total Air Force Delivery	Total Small Interruptible	Total Large Interruptible	Total MAFB Distribution
Revenue to Cost Ratio Under Current Rates	0.81	0.77	0.91	0.87	0.25	0.98	0.86	1.41
Revenues at Equalized Rates of Return								
Revenue Increase	11,635,044	8,895,183	551,410	1,679,656	440,378	39,406	162,322	(133,311)
Total revenue at equalized rates of return	61,594,189	38,847,717	6,110,933	12,875,890	586,708	1,686,556	1,163,696	322,689
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Secnario A: Equal Percentage Increase								
Revenue Increase	11,635,044	6,975,681	1,294,764	2,607,504	34,079	383,607	233,211	106,198
Total revenue at equalized rates of return	61,594,189	36,928,215	6,854,287	13,803,738	180,409	2,030,757	1,234,585	562,198
Percent Increase	23.29%	23.29%	23.29%	23.29%	23.29%	23.29%	23.29%	23.29%
Parity Ratio	1.00	0.95	1.12	1.07	0.31	1.20	1.06	1.74
Secnario B: No Class Increase Above Parity								
Revenue Increase	11,635,044	8,963,600	551,410	1679656	440378	0	0	0
Total revenue with no increase to classes above Parity	61,594,189	38,916,134	6,110,933	12,875,890	586,708	1,647,150	1,001,374	456,000
Percent Increase	23.29%	29.93%	9.92%	15.00%	300.95%	0.00%	0.00%	0.00%
Parity Ratio	1.00	1.00	1.00	1.00	1.00	0.98	0.86	1.41
Secnario C: 25% to Res and Large IT. AF Combined								
25% Increase To Residential, Large IT		25.00%					25.00%	
Rate Revenue Under Current Rates for Eligible Customers	48,782,805	29,952,534	5,559,523	11,196,234	146,330	1,647,150	281,034	0
Revenue Increase - 25% to Res & Lg IT, Rest to Parity	10,135,932	7,488,134	551,410	1,679,656	440,378	39,406	70,259	(133,311)
Balance Allocated on Revenue after Brought to Parity	1,499,112		424,458	894,342	40,752	117,146		22,414
Combine AF					(110,897)			110,897
Revenue Increase	11,635,044	7,488,134	975,868	2,573,998	370,233	156,552	70,259	0
Percent Increase	23.29%	25.00%	17.55%	22.99%	253.01%	9.50%	7.02%	0.00%
Total Revenue after Increase	61,594,189	37,440,668	6,535,391	13,770,232	516,563	1,803,702	1,071,633	456,000
Parity Ratio	1.00	0.96	1.07	1.07	0.88	1.07	0.92	1.41
% increase with gas cost	7.42%	9.82%	6.05%	4.48%	20.45%	4.31%	7.02%	0.00%

1/ "eligible customers" excludes contract rate customers

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE RATE 60 BILL COMPARISON
Projected 2024
Small

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$104.00	$113.56	$9.56	9.19%
February	13	91.06	99.46	8.40	9.22%
March	13	93.54	102.22	8.68	9.28%
April	7	61.33	67.30	5.97	9.73%
May	5	51.71	56.89	5.18	10.02%
June	2	35.19	38.97	3.78	10.74%
July	1	30.79	34.22	3.43	11.14%
August	1	30.79	34.22	3.43	11.14%
September	1	29.96	33.30	3.34	11.15%
October	4	46.48	51.22	4.74	10.20%
November	7	61.33	67.30	5.97	9.73%
December	12	88.31	96.56	8.25	9.34%
Total	81	$724.49	$795.22	$70.73	9.76%

Average Increase per Month $5.89

RATE 60 - Small	Current	Proposed
Basic Service Charge	$0.8244	$0.9210
Distribution Delivery	$0.000	$0.438
Cost of Gas	$5.229	$5.229

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE RATE 60 BILL COMPARISON
Projected 2024
Large

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	29	$177.20	$197.67	$20.47	11.55%
February	26	159.03	177.44	18.41	11.58%
March	26	161.51	180.67	19.16	11.86%
April	14	97.94	111.59	13.65	13.94%
May	10	77.85	90.00	12.15	15.61%
June	4	45.65	54.92	9.27	20.31%
July	2	36.02	44.67	8.65	24.01%
August	2	36.02	44.67	8.65	24.01%
September	2	35.19	43.59	8.40	23.87%
October	8	67.39	78.66	11.27	16.72%
November	14	97.94	111.59	13.65	13.94%
December	24	151.06	169.34	18.28	12.10%
Total	161	$1,142.80	$1,304.81	$162.01	14.18%

Average Increase per Month	$13.50

RATE 60-Large	Current	Proposed
Basic Service Charge	$0.8244	$1.0750
Distribution Delivery	$0.000	$0.438
Cost of Gas	$5.229	$5.229

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Summary of Wahpeton Rate Schedule Migration

Projected 2024

Wahpeton Service	Current GPNG Rate Schedule	Proposed Phase MDU Rate Schedule	Current Rate	Proposed Rates	Equivalent Montana-Dakota Rate Schedule	Montana-Dakota Proposed Charges
Firm Service - Phase I	Firm Gas Service Rate 65	Firm Gas Service - Wahpeton Rate 62				
Basic Service Charge			$0.25	$0.50	Rates 60 and 70	
Distribution Delivery Charge			$0.922	$0.555		
Firm Service - Phase II						
Basic Service Charge		Residential Gas Service - Wahpeton Rate 63		$0.50	Rate 60 Small	$0.921
					Rate 60 Large	$1.075
Distribution Delivery Charge				$0.555		$0.438
Basic Service Charge		Firm General Gas Service - Wahpeton Rate 73		$0.50	Rate 70 Small	$0.88
Distribution Delivery Charge				$0.555		$1.382
Basic Service Charge					Rate 70 Large	$2.35
Distribution Delivery Charge						$1.266
Interruptible Sales Service	Interruptible Gas Service Rate 71	Small Interruptible Sales Service Rate 71				
			$180.00	$450.00		
			$0.6690	$0.6590		

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
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	34	$240.95	$252.05	$11.10	4.61%
February	29	206.69	216.36	9.67	4.68%
March	29	208.94	219.00	10.06	4.81%
April	17	131.35	138.79	7.44	5.66%
May	9	80.88	86.78	5.90	7.29%
June	3	41.71	46.23	4.52	10.84%
July	1	29.65	33.89	4.24	14.30%
August	1	29.65	33.89	4.24	14.30%
September	2	35.31	39.62	4.31	12.21%
October	6	61.67	66.95	5.28	8.56%
November	15	118.55	125.57	7.02	5.92%
December	26	189.73	199.17	9.44	4.98%
Total	172	$1,375.08	$1,458.30	$83.22	6.05%

Average Increase per Month				$6.94	

RATE 70	Current	Proposed
Basic Service Charge	$0.75	$0.880
Distribution Delivery	$1.174	$1.382
Cost of Gas	5.229	$5.229

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
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	212	$1,368.98	$1,449.79	$80.81	5.90%
February	179	1,159.77	1,228.41	68.64	5.92%
March	183	1,190.75	1,261.44	70.69	5.94%
April	114	764.54	810.93	46.39	6.07%
May	68	483.96	514.51	30.55	6.31%
June	31	254.43	271.85	17.42	6.85%
July	25	219.68	235.23	15.55	7.08%
August	25	219.68	235.23	15.55	7.08%
September	26	223.70	239.37	15.67	7.00%
October	54	397.91	423.58	25.67	6.45%
November	105	709.23	752.48	43.25	6.10%
December	167	1,092.41	1,157.52	65.11	5.96%
Total	1,189	$8,085.04	$8,580.34	$495.30	6.13%

Average Increase per Month $41.28

RATE 70	Current	Proposed
Basic Service Charge	$2.13	$2.35
Distribution Delivery	$0.917	$1.266
Cost of Gas	5.229	$5.229

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON RATE 62 BILL COMPARISON - PHASE I
Projected 2024

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$100.02	$102.27	$2.25	2.25%
February	14	93.12	94.98	1.86	2.00%
March	13	87.72	90.70	2.98	3.40%
April	7	50.55	55.49	4.94	9.77%
May	4	32.36	38.64	6.28	19.41%
June	1	13.65	20.79	7.14	52.31%
July	1	13.90	21.29	7.39	53.17%
August	1	13.90	21.29	7.39	53.17%
September	1	13.65	20.79	7.14	52.31%
October	3	26.21	32.86	6.65	25.37%
November	8	56.71	61.27	4.56	8.04%
December	12	81.56	84.91	3.35	4.11%
Total	80	$583.35	$645.28	$61.93	10.62%

Average Increase per Month $5.16

RATE 62	Current	Proposed
Basic Service Charge	$0.25	$0.50
Distribution Delivery	$0.922	$0.555
Cost of Gas	$5.229	$5.229

MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.

Before the Public Service Commission of North Dakota

Case No. PU-23-____

Direct Testimony
of
Stephanie Bosch

Q. Please state your name and business address.

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

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

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the application of tariffs, and the preparation of miscellaneous rate filings.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and

Financial Economics. I joined Montana-Dakota in June 1997 as a Rate Clerk in the Regulatory Affairs Department and realized positions of increasing responsibility within the Regulatory Affairs Department until 2011 when I left the Company. In 2013 I returned to the Company as a Regulatory Analyst before attaining my current position in August of 2015.

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

A. The purpose of my testimony is to present the gas revenues at current rates, as included in Statement F, Schedule F-1 of this Application, and the proposed rate schedules provided in Appendix B to the Application, as well as the proposed changes in the Company's tariff, including the Company's plan for transitioning Wahpeton customers under the Company's North Dakota gas tariff.

Finally, I will present the apportionment of the interim increase to the various rate classes and the proposed interim rate schedules provided in Appendix A to this Application for Interim Increase in Natural Gas Rates.

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

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming and the Public Utilities Commissions of Minnesota and South Dakota.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement F, Schedule F-1 and the proposed rate schedules provided in Appendix B to the Application.

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

<u>Gas Revenues at Current Rates</u>

Q. Would you please explain the gas revenues included in Statement F, Schedule F-1?

A. Yes, as shown in Statement F, Schedule F-1, Montana-Dakota applied the Basic Service Charges and Distribution Charges applicable under each rate schedule, and as authorized in the Company's last general gas rate case, Case No. PU-20-379, to the projected number of customers and gas usage, identified by Mr. Nathan Bensen, to derive the gas revenues. Interruptible sales and transportation customers were priced at the applicable rate schedule's maximum rate per Dk unless service is being provided for under a contract rate. The Cost of Gas rates and Cost of Propane rate are reflective of the commodity gas rates and demand costs as described in the direct testimony of Ms. Tara Vesey.

<u>Wahpeton Integration</u>

Q. Montana-Dakota is again proposing the integration of the Great Plains' Wahpeton service area under Montana-Dakota's North Dakota gas tariff. Before you provide the specifics of the Company's integration plan, could you please provide a brief background of the Company's previous attempts here?

A. Yes, I can. On February 3, 2017, in compliance with Case No. PU-16-604 which required Great Plains to file updated tariff and rate schedules for all class of customers, Great Plains filed an application to revise its tariff in Case No. PU-17-075 in which the Company proposed a number of changes to its tariff that would align the Great Plains' tariff and rate schedules and structures with Montana-Dakota's gas tariff and rate schedules and structures.

As part of the settlement agreement approved in that case and Case No. PU-17-490 (Tax Reform case), Great Plains agreed to withdraw its request to modify the rate structures proposed and roll Great Plains' rate structures into Montana-Dakota's rate structures upon filing the next Montana-Dakota rate case.

The next Montana-Dakota rate case was Case No. PU-20-379, the Company's last general rate case. In that case, Montana-Dakota proposed a two-phase rate integration plan to bring the Great Plains' Wahpeton customers under Montana-Dakota's gas tariff. Ultimately, the settlement agreement that was approved delayed the integration of rates for Great Plains' customers, or Phase II of the proposed integration plan, until Montana-Dakota's next filed rate case.

Q. What were some of the concerns expressed regarding the Company's proposed Wahpeton integration plan in Case No. PU-20-379?

A. The two concerns expressed were customer confusion regarding the bill change and customer bill impacts.

Q. What is the Company proposing with this Wahpeton integration plan that will address the concerns expressed regarding customer confusion and customer bill impacts?

A. First, to address customer confusion, Mr. Larry Oswald, as explained more fully in his direct testimony, developed a more robust communication plan this time that will, not only inform customers of the integration that will occur, but also provide an opportunity for one-on-one discussions with Company personnel on what this means for the customer.

Then, to address the customer bill impact concerns, the Company opted to limit the actual change in rates to Phase I only in this case and have Phase II include only the movement of Wahpeton customers to a Montana-Dakota account with no corresponding change in rates. The 2020 rate case included rate changes in both phases of the integration plan.

The Company's proposed integration plan also acknowledges that the bill impacts to Wahpeton firm customers would be too great, at this time, to move these services under Montana-Dakota's Residential Gas Service Rate 60 or Firm General Gas Service Rate 70 at the time final rates are implemented and therefore, the Company is proposing to introduce new Wahpeton-specific firm rate schedules under the Montana-Dakota gas tariff.

Q. Please expand on the Company's integration plan.

A. The Company is proposing the integration of Wahpeton customers to Montana-Dakota customers effective upon Commission approval of the Company's request at which time the Great Plains North Dakota gas tariff will be eliminated and all Wahpeton customers moved under Montana-Dakota's North Dakota gas tariff and rate schedules. However, the actual implementation will need to be accomplished across two phases.

Q. Why will the actual implementation of this integration require two phases?

A. Today, customers in Wahpeton receive natural gas service under the rates and general provisions authorized by this Commission under the Great Plains North Dakota gas rate book. As such, Wahpeton customers are billed independent of Montana-Dakota customers in the Company's billing system where customers have a Great Plains account and receive a Great Plains bill. A phased approach is necessary to step through the process of stopping gas service as a Great Plains customer and starting service as a Montana-Dakota customer when coupled with rate changes.

A factor also influencing the Company's decision to propose a phased integration is the Company's proposed interim request. Upon Commission approval of the Company's request to implement interim rates, Wahpeton customers will begin being billed the authorized interim rate, under the Great Plains North Dakota gas tariff and reflect on the customer's Great Plains bill, which will continue through the implementation of final rates in this case. If the final revenue requirement is ultimately less than the interim request implemented, an interim refund is necessary. As the interim rate will have been billed under a Great Plains' rate schedule and on a Great Plains' account and bill, it is necessary, that in the event of a refund, the refund also be accomplished on a Great Plains' bill. This provides consistency and transparency from the initial billing of the interim through any refund that may be necessary.

Q. Please describe the Company's phased in approach.

A. The Company is proposing a two-phased approach for incorporating Wahpeton into Montana-Dakota's North Dakota gas rate book. Phase I will commence with the implementation of final rates in this case. Separate rate schedules will be established under Montana-Dakota's North Dakota gas rate book for the Wahpeton firm service rates, while Wahpeton interruptible and transportation customers will have their service moved to service under an existing Montana-Dakota rate schedule.

<u>Firm Service Customers</u>

Today, Wahpeton firm customers take service under Great Plains' Firm Gas Service Rate 65 class, which includes both residential and general service customers. In Phase I, Great Plains' Rate 65 customers would have their service moved under new Montana-Dakota rate, Firm Gas Service – Wahpeton Rate 62 (Rate 62), however customers would continue to have a Great Plains account and receive a Great Plains bill. Then six months following the implementation of final rates in this case, Phase II will commence. Customers' Great Plains accounts will stop and new Montana-Dakota accounts established under either Residential Gas Service – Wahpeton Rate 63 or Firm General Gas Service – Wahpeton Rate 73, dependent on the customer's service. The charges applicable under Rates 63 and 73 will be the same charges as those under Rate 62, however, the establishment of service under Rates 63 and 73 accomplishes two significant milestones in the process of integrating Wahpeton customers into Montana-Dakota as Wahpeton customers will now be Montana-Dakota customers and the Wahpeton firm service class will be separated into residential and firm general customers. This separation is an important step as it further aligns Wahpeton firm service customers with Montana-Dakota's firm service rates where there are separate rate schedules for residential and firm general service.

A customer's service will be initiated under either Rate 63 or Rate 73 in accordance with the definition of service included in Montana-Dakota's General Provisions Rate 100's Rules for Application of Gas Service (Section V.3.):

- Residential Gas Service Rate 63 would be available to customers using firm natural gas for domestic purposes.

- Firm General Gas Service Rate 73 would be available to all non-residential firm gas service customers.

Interruptible Sales Service Customers Moving to Firm Service

As discussed by Mr. Larry Oswald, Montana-Dakota obtained Firm Service Commitment Letters from all but three Wahpeton interruptible service customers, where the customers committed to taking firm service from Montana-Dakota for a period of ten years from the in-service date of the WBI Wahpeton Line. Under the commitment letters, customers further agreed to take service under either Montana-Dakota's Firm General Service Rate 70 (Rate 70) or Firm General Contracted Demand Service Rate 74 (Rate 74).

As Rate 74 will be a new rate schedule available to Wahpeton customers at the conclusion of this rate case, Montana-Dakota opted to have customers, who signed a Firm Service Commitment Letter and who choose Rate 74, initiate service under Montana-Dakota's Rate 74 in lieu of establishing a separate Wahpeton-specific rate schedule reflecting Rate 74's charges.

Customers who signed a Firm Service Commitment Letter and who choose Rate 70 will have service initiated under Firm Gas Service – Wahpeton Rates 62 (and eventually Rate 73), where the proposed rates for customers who signed a Firm Service Commitment Letter reflect the same proposed charges as Rate 70. This honors the commitments made in these signed letters but also recognizes there is transition period until such time as separate firm service rate schedules are no longer needed for Wahpeton customers. This transition period ceases when Wahpeton firm rates are the same as Montana-Dakota's firm rates.

Consistent with Phase I for Rate 62 customers, these customers will continue to have a Great Plains account and receive a Great Plains bill for six months following the implementation of final rates. At the end of the six months, these customers' Great Plains service will cease and new Montana-Dakota accounts initiated with customers receiving a Montana-Dakota bill.

<u>Interruptible Sales Service Customers</u>

For those Wahpeton customers remaining an interruptible service customer, the customer's service will commence under Montana-Dakota's existing Small Interruptible Sales Service Rate 71 (Rate 71) at the conclusion of this case. As many of the provisions under Great Plains' Interruptible Gas Service – General Rate 71 already align with Montana-Dakota's Rate 71 schedule, Montana-Dakota opted to not propose a Wahpeton-specific interruptible service tariff, and instead move Wahpeton interruptible customers under Montana-Dakota interruptible sales rate schedules in Phase I.

Consistent with all other Wahpeton customers, these interruptible customers will continue to have a Great Plains account and receive a Great Plains bill for six months following the implementation of final rates. At the end of the six months, customers' Great Plains service will cease and new Montana-Dakota accounts initiated with customers receiving a Montana-Dakota bill.

Transportation Service

Currently Great Plains has nine transportation customers. All nine customers opted to sign a Firm Service Commitment Letter and therefore, at the conclusion of this case, there will be no remaining transportation customers. Therefore, Montana-Dakota chose to not propose a Wahpeton-specific transportation service rate schedule. Wahpeton customers wanting transportation service will commence service under Montana-Dakota's Transportation Service Rates 81 or 82.

A summary of the Company's integration plan for Wahpeton is included as Exhibit No. __(SB-1) along with the number of customers affected. Also included in Exhibit No. __(SB-1) are the proposed new Wahpeton-specific rate schedules, Rates 62, 63 and 73.

Q. Please expand on Phase II or the process of moving customers from a Great Plains account to a Montana-Dakota account?

A. The Company is proposing that Phase II start six months following the implementation of final rates in this case. Phase II will involve the actual movement of Wahpeton customers to a Montana-Dakota account. The transition of Wahpeton customers will occur across a billing month. Following each bill cycle in the month of the transition, Wahpeton customers' Great Plains service will be stopped and a new Montana-Dakota account and services started under the proper rate schedule. The Company will coordinate the timing of the stop and start with a customer's actual meter read cycle in order to avoid a customer receiving two partial month bills, one from Great Plains and the other from Montana-Dakota. After the transition, the customer's next monthly bill will be a Montana-Dakota bill.

Q. What other tariff changes will Wahpeton customers see as a result of the integration?

A. In Case No. PU-17-075, the Company proposed a number of tariff changes to its North Dakota gas rate book. Many of those tariff changes aligned Great Plains' North Dakota gas rate book with Montana-Dakota's North Dakota gas rate book; however, there were some differences that remained between the two companies. With the proposed integration, the Company needs to address those remaining differences here.

In order to avoid short-term modifications that would be required of the Company's billing system in order to align and implement select provisions that will now be applicable to Wahpeton customers under the Montana-Dakota tariff as well as to simplify the communication regarding the integration, the Company is proposing some of the differences be aligned with the rate changes implemented in Phase I and one remaining difference be aligned in a future rate case when the separation of the Wahpeton firm customers into separate residential and firm general rate schedules is complete.

<u>Changes Effective in Phase I</u>

- Service extensions will now be administered under Montana-Dakota's Gas Service Extension Policy Rate 120.
- Montana-Dakota does not have minimum service connection charges as currently provided for in the Great Plains North Dakota rate book for the installation and turn on of the gas meter and regulator. These charges will stop when Phase I commences.
- Currently Wahpeton customers are assessed a late payment charge (LPC) of 1 1/3 percent per month on any amount not paid

by the due date shown on the bill. Montana-Dakota's LPC rate is one percent per month and will be the rate assessed on past due Wahpeton customer bills on and after Phase I.

<u>Change to be Included in Future Rate Case</u>

The Company is proposing the one remaining difference be aligned in a future rate case as short-term modifications would be required to bill the proposed change on a Great Plains bill. Furthermore, Montana-Dakota's seasonal reconnection provision differentiates between residential and non-residential customers today which will not occur for Wahpeton customers until Phase II of the integration plan. In order to simplify the communication with Wahpeton customers and recognizing this provision will change from Phase I to Phase II, Montana-Dakota is proposing that the seasonal reconnection fee provision applicable to Wahpeton customers today carry forward to the Montana-Dakota North Dakota gas rate book. Then in a future rate case, the Company will propose the Wahpeton specific reconnection fee provision be eliminated and the Montana-Dakota reconnection fees be applicable to Wahpeton customers.

Currently Great Plains' tariff provides for a $30.00 reconnection fee for seasonal or temporary customers for customers requesting the reconnection of service where the same customer discontinued the same service during the preceding 12-month period.

Montana-Dakota's seasonal reconnection fees are differentiated between residential and non-residential where residential customers pay the Basic Service Charge applicable during the period service was not being used and a charge of $30.00. Non-residential customers have a similar reconnection charge, but the fee applicable to seasonal businesses such as irrigation, grain dryers, or asphalt processing has the Distribution Delivery Charge revenue recognized. A $30.00 reconnection charge is also applicable.

A summary of the above tariff changes affecting Wahpeton customers is also included in Exhibit No. __(SB-1).

<u>Proposed Tariff Changes</u>

Q. The Company is also proposing some structural changes to Residential Rates 60 and 90. Can you expand on these changes and why the Company is proposing them?

A. Yes. The first change is to re-introduce a small and large Basic Service Charge applicable under Residential Gas Service Rate 60 (Rate 60) and Residential Propane Service Rate 90 (Rate 90). The rate differential will be based on meters rated under 425 cubic feet per hour and meters rated over 425 cubic feet per hour or whose service has elevated pressure.

Prior to Montana-Dakota's 2002 gas rate case, the Company had a similar rate differential in the Basic Service Charge (or Base Rate at that time). The rate differential was eliminated due to the small number of customers falling into the larger meter/rate classification. However, the Company believes it is the appropriate time to re-introduce this rate differential to recognize that these larger meters as well as those customers whose services have elevated pressure generally have higher meter costs and/or additional costs associated with them.

The second change is the re-introduction of a volumetric charge, or Distribution Delivery Charge. While the Company's preference would have been to continue with all costs being recovered through the Basic Service Charge under the Company's residential rates, Montana-Dakota acknowledges the apprehensions expressed in recent gas rates cases in North Dakota regarding the continuation of this approach. Therefore, in recognition of these apprehensions, coupled with the diversity of customers within the residential rate class and the on-going investments being made to Montana-Dakota's system, the Company is choosing to re-introduce a volumetric Distribution Delivery Charge to its residential rates at this time.

The third and final change is the re-introduction of the Distribution Delivery Stabilization Mechanism Rate 87 (Rate 87) to Rates 60 and 90. When the Company eliminated the Distribution Delivery Charges under Rates 60 and 90 in the 2015 rate case, Rate 87 was no longer warranted for residential services as all costs were collected through the rates' Basic Service Charge. With the proposed re-introduction of a volumetric charge under the residential rates, it is appropriate to also re-introduce Rate 87 to Rates 60 and 90.

Q. In addition to the new Wahpeton rate schedules mentioned earlier, the Company is also proposing Summary Billing Plan Rate 115. Please describe this new rate schedule which is provided herein as Exhibit No. ___(SB-2).

A. Summary Billing Plan Rate 115 (Rate 115) is an optional billing arrangement where qualifying customers that have multiple premises in North Dakota can choose to consolidate the billing of those premises under one account. The new rate schedule outlines the general availability of this new billing arrangement as well as the terms and conditions for enrolling in and maintaining eligibility under the plan.

The proposed rate schedule is in response to customers requesting the ability to consolidate multiple monthly Montana-Dakota bills into one account which in turn equates to one monthly bill and one payment. The Company recognizes the value of a bill consolidation program for participating customers; however, believes such an optional billing arrangement is best managed through a defined program that helps inform interested and participating customers of their responsibilities as well as the Company's parameters for continued participation in the plan.

Q. Would you briefly describe any additional changes the Company is proposing to its Montana-Dakota gas tariff?

A. The Company is proposing the following changes to its gas tariff as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- As described above, the Company is proposing to integrate the community of Wahpeton under Montana-Dakota's North Dakota gas tariff; therefore, the Company is proposing to eliminate, in it is entirety, the Great Plains' North Dakota gas tariff.
- The rates described by Mr. Amen have been incorporated into the proposed tariffs.
- The insertion of Firm General Gas Service – Wahpeton Rate 73 as Sheet No. 16 caused a corresponding shift in the sheet numbering

for Firm General Contracted Demand Service Rate 74 and Gwinner Pipeline Capacity Reservation Charge Rate 75. While proposed Rate 74 and Rate 76 reflect as if new tariff sheets due to the re-numbering of sheets, the following changes are proposed for:

- Rate 74 – updated the Availability provision to include the community of Wahpeton and to reflect that Rate 74 customers in Wahpeton will bill as a Great Plains customer until six months following implementation of rates at which time they will move to a Montana-Dakota account. The rate section of the rate schedule has also been updated to reflect the proposed rates. No other changes are proposed for Rate 74.
- Rate 75 – updated provision 3 of the rate schedule's General Terms and Conditions to reflect the Company's current extension policy rate schedule.

- Add a new General Terms and Conditions provision to the Company's residential rate schedules that allows for a residential customer's service to have elevated pressure, however, a residential customer must first consult with, and receive approval from the Company, prior to any construction of services in order to ensure the customer's request can be met.

- Update the Distribution Demand Charge under Rate 74 to reflect the distribution demand-related results of the Company's class cost of service study, shown in Statement N, Schedule N-1, as shown on Exhibit No. ___(SB-3).
- Update the base use per customer per day applicable to each rate schedule included in the Temperature Sensitive Use per Customer definition identified on the Rate 87 schedule to reflect each rate's corresponding regression analyses performed for the normalization of firm volumes in this case. In addition, and as mentioned previously, the Company is re-introducing the applicability of Rate 87 to Rates 60 and 90 and therefore those rate schedules' daily base use per customer is now included on Rate 87.
- Introduce new or update existing provisions within the Company's General Provisions Rate 100:
    - Allows the Company to turn a customer's gas meter on and, if no gas use is detected at that time, leave the gas meter on and permit the customer to relight any pilot lights on their equipment at the customer's earliest convenience. This will

eliminate the required presence of the customer at the time of a gas meter turn on, if the requesting customer consents to, and accepts responsibility for, their pilot relight(s). (Rate 100, Section IV. Liability/Customer's Equipment)

  - Updates the annual authorized usage by rate used in the determination of the Non-Residential Reconnection Fee for Seasonal or Temporary Customers, under General Provisions Rate 100, to reflect each respective rate class's average annual use from this case. (Rate 100, Section V. General Terms and Conditions/Reconnection Fee for Seasonal or Temporary Customers)

- Update Gas Meter Testing Program Rate 105 to include a reporting date of April 1 for submitting the results of the Company's annual gas meter testing, reflecting a test year of July 1 through June 30.
- There are other minor wording changes listed throughout the Company's rate book to improve the readability of the rate without modifying any conditions, update the rate and/or page references or are self-explanatory. These changes are clearly denoted on the tariff sheets in the legislative format.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue increase of $10,094,838, identified by Ms. Vesey, is proposed to be billed as a separate line item on customers' bills based on 20.856 percent of the amounts billed under the Basic Service Charge and the Distribution Delivery or Demand Charges applicable under the Company's rate schedules, excluding contract rate customers.

The calculations supporting the application of the interim increase to each rate class are provided in Statement K attached to the Application for Interim Increase in Natural Gas Rates. The proposed tariff sheets reflect the proposed interim rate of 20.856 percent applicable to the amounts billed under the Basic Service Charge and the Distribution Delivery or Demand Charges. The interim rate will not be applicable to the amount billed under the Cost of Gas or Propane. The interim increase represents an overall increase of 6.5 percent over the Company's Projected 2024 total revenues, including the cost of gas. Exhibit No. ___(SB-4) page 2 shows a typical residential bill for a Montana-Dakota customer reflecting the proposed interim increase, indicating an average monthly increase of $5.23 from current rates. Page 3 of Exhibit No. ___(SB-4) shows a typical residential bill for a Wahpeton customer reflecting the proposed interim increase, indicating an average monthly increase of $2.86 from current rates.

Q. Does this conclude your testimony?

A. Yes.

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Summary of Proposed Integration Plan for Wahpeton
Case No. PU-23-____

Change	GPNG ND Current	Proposed Phase 1 GPNG Account & Bill	Proposed Phase 2 MDU Account & Bill	# of Customers
Rate Classifications				
Firm Service	GPNG Rate 65	MDU Rate 62		
Residential			MDU Rate 63	1,944
Firm General			MDU Rate 73	422
Optional Seasonal Firm General		MDU Rate 72	MDU Rate 72	0
Firm General Contracted Demand		MDU Rare 74	MDU Rare 74	21
Interruptible Sales Service	GPNG Rate 71	MDU Rate 71	MDU Rate 71	3
Interruptible Transportation Service	GPNG Rate 80	MDU Rate 81/82	MDU Rate 81/82	0
Other Tariff Changes				
Firm Gas Extensions	GPNG Rate 105	MDU Rate 120	MDU Rate 120	
Service Line Connections				
Input loads up to 400,000 Btu/hour	$25.00			
Input loads > 400,000 Btu/hour	$50.00			
Interruptible customers	$100.00			
Late Payment Charge Rate	1.33%	1.00%	1.00%	
Seasonal Reconnections	$30.00	$30.00	$30.00	

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
Original Sheet No. 5

FIRM GAS SERVICE – WAHPETON Rate 62

Availability:

Service under this rate schedule is available to any domestic or commercial customer located in Wahpeton, North Dakota. Gas service under this rate schedule will cease six months following implementation of final rates in Case No. PU-23-___, or [date], at which time each customer's service will be re-classified as either Residential Gas Service – Wahpeton Rate 63 or Firm General Gas Service – Wahpeton Rate 73, dependent on each customer's service and as defined in Rate 100, §V.3.

Rate 62 customers will take service under a Great Plains Natural Gas Co. account and receive a Great Plains Natural Gas Co. bill until [date six months following implementation of rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk
For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

FIRM GAS SERVICE – WAHPETON Rate 62

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI Wahpeton pipeline expansion project are required to take service under the applicable rates defined herein.

2. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

3. The foregoing schedule is subject to Rates 100 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
Original Sheet No. 6

RESIDENTIAL GAS SERVICE – WAHPETON Rate 63

Availability:

For the community of Wahpeton, North Dakota for all domestic uses. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

General Terms and Conditions:

1. Residential customers must first consult with, and receive approval from, the Company prior to the construction of services if elevated pressure is desired for customer's service.

2. The foregoing schedule is subject to Rates 100 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
1st Revised Sheet No. 16
Canceling Original Sheet No. 16

FIRM GENERAL GAS SERVICE – WAHPETON Rate 73

Availability:

For the community of Wahpeton, North Dakota for all purposes, except for resale. See Rate 100, §V.3 for definition of class of service. Service under this rate schedule is available starting on or after [date six months following final rates].

Rate:

Basic Service Charge:	$0.500 per day
Distribution Delivery Charge:	$0.555 per dk
For customers who signed a Firm Service Commitment with the Company prior to November 1, 2023	
Basic Service Charge:	$2.35 per day
Distribution Delivery Charge:	$1.266 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.13, or any amendments or alterations thereto.

Cost of Gas:

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

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
1st Revised Sheet No. 16.1
Canceling Original Sheet No. 16.1

FIRM GENERAL GAS SERVICE – WAHPETON Rate 73

General Terms and Conditions:

1. Customers who signed a Firm Service Commitment with the Company prior to November 1, 2023 thereby indicating the customer's intent to take firm service at the equivalent of one of Montana-Dakota's firm general gas rates at the completion of the WBI pipeline expansion project are required to take service under the applicable rates defined herein.

2. The foregoing schedule is subject to Rates 100 through 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.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
Original Sheet No. 56

SUMMARY BILLING PLAN Rate 115

Availability:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.
   a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 8
Original Sheet No. 56.1

SUMMARY BILLING PLAN Rate 115

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
   a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Calculation of Rate 74 Distribution Demand Charge - Proposed
2023 Rate Case

Rate Classes	Net Distribution Cost of Service - Demand Component 1/	Distribution Level Peak 2/	Annual Cost	Rate 74 Demand Charge
Residential	$9,204,289	98,785		
Small Firm General	2,320,247	24,671		
Large Firm General	8,143,803	76,650		
Small Interruptible	1,227,086	10,751		
Large Interruptible	845,613	2,937		
	21,741,038	213,794	$101.69	$8.47

1/ Class Cost of Service Study, Cost by Component
2/ Class Cost of Service, Design Day Deliveries

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
Revenues Under Current and Proposed Rates - Interim

	Projected 2024			Total	Proposed	
Customer Class/Rate	Customers	Dk	Revenues	Proposed Revenue	Revenue Increase	Percent Increase
Residential - Rate 60	98,475	8,689,660	$75,121,886	$81,301,877	$6,179,991	8.2%
Firm General Service - Rate 70	16,678	9,592,393	64,191,073	67,449,828	3,258,755	5.1%
Air Force - Rate 64						
Firm	1	37,082	212,652	216,563	3,911	
Interruptible	2	397,961	1,597,987	1,624,595	26,608	
Total Air Force	3	435,043	1,810,639	1,841,158	30,519	1.7%
Small Interruptible						
Sales - Rate 71	71	518,363	2,596,388	2,736,695	140,307	5.4%
Transportation - Rate 81	60	1,064,957	926,766	1,120,052	193,286	20.9%
Total Small IT	131	1,583,320	3,523,154	3,856,747	333,593	9.5%
Large Interruptible						
Sales - Rate 85	0	0	0	0	0	
Transportation - Rate 82	7	4,468,293	1,001,374	1,059,986	58,612	5.9%
Total Large IT	7	4,468,293	1,001,374	1,059,986	58,612	5.9%
Firm Gas - GPNG Rate 65	2,364	300,186	2,062,159	2,164,872	102,713	5.0%
Interruptible - GPNG						
Sales - GPNG Rate 71	17	879,788	3,890,191	4,020,603	130,412	3.4%
Transportation - Rate 80	9	1,029,454	4,670,534	4,670,534		
Total IT	26	1,909,242	8,560,725	8,691,137	130,412	1.5%
Montana-Dakota	115,294	24,768,709	145,648,126	155,509,596	9,861,470	
GPNG - ND	2,390	2,209,428	10,622,884	10,856,009	233,125	
Total North Dakota	117,684	26,978,137	$156,271,010	$166,365,605	$10,094,595	6.5%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON - INTERIM
RESIDENTIAL GAS SERVICE

Month	Dk	Present Rate 1/	Proposed Rate	Amount of Increase	% Increase
January	17	$114.45	$119.78	$5.33	4.66%
February	14	96.29	101.10	4.81	5.00%
March	14	98.76	104.09	5.33	5.40%
April	8	66.56	71.72	5.16	7.75%
May	5	51.70	57.03	5.33	10.31%
June	2	35.19	40.35	5.16	14.66%
July	1	30.79	36.12	5.33	17.31%
August	1	30.79	36.12	5.33	17.31%
September	1	29.96	35.12	5.16	17.22%
October	4	46.47	51.80	5.33	11.47%
November	8	66.56	71.72	5.16	7.75%
December	13	93.53	98.86	5.33	5.70%
Total	88	$761.05	$823.81	$62.76	8.25%
Average Increase per Month				$5.23	

Rate 60	Current	Proposed
Basic Delivery Charge	$0.8244	$0.8244
Distribution Delivery	$0.000	$0.000
Projected Cost of Gas	$5.229	$5.229
Interim Rate		20.856%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
GPNG ND RATE 65 BILL COMPARISON - INTERIM
RESIDENTIAL GAS SERVICE

Month	Dk	Present Rate 1/	Proposed Rate	Amount of Increase	% Increase
January	15	$99.77	$104.22	$4.45	4.46%
February	14	93.12	97.27	4.15	4.46%
March	13	87.72	91.84	4.12	4.70%
April	7	50.55	53.46	2.91	5.76%
May	4	32.36	34.75	2.39	7.39%
June	1	13.65	15.41	1.76	12.89%
July	1	13.90	15.71	1.81	13.02%
August	1	13.90	15.71	1.81	13.02%
September	1	13.65	15.41	1.76	12.89%
October	3	26.21	28.40	2.19	8.36%
November	8	56.71	59.81	3.10	5.47%
December	12	81.56	85.48	3.92	4.81%
Total	80	$583.10	$617.47	$34.37	5.89%
Average Increase per Month				$2.86	

Rate 60	Current	Proposed
Basic Delivery Charge	$0.25	$0.25
Distribution Charge	$0.9220	$0.9220
Projected Cost of Gas	$5.2290	$5.2290
Interim Rate		20.856%