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

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

May 16, 2022

Executive Secretary
North Dakota Public Service Commission
600 East Boulevard Ave. Dept. 408
Bismarck, ND 58505-0480

Re: Application and Notice of Change in General Electric Rates
Case No. PU-22-___

Montana-Dakota Utilities Co. (Montana-Dakota) herewith submits its Application and Notice to increase its rates for electric service in North Dakota. Montana-Dakota submits this Letter of Transmittal and its Application and Notice with Appendices A and B, Testimony and Exhibits and Statements supporting an increase in Montana-Dakota's rates for electric service. This filing is made in accordance with Title 49 of the North Dakota Century Code and the rules and regulations promulgated by the North Dakota Public Service Commission.

The primary reason for the need for an increase in electric rates is the increased investment in production, transmission and distribution facilities and the associated depreciation, operation and maintenance expenses and taxes associated with the increased investment.

Recovery of these increased costs will provide Montana-Dakota a reasonable opportunity to earn a fair rate of return for its North Dakota electric operations.

Montana-Dakota proposes a total annual increase of $25,365,558 or 12.3 percent, based on a 2023 future test year. The increase will include changes to the

Company's base rates and the Generation Resource Recovery Rider. However, no changes to the Renewable Resource Cost Adjustment, Environment Cost Recovery Rider or Transmission Cost Adjustment riders have been included in this request. The proposed change in rates will affect customer classes as follows:

	Revenue Increase	
Customer Class	$	%
Residential Service	$14,305,328	17.3 %
Small General Service	$2,214,086	18.4 %
Large General Service	$8,262,936	7.8 %
Municipal Lighting	$84,752	7.3 %
Municipal Pumping	$480,570	13.8 %
Outdoor Lighting	$17,886	4.2 %
Total North Dakota Electric	$25,365,558	12.3 %

Please refer all inquiries regarding this filing to:

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

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

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

Mr. Paul Sanderson
Evenson Sanderson PC
103 South 3rd Street
Suite 5
Bismarck, ND 58501
psanderson@esattorneys.com

The original and nine (9) 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.

Montana-Dakota also herewith submits a check for $175,000.00 pursuant to the requirements of Section 49-05-04 of the North Dakota Century Code.

Montana-Dakota is concurrently submitting an Application and Notice for Interim Increase in Electric Rates in the annual amount of $11,422,209 to be effective 60 days from filing if the Commission suspends the rate increase sought by Montana-Dakota through its Application and Notice.

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

Attachments

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 Establish Increased Rates for Electric Service	))))	Case No. PU-22-___

* * * * * *

APPLICATION AND NOTICE

COMES NOW, Montana-Dakota Utilities Co., the Applicant in the above-entitled proceeding (hereafter "Montana-Dakota", "Applicant" or "Company") and respectfully submits the following Application and Notice, tariffs, and information in support thereof.

I.

That Montana-Dakota is a Delaware corporation duly authorized to do business in the State of North Dakota as a foreign corporation. Montana-Dakota 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.

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

NDPSC Volume No. 4	Description
5th Revised Sheet No. 1	Table of Contents
6th Revised Sheet No. 1.1	"
1st Revised Sheet No. 2	Communities Served
2nd Revised Sheet No. 2.1	"
9th Revised Sheet No. 3	Residential Electric Service Rate 10
1st Revised Sheet No. 3.1	"
3rd Revised Sheet No. 4	Optional Residential Electric Thermal Energy Storage
4th Revised Sheet No. 4.1	"
11th Revised Sheet No. 7	Optional Time-of-Day Residential Electric Service Rate 16
3rd Revised Sheet No. 7.1	"
9th Revised Sheet No. 10	Small General Electric Service Rate 20
3rd Revised Sheet No. 10.1	"
5th Revised Sheet No. 14	Irrigation Power Service Rate 25
7th Revised Sheet No. 14.1	"
11th Revised Sheet No. 15	Optional Time-of-Day Small General Electric Service
3rd Revised Sheet No. 15.1	"
5th Revised Sheet No. 18	General Electric Service Rate 30
7th Revised Sheet No. 18.1	"
1st Revised Sheet No. 18.2 (Reserved)	"
7th Revised Sheet No. 19	Optional Time-of-Day General Electric Service Rate
11th Revised Sheet No. 19.1	"
4th Revised Sheet No. 19.2	"
6th Revised Sheet No. 20	General Electric Space Heating Service Rate 32
9th Revised Sheet No. 20.1	"
2nd Revised Sheet No. 20.2	"

3rd Revised Sheet No. 22	Firm Service Economic Development Rate 34
6th Revised Sheet No. 22.1	"
2nd Revised Sheet No. 22.2	"
5th Revised Sheet No. 23	Interruptible Large Power Demand Response Rate 38
7th Revised Sheet No. 23.1	"
5th Revised Sheet No. 23.2	"
2nd Revised Sheet No. 23.3	"
3rd Revised Sheet Nos. 24, 24.1	Reserved for Future Use
2nd Revised Sheet No. 24.2	Reserved for Future Use
5th Revised Sheet No. 25	Small Municipal Electric Service Rate 40 (Closed)
8th Revised Sheet No. 25.1	"
5th Revised Sheet No. 25.2	"
8th Revised Sheet No. 26	Municipal Lighting Service Rate 41
4th Revised Sheet No. 26.1	"
5th Revised Sheet No. 32	Municipal Pumping Service Rate 48
8th Revised Sheet No. 32.1	"
2nd Revised Sheet No. 32.2 (Reserved)	"
9th Revised Sheet No. 36	Outdoor Lighting Service Rate 52
3rd Revised Sheet No. 36.1	"
1st Revised Sheet No. 36.2 (Reserved)	"
6th Revised Sheet No. 39	Renewable Resource Cost Adjustment Rate 55
1st Revised Sheet No. 39.1 (Reserved)	"
5th Revised Sheet No. 40	Generation Resource Recovery Rider Rate 56
8th Revised Sheet No. 40.1	"
5th Revised Sheet No. 41	Environmental Cost Recovery Rider Rate 57
5th Revised Sheet No. 41.1 (Reserved)	"
6th Revised Sheet No. 42	Fuel and Purchased Power Adjustment Rate 58
5th Revised Sheet No. 42.1	"
63rd Revised Sheet No. 42.2	"
13th Revised Sheet No. 42.3 (Reserved)	"
Substitute 1st Revised Sheet No.	Transmission Cost Adjustment Rate 59
10th Revised Sheet No. 43.1	"
22nd Revised Sheet No. 44	Occasional Power Purchase Rate 95 Non-Time Differentiated
18th Revised Sheet No. 44.1	"
1st Revised Sheet No. 44.2 (Reserved)	"

22nd Revised Sheet No. 45	Parallel Generation Peaking Facility Purchase Rate 96 Time Differentiated
20th Revised Sheet No. 45.1	"
10th Revised Sheet No. 45.2	"
3rd Revised Sheet No. 45.3 (Reserved)	"
2nd Revised Sheet No. 49	General Provisions Rate 100
1st Revised Sheet No. 49.1	"
Original Sheet Nos. 49.2-49.3	"
2nd Revised Sheet No. 49.4	"
1st Revised Sheet Nos. 49.5-49.7	"
2nd Revised Sheet No. 49.8	"
1st Revised Sheet No. 49.9 (Reserved)	"
1st Revised Sheet Nos. 50-51	Reserved for Future Use
1st Revised Sheet Nos. 53-56	Reserved for Future Use
2nd Revised Sheet Nos. 58-58.19	Electric Service Rules and Regulations Rate 110
3rd Revised Sheet No. 58.20	"
2nd Revised Sheet Nos. 58.21-	"
Original Sheet No. 58.31	"
Original Sheet Nos. 60-60.2	Electric Extension Policy Rate 112
1st Revised Sheet Nos. 61-62.1	Reserved for Future Use
1st Revised Sheet No. 67	Reserved for Future Use
Original Sheet Nos. 68-68.2	Selective Testing Plan For Watthour Meters Rate 131
1st Revised Sheet Nos. 70-70.1	Reserved for Future Use
Original Sheet Nos. 74-74.2	Small Qualifying Facilities (SQF) General Rules Rate 140

V.

Montana-Dakota respectfully hereby files the following described proposed rate schedules for electric 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:

NDPSC Volume No. 5	Description
Original Sheet Nos. 1 - 1.1	Table of Contents
Original Sheet Nos. 2 - 2.1	Communities Served
Original Sheet No. 3	Residential Electric Service Rate 10
Original Sheet Nos. 4 - 4.1	Optional Residential Electric Thermal Energy Storage Service Rate 13
Original Sheet Nos. 7 - 7.1	Optional Time-of-Day Residential Electric Service Rate 16
Original Sheet Nos. 10 - 10.1	Small General Electric Service Rate 20
Original Sheet Nos. 14 - 14.1	Irrigation Power Service Rate 25
Original Sheet Nos. 15 - 15.1	Optional Time-of-Day Small General Electric Service Rate 26
Original Sheet Nos. 18 - 18.1	General Electric Service Rate 30
Original Sheet Nos. 19 - 19.2	Optional Time-of-Day General Electric Service Rate 31
Original Sheet Nos. 20 - 20.2	General Electric Space Heating Service Rate 32
Original Sheet Nos. 22 - 22.2	Firm Service Economic Development Rate 34
Original Sheet Nos. 23 - 23.3	Interruptible Large Power Demand Response Rate 38
Original Sheet Nos. 25 - 25.2	Small Municipal Electric Service Rate 40 (Closed)
Original Sheet Nos. 26 - 26.1	Public Lighting Service Rate 41
Original Sheet Nos. 32 - 32.1	Municipal Pumping Service Rate 48
Original Sheet Nos. 36 - 36.1	Outdoor Lighting Service Rate 52
Original Sheet No. 39	Renewable Resource Cost Adjustment Rate 55
Original Sheet Nos. 40 - 40.1	Generation Resource Recovery Rider Rate 56
Original Sheet No. 41	Environmental Cost Recovery Rider Rate 57
Original Sheet Nos. 42 - 42.2	Fuel and Purchased Power Adjustment Rate 58
Original Sheet Nos. 43 - 43.1	Transmission Cost Adjustment Rate 59
Original Sheet Nos. 44 - 44.1	Occasional Power Purchase Rate 95 Non-Time differentiated
Original Sheet Nos. 45 - 45.2	Parallel Generation Peaking Facility Purchase Rate 96 Time Differentiated
Original Sheet Nos. 49 - 49.8	General Provisions Rate 100
Original Sheet Nos. 58 - 58.31	Electric Service Rules and Regulations Rate 110
Original Sheet Nos. 60 - 60.2	Electric Extension Policy Rate 112
Original Sheet Nos. 68 - 68.2	Selective Testing Plan for Watthour Meters Rate 131
Original Sheet Nos. 74 - 74.2	Small Qualifying Facilities (SQF) General Rules Rate 140

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 electric service and to earn a just and reasonable rate of return on its electric property devoted to providing service to its North Dakota electric customers.

VII.

The new rates contained herein will provide additional annual revenues in the annual amount of $25,365,558 based on a 2023 future test year, for electric service rendered to customers in the State of North Dakota. This request amounts to a 12.3 percent increase over current electric 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 Electric Rates in the annual amount of $11,422,209 to be effective 60 days from filing if the Commission suspends the rate increase sought by Montana-Dakota through this Application and Notice.

X.

This Application and Notice is submitted in accordance with the provisions of Section 49-05-04 of the North Dakota Century Code 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.

Respectfully submitted this 16th day of May 2022.

MONTANA-DAKOTA UTILITIES CO.,

By 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 this 16th day of May 2022.

By 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 before me this 16th day of May 2022.

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

Terese M. Birnbaum

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

OF COUNSEL:

Mr. Paul Sanderson
Evenson Sanderson PC
1100 College Drive, Suite 5
Bismarck, ND 58501
(701) 751-1243

Ms. Allison Waldon
Attorney
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

CERTIFICATE

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 certify that the 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 Establish Increased Rates for Electric 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 this 16th day of May 2022

By 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 before me this 16th day of May 2022

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

Terese M. Birnbaum

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

Appendix A

TABLE OF CONTENTS

TABLE OF CONTENTS

ELECTRIC SERVICE

Dakota Heartland Region

Almont
Apple Valley
Ashley
Beulah
Bismarck*
Braddock
Burnstad
Carson
Center
Dawson
Driscoll
Elgin
Ellendale
Forbes
Fredonia
Fullerton
Glen Ullin
Golden Valley
Hague
Hazelton
Hazen
Heil
Judson
Kintrye
Kulm
Lehr
Leith
Linton
Mandan
McKenzie
Merricourt
Monango
Napoleon
New Leipzig
New Salem
Selfridge
Steele
Sterling
Strasburg
Tappen
Venturia
Wishek
Zeeland

*Designates Region Office

ELECTRIC SERVICE

Badlands Region

Alamo
Alexander
Ambrose
Appam
Arnegard
Battleview
Beach
Belfield
Bentley
Bowbells
Bowman
Bucyrus
Burt
Carpio
Columbus
Corinth
Corteau
Coulee
Crosby
Dickinson*
Dodge
Donnybrook
Dunn Center
East Fairview
Epping
Flaxton
Gladstone
Gascoyne
Grenora
Halliday
Hamlet
Hanks
Haynes
Hebron
Hettinger
Kenmare
Killdeer
Larson
Lemmon
Lignite
Loraine
Marmarth
McGregor
Mohall
Morristown
Mott
New England
Noonan
Norma
Northgate
Portal
Powers Lake
Rawson
Ray
Reeder
Regent
Rhame
Richardton
Ross
Scranton
Sentinel Butte
Sherwood
South Heart
Springbrook
Stanley
Taylor
Tioga
Tolley
Watford City
Werner
Wheelock
Wildrose
Williston
Zahl

*Designates Region Office

RESIDENTIAL ELECTRIC SERVICE Rate 10

Availability:

In all communities served for single-phase residential electric service for domestic purposes only.

Rate:

Basic Service Charge:	$0.46 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	5.678¢ per Kwh
Over 750 Kwh per month	2.678¢ per Kwh
June – September:	5.678¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 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

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Availability:

In all communities served for single-phase residential electric for customers operating Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning purposes where electric space heating is the primary heating source. Service under this rate is not available when another energy source provided by the Company is utilized as a back-up heating source.

Rate:

Basic Service Charge: $0.75 per day

Off-Peak Energy Charge:

For all energy used during the designated hours of 10:00 p.m. to 8:00 a.m. local time.

October – May:	1.100¢ per Kwh

On-Peak Energy Charge:

For all energy not covered by the Off-Peak rating period.

October – May:	
First 750 Kwh per month	5.846¢ per Kwh
Over 750 Kwh per month	2.846¢ per Kwh
June – September:	5.846¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Thermal storage space heating facilities can include the thermal storage device(s), air-source heat pumps, and associated air handling units.

2. Unless approved by the Company the maximum thermal storage facilities that may be connected under this rate schedule is 50 Kw.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

Availability:

In all communities served for single-phase residential electric service. The customer's wiring must be so arranged that all service can be measured through one meter.

Rate:

Basic Service Charge: $0.75 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	5.718¢ per Kwh
June – September	7.218¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	2.718¢ per Kwh
June – September	4.218¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Residential Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Residential Electric Service rate or returning to the regular Residential Electric Service rate.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

SMALL GENERAL ELECTRIC SERVICE Rate 20

Availability:

In all communities served for all types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be so arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Basic Service Charge:	$0.84 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	5.997¢ per Kwh
Over 750 Kwh per month	2.997¢ per Kwh
June – September:	5.997¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Non-metered services. At the Company's discretion, the installation of a meter on a customer's service may not be warranted. In the absence of measuring a customer's use, customers will be billed a predetermined energy use amount each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment served on Company-owned poles.

4. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

IRRIGATION POWER SERVICE Rate 25

Availability:

For irrigation power service.

Rate:

Basic Service Charge:	$1.50 per day
Demand Charge:	
October – May	$1.25 per Kw
June – September	$4.25 per Kw
Energy Charge:	0.186¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

IRRIGATION POWER SERVICE Rate 25

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

Availability:

In all communities served for all types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Basic Service Charge:	$1.00 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	4.566¢ per Kwh
June – September	6.066¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	2.066¢ per Kwh
June – September	3.566¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Small General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Small General Electric Service rate or returning to the regular Small General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SERVICE Rate 30

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Primary Service:	
Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$11.00 per Kw
June – September	$14.00 per Kw
Energy Charge:	1.414¢ per Kwh
Secondary Service:	
Basic Service Charge:	$56.00 per month
Demand Charge:	
October – May	$ 9.50 per Kw
June – September	$12.50 per Kw
Energy Charge:	2.331¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 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

OPTIONAL TIME-OF-DAY GENERAL ELECTRIC SERVICE Rate 31

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Primary Service:	
Basic Service Charge:	$97.00 per month
On-Peak Demand:	
October - May	$12.25 per Kw
June - September	$15.25 per Kw
On-Peak Energy:	
For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.	1.607¢ per Kwh
Off-Peak Energy:	
For all energy not covered by the On-Peak rating period.	1.357¢ per Kwh
Secondary Service:	
Basic Service Charge:	$72.00 per month
On-Peak Demand:	
October – May	$10.75 per Kw
June – September	$14.75 per Kw

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.	2.512¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.	2.262¢ per Kwh

Minimum Bill:
Basic Service Charge.

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

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Determination of On-Peak Billing Demand:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month defined as 12:00 p.m. to 8:00 p.m. local time, Monday through Friday. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day General Electric Service rate or returning to the regular General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 32

Availability:

In all communities served for space heating service, where the customer also takes service under another general service rate schedule offered by the Company. Space heating equipment, including combination space heating and cooling equipment such as heat pumps and packaged roof-top heating/cooling units where heating use is the principal load may be served under this rate schedule.

Rate:

Basic Service Charge:	$21.00 per month
Primary Service:	
Demand Charge:	
October – May	$ 1.00 per Kw
June – September	$14.00 per Kw
Energy Charge:	1.422¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$ 1.00 per Kw
June – September	$12.50 per Kw
Energy Charge:	2.422¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM SERVICE ECONOMIC DEVELOPMENT Rate 34

Availability:

In all communities served for all types of general electric service which meets one of the following qualifications:

1. New Customers - An applicant with total expected demand of 200 Kw per month and usage of 750,000 Kwh per year is eligible for service under this rate if it can meet any one of the following requirements: (i) its activities are largely or entirely different than that of the previous customer; (ii) that non-seasonal business has not been conducted at the premise for at least three billing periods prior to the application; (iii) that seasonal business has not been conducted at the premise for at least thirteen billing periods prior to the application; or (iv) the facility is newly constructed.

2. Existing Customers and Existing In-state Customers of Competing Suppliers - An existing customer, or an existing in-state customer of a competing supplier with increased demand of 200 Kw per month and increased usage of 750,000 Kwh per year is eligible for service under this rate. Only the expanded portion of the facility will be eligible for the negotiated rate. In addition, the new load must be supplied from a separately metered circuit with separate metering equipment to be installed at the customer's expense. Average usage at the original facility must be at least as great as that which occurred in the previous 12 month period.

Rate:

Basic Service Charge:	$100.00 per month
Demand Charge:	To Be Negotiated
Energy Charge:	Otherwise applicable energy charge for General Service Rate 30.

Contracts shall be filed with and approved by the North Dakota Public Service Commission.

Minimum Bill:
Basic Service Charge plus Demand Charge.

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

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Right to Discontinue Service:
The Company reserves the right to refuse applicants who have not previously signed a contract for service under this rate if it determines either system capacity or system energy supply is projected to be insufficient, or if service reliability is expected to be at jeopardy.

Determination of Billing Demand:
The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 200 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

General Terms and Conditions:

1. The customer and the Company shall execute a contract for service to be effective under this rate for a period of five years from the date of service commencement.

2. The negotiated demand charge shall be increased according to the differential between the negotiated rate and the ceiling as portrayed by the following schedule.

Years	Differential Percent Decrease
1-3	0%
4	25%
5	50%

   At the end of the fifth year, the negotiated agreement hereunder expires.

3. Upon expiration of the contract, the customer shall be served under the otherwise applicable rate schedule.

4. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

Availability:

In all communities served for power to customers having a demand of 500 Kw or more for its interruptible load available for interruption for up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a separately metered circuit at the same voltage and phase utilized to serve the balance of the customer's electrical load so arranged to allow remote operation by the Company.

Type of Service:

Service under this rate shall be taken by the customer at whatever primary voltage is available at the point of delivery but not less than 2,400 volts. In the event that it is necessary to build a substation on the Company's transmission line to serve the customer, the cost of building the substation shall be a matter of negotiation between the Company and the customer.

Rate:

Basic Service Charge:	Specified in the electric service agreement with the Company.
Demand Charge:	
October – May	$ 8.00 per Kw
June – September	$11.00 per Kw
Energy Charge:	1.252¢ per Kwh

Minimum Bill:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. The customer shall execute an electric service agreement with the Company which will include, among other provisions, a minimum term of service and monthly Basic Service Charge payments to the Company. The monthly Basic Service Charge payments are determined on a customer by customer basis and shall include, but are not limited to, any additional costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate.

2. All equipment associated with the interruptible load must be of such voltage and electrical characteristics that it can be separately metered and served from the circuit provided for the interruptible portion of the customer's load. If the equipment to be served is such that this is impossible, the customer must either make special arrangements with the Company or furnish the necessary equipment suitable for connection and metering to the circuit for the interruptible portion of the load.

3. The customer must provide a load-break switch or circuit breaker equipped with electrical trip and close circuits allowing for remote operation of the customer's switch or circuit breaker by the Company. Customer must wire the trip and close circuits into a connection point designated by the Company to allow installation of control equipment by the Company. Customer must provide a continuous 120 volt AC power source at the connection point for operation of the Company's control system.

4. The Company may request the customer to interrupt at any time for up to 100 hours during an annual period starting with the in-service date of the contract between the Company and the customer and annually thereafter. Company shall reimburse customer for customer's fuel when interrupted at a mutually acceptable level and price.

5. Customer will be required to interrupt service within 10 minutes of the Company's signal to interrupt service.

6. The penalty for non-performance when the Company requests the customer to interrupt will be the greater of $10.00 per Kw applicable to the Kw demand specified in the electric service agreement with the Company or the appropriate allocation of any penalties imposed on the Company by the Midwest Reliability Organization for the period of non-performance. After a second failure to perform, within a 12-month period, the customer shall be liable for the penalty and may be moved to the otherwise applicable rate.

7. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

8. The foregoing schedule is subject to Rates 100-112 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

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

State of North Dakota
Electric Rate Schedule

SMALL MUNICIPAL ELECTRIC SERVICE
Rate 40 (CLOSED)

Availability:

For all lighting and power requirements with billing demands of 50 kilowatts or less for public buildings or locations supported by public tax levies, and for which the city is liable for payment, in all municipalities served where the Company is operating under a municipal franchise or permit, and the municipality has a standard contract for operation of a street lighting system and/or a municipal pumping system with the Company.

This rate is restricted to small municipal electric service customers who were served under this rate prior to January 27, 1987. Any new small municipal general electric service customer may take service under another applicable rate.

Rate:

Non-Demand:

Basic Service Charge:	$0.84 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	3.402¢ per Kwh
Over 750 Kwh per month	2.302¢ per Kwh
June – September:	3.402¢ per Kwh

Demand:

Basic Service Charge:	$1.00 per day
Demand Charge:	
October – May:	
10 Kw or less	No Charge
Over 10 Kw	$ 8.25 per Kw
June – September:	$11.25 per Kw
Energy Charge:	1.302¢ per Kwh

Date Filed: October 8, 2018
Effective Date: Service rendered on and after December 1, 2018
Issued By: Tamie A. Aberle, Director - Regulatory Affairs
Case No.: PU-18-89

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under the non-demand rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Customers not qualifying for the non-demand rate shall be served under the demand rate.

4. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

MUNICIPAL LIGHTING SERVICE Rate 41

Availability:

For municipal lighting purposes including streets, alleys and other public grounds. Service will be provided all night, every night in the year with a minimum service requirement of 4,000 hours annually and must be covered by written contract.

Rate:

Primary Service:

Energy Charge:	5.096¢ per Kwh

Secondary Service:

Energy Charge:	5.596¢ per Kwh

Discount: For contracts of ten years or more 10%

Kwh shall be computed according to the total rated capacity of lamps in use.

Minimum Bill:

As provided in contract.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. The Company will maintain the facilities and change the light bulbs when notified by the municipality that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of employees of the municipality. In case of vandalism, malicious mischief, or willful negligence the Company will charge the municipality for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. In municipally-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

4. When service is not metered, the bill shall be computed on an annual basis, utilizing the minimum service requirement of 4,000 hours annually, and one-twelfth shall be payable each month.

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of North Dakota
Electric Rate Schedule

MUNICIPAL PUMPING SERVICE Rate 48

Availability:

For municipal pumping purposes provided the municipality uses electricity exclusively for all its pumping requirements and purchases all such electricity from the Company. The municipality must sign a contract for a minimum period of one year.

Rate:

Primary Service:

Basic Service Charge: $80.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$6.00 per Kw
June – September:	$9.00 per Kw

Energy Charge: 1.798¢ per Kwh

Secondary Service:

Basic Service Charge: $45.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$6.00 per Kw
June – September:	$9.00 per Kw

Energy Charge: 1.898¢ per Kwh

Discount: For contracts of ten years or more 10%

Minimum Bill:

Basic Service Charge plus Demand Charge.

Payment:

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

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

2. The foregoing schedule is subject to Rates 100-112 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

OUTDOOR LIGHTING SERVICE Rate 52

Availability:

For all outdoor lighting including flood lights, billboard lighting, metallic vapor yard lights, and Christmas lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

Rate:

Primary Service:	
Energy Charge:	6.357¢ per Kwh
Secondary Service:	
Energy Charge:	6.763¢ per Kwh

Kwh shall be computed according to the total rated capacity of the units in use.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Applicable to Company-owned Facilities:
   a. The Company will install, own and operate the flood light(s), and yard light(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

b. The light may be mounted on existing poles owned or controlled by the Company. The Company will furnish a 35 foot pole(s) for flood lights and a 30 foot pole(s) for yard light(s) at the customer's request at a separate rental rate if a special setting is required. If the customer chooses, the light may be installed on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

c. To the rate stated herein, bulb replacement and ownership costs for the units shall be added. The customer should consult with the Company for such costs.

d. The Company will maintain the facilities and change the light bulbs when notified by the customer that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of the customer. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. When service is not metered, the bill shall be computed on an annual basis, utilizing the minimum service requirement of 4,000 hours annually, and one-twelfth shall be payable each month.

   Metallic vapor ratings in lumens shall be converted to watts on the basis of the published ratings currently issued by the General Electric Company and the Westinghouse Electric Corporation.

4. The foregoing schedule is subject to Rates 100-112 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

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

State of North Dakota
Electric Rate Schedule

Renewable Resource Cost Adjustment Rate 55

1. Applicability:

This rate schedule represents a Renewable Resource Cost Adjustment (RRCA) and specifies the procedure to be utilized to recover the jurisdictional costs associated with renewable generation resource modifications or additions approved by the Commission, but not recovered through retail rates. Costs to be recovered may include operation and maintenance expenditures, depreciation, taxes, and a current return on the project costs.

2. Renewable Resource Cost Adjustment:

a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the RRCA rates. The return component of the revenue requirement calculation will include the return on equity established in the Company's most recent rate case.
b. The RRCA is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express RRCA applicability, and are allocated amongst the rate classes based on the Company's Demand/Energy Factor No. 3 established in the Company's most recent general rate case.
c. The RRCA will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.
d. A true-up will reflect any over or under collection of revenue under the RRCA based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. Renewable Resource Cost Adjustment:

Residential & Small General	0.899¢ per Kwh
Large General	0.838¢ per Kwh
Lighting	1.161¢ per Kwh

Reserved for Future Use

Generation Resource Recovery Rider Rate 56

Applicability:
This rate schedule represents a Generation Resource Recovery Rider (GRRR) and specifies the procedure to be utilized to recover the jurisdictional costs associated with generation resource additions approved by the Commission but not recovered through retail rates and financial incentives for power purchase agreement eligible for recovery under NDCC 49-06-02 subpart 4. Costs to be recovered may include operations and maintenance expenditures, depreciation, taxes, power purchase agreement financial incentives, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

1. Generation Resource Recovery Rider:

a. The North Dakota jurisdictional GRRR revenue requirement will be allocated to the customer classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case. The adjustment applied to the Residential, Small General Service and Lighting Classes will be calculated based on the customer class revenue requirement and the forecasted Kwh for the forecasted period. The adjustment applied to the Large General Service Class will be calculated based on the customer class revenue requirement and the forecasted demand for the forecasted period and expressed as a KW charge. The return component of the revenue requirement calculation will include the authorized return on equity specified in Case No. PU-16-666.
b. The GRRR is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express GRRR applicability, and are allocated amongst the rate classes based on the applicable demand factor.
c. The GRRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.
d. A true-up will reflect any over or under collection of revenue under the GRRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

2. Generation Resource Recovery Rider:

Residential & Small General	0.185¢ per Kwh
Large General	54.680¢ per KW
General Space Heating Rate 32	23.976¢ per KW
Lighting	0.091¢ per Kwh

Environmental Cost Recovery Rider Rate 57

1. **Applicability:**
This rate schedule represents an Environmental Cost Recovery Rider (ECRR) and specifies the procedure to be utilized to recover the jurisdictional costs to be incurred by the Company in complying with federal and state environmental mandates determined to be eligible for recovery under NDCC 49-05-04.2. Costs to be recovered may include capital expenditures, depreciation, taxes, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

2. **Environmental Cost Recovery Rider:**
   a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the ECRR. The return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case.
   b. The ECRR is applicable to all retail customers for electric energy sold, except those served under special contracts, and are allocated amongst the rate classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case.
   c. The ECRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be eligible under NDCC 49-05-04.2.
   d. A true-up will reflect any over or under collection of revenue under the ECRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Environmental Cost Recovery Rider:**

Residential and Small General	0.000¢ per Kwh
Large General	0.000¢ per Kwh
Lighting	0.000¢ per Kwh

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

State of North Dakota
Electric Rate Schedule

Reserved for Future Use

FUEL AND PURCHASED POWER ADJUSTMENT Rate 58

1. **Applicability:**
   This rate schedule sets forth the procedure to be used in calculating the Fuel and Purchased Power Adjustment (FPPA). It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power as allocated to North Dakota; and (b) amortization of the Deferred Fuel Cost Account.

2. **Effective Date and Limitation on Adjustments:**
   a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Purchased Power Adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Deferred Fuel Cost Account shall be April 1 of each year.

   b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of electric supply only when the amount of change in such adjustment is at least .001 cents per Kwh. The adjustment to be effective April 1 shall be filed each year, regardless of the amount of the change.

3. **Fuel and Purchased Power Adjustment:**
   a. The monthly Fuel and Purchased Power Adjustment shall be calculated separately for primary service and secondary service customers and shall reflect Montana-Dakota's cost of fuel and purchased power plus the annual Surcharge Adjustment.

   b. The cost of fuel and purchased power shall be calculated separately for primary service customers and secondary service customers, and shall be the sum of the following costs for the most recent four month period, as allocated to North Dakota and to the primary and secondary customer classes:

      1. The cost of fossil and other fuels and reagents, including sand, recorded in Account Nos. 501, 502 and 547.

2. Natural gas and pipeline reservation charges recorded in Account No. 547
3. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in the wholesale electric energy markets as recorded in Account No. 555
4. Capacity purchases as recorded in Account No. 555.
5. Regional Market Administration expenses recorded in Account No. 575.
6. Less 100 percent of the wholesale sales revenue.
7. Less the revenue from the sales of Renewable Energy Credits (RECs).

c. The cost per Kwh for the month is the sum of 3(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes.

4. Surcharge Adjustment:
All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on April 1 each year. The Surcharge Adjustment per Kwh sold shall reflect the amortization of the applicable balance in the Deferred Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

a. The balance in the Deferred Fuel Cost Account (Account 182.3) includes:

1. The current month over or under recovery, determined as follows:

   i. Montana-Dakota shall determine each month the cost for that month's fuel and purchased power.

   ii. Montana-Dakota shall subtract from the month's cost determined in 4.a.1.i the revenue collected under the Fuel and Purchased Power Adjustment for that month.

iii. The resulting difference (positive or negative) shall be included separately for primary and secondary service classes.

2. Refunds from supplier(s) and market operators with respect to fuel and purchased power costs.

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

5. Manner of Filing:
The Company shall file a monthly statement showing the calculation of the Fuel and Purchased Power Adjustment with the Commission prior to implementing the monthly adjustment. The adjustment in rates shall be effective with service rendered on and after the first day of each month, unless the Commission shall otherwise order.

6. Fuel and Purchased Power Adjustment:
The current and historical Fuel and Purchased Power Adjustment for primary and secondary service customers can be found at www.montana-dakota.com/rates-and-services.

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TRANSMISSION COST ADJUSTMENT Rate 59

1. **Applicability:**
This rate schedule represents a Transmission Cost Adjustment (TCA) and specifies the procedure to be utilized to recover the net balance of the capital and operating costs and revenue credits of Montana-Dakota's transmission related expenses and revenues determined to be eligible for recovery in accordance with 49-05-04.3 NDCC. Costs to be recovered under the Transmission Adjustment shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

2. **Transmission Cost Adjustment:**
   a. An adjustment per Kwh will be determined based on the cumulative transmission related costs and revenue credits eligible for recovery and as allocated to the North Dakota jurisdiction and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

   b. The adjustment will be applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express TCA applicability, and allocated among the rate classes based on the transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case.

   c. The adjustment per Kwh will be revised annually to reflect the current level of costs to be recovered.

d. The true-up will reflect any over or under collection of revenue under the Transmission Adjustment from the preceding twelve month period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. Transmission Cost Adjustment Rate by class:

Residential & Small General	0.801¢ per Kwh
Large General	0.636¢ per Kwh
Lighting	0.360¢ per Kwh

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

State of North Dakota
Electric Rate Schedule

OCCASIONAL POWER PURCHASE Rate 95
NON-TIME DIFFERENTIATED

Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating occasional electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 100 Kw or less, that are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$0.05 per day
With instrument transformers:	$0.19 per day
Metering charge for three phase service:	$0.12 per day
With instrument transformers:	$0.33 per day

Energy delivered to and accepted by Company by a QF shall be paid for by Company in accordance with one of the following two options, elected by the QF:

1. Simultaneous Purchase and Sale:
   Energy sales to QF - Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

   Energy purchases by Company:

   Energy Payment = 2.145¢ per Kwh

2. Net Billing:
   Energy generated will be compensated on a net billing basis. The Company will install a meter to measure the energy generated by the QF. The Company will also install a meter to measure the energy consumed by the QF. Metered generation will be subtracted from the metered consumption for the billing period.

Date Filed:	October 13, 2021	**Effective Date:**	Service rendered on and after January 1, 2022
Issued By:	Travis R. Jacobson Director of Regulatory Affairs	**Case No.:**	PU-21-404

If metered generation is less than metered consumption, the QF will be billed the applicable retail rate. If metered generation is greater than the metered consumption, the QF will be paid for each Kwh at an amount equal to:

2.145¢ per Kwh

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.

2. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

3. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

4. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be at least one year but less than five years.

5. In order to qualify for the net billing option, the generating equipment and the load of the facility must be located at the same "physical site". "Physical site" shall mean on the same tract of land and the generator output must be physically connected to the load service entrance.

6. For general terms and conditions covering QF's, see Rate 140.

7. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

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Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 1000 Kw or less, that operate as a peaking facility (defined below), and are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$ 0.16 per day
With instrument transformers:	$ 0.30 per day
Metering charge for three phase service:	$ 0.18 per day
With instrument transformers:	$ 0.38 per day

1. Capacity delivered to the Company:

   Monthly capacity payments for a QF (not registered as a MISO generator) shall be assigned by Montana-Dakota based upon the amount of qualifying capacity assigned to an eligible resource under BPM-011 Resource Adequacy of the MISO tariff subject to adjustment annually in accordance with BPM-011.

   Monthly capacity payments for a MISO-registered QF shall be based on the capacity credits assigned by MISO on an annual basis.

   Monthly capacity payment shall be the MISO capacity auction clearing price for Zone 1. The capacity payment is subject to change annually through the year 2030. Effective in 2031 the monthly capacity payment shall be $9.655 per Kw applicable for the remainder of the term of the contact.

   Capacity payments will be paid in the subsequent billing period.

2. Energy Payment:

	ON-PEAK	OFF-PEAK
	2.072¢ per Kwh	2.139¢ per Kwh

Peak Periods: The On-Peak Period is defined as those hours between 12 p.m. and 8 p.m. local time, Monday through Friday in the months of June through September. The Off-Peak Period is defined as all other hours. Definitions of On-Peak and Off-Peak periods are subject to change with change in the Company's system operating characteristics.

Energy Sales to Qualifying Facilities:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.

2. Service under this schedule shall be on a simultaneous purchase and sale basis only.

3. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

4. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

5. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be five years or more.

6. Line loss considerations will be determined on a site specific basis.

7. For dispatchable units, generator outages must be pre-scheduled with Company to provide coordination with Company units.

8. A Peaking Unit is a unit not designed for continuous operation and is capable of supplying capacity and energy during periods of peak electric consumption. Generally, peaking units have a capacity factor of 20% or less.

9. For general terms and conditions covering QF's, see Rate 140.

10. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

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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 (Commission) 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. Also refer to Electric Service Rules & Regulations Rate 110.

II. DEFINITIONS:

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

APPLICANT – A customer requesting Company to provide service.

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

COMPANY – Montana-Dakota Utilities Co.

CUSTOMER – Any individual, partnership, corporation, firm or 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.

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.

III. GENERAL TERMS AND CONDITIONS:

1. RULES FOR APPLICATION OF ELECTRIC SERVICE:
   i. Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

      a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate. Where premise is defined as a contiguous parcel of land undivided by a dedicated street, alley, highway, or other public thoroughfare or railway.

      b. Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

      c. Only single phase service is available under the Residential Electric Service Rate.

   ii. Three phase service shall be served under the appropriate General Electric Service Rate.

   iii. General Electric Service is defined as service provided to non-residential services, such as 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 parlors, apartment houses with master metering exemptions, 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).

iv. If separate metering is not practical for a single unit (one premise) that is using electricity for both domestic purposes and for conducting business (or for nonresidential purposes), 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 General Electric Service) applicable to the type of service which constitutes 50% or more of the total connected load.

v. 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 appropriate General Electric Service Rate.

2. CONSUMER DEPOSITS:
The Company will determine whether or not a deposit shall be required of an applicant for electric service in accordance with Commission rules.

   i. The amount of such deposit shall not exceed an estimated 60 day service bill.

   ii. 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 or 30

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.

iii. 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.

iv. Deposits shall be refunded to customers at termination provided all billings for service have been paid. Deposits will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record has been established.

3. LATE PAYMENT CHARGE:
Bills will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any past due balance.

4. 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.

5. TAX CLAUSE:
In addition to the charges provided for in the electric 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.

6. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS:
   For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

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

7. RECONNECTION FEE FOR SEASONAL CUSTOMERS:
   A charge will be collected for reconnecting electric service to a customer who requests reconnection of service, at a location where the same customer discontinued the same service during the preceding twelve-month period.

   Applicable Charge:

   i. Customers with non-demand meters: $20.00

   ii. Customers with demand meters: $40.00

8. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILL:
   i. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(1), the Company may disconnect service if the customer is delinquent in payment for service, and fails to pay for service or enter into a satisfactory installment agreement with the Company for payment within ten (10) days of the Company giving the customer written notice of the Company's intention to discontinue service on account of payment delinquency.

   ii. All bills for service are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of service bills, such service may be discontinued by the Company under the applicable rules of the Commission.

iii. If a customer's credit standing becomes unsatisfactory after a deposit has been refunded or if the deposit is inadequate to cover the estimated charge for furnishing service for a 60-day period, a new or additional deposit may be required upon reasonable written notice by the Company.

iv. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(10), the Company may not discontinue service to the Customer for nonpayment of a deposit.

v. The Company may collect a fee of $20.00 before restoring electric service which has been discontinued for nonpayment of service bills, or where a Service Extender has been installed in lieu of full disconnection.

9. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS:
The Company reserves the right to discontinue service for any of the following reasons:

i. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

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

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

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

v. 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 $20.00 before restoring electric service, which has been disconnected for the above causes.

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

11. METHOD OF COMPUTING INITIAL OR FINAL BILLS FOR ELECTRIC SERVICE FOR LESS THAN A FULL MONTHLY BILLING PERIOD:
Customer's meters are read as nearly as practicable at thirty day intervals. When service is begun or terminated at any location between regular meter reading dates, bills will be prorated on a daily basis, whenever the billing period is less than 27 calendar days or more than 35 calendar days. The minimum monthly bill, basic service charge, kilowatt hour blocks and demand charge provisions in all rate schedules will be prorated.

12. SELECTIVE TESTING PLAN FOR METERS:
The electric meter population shall be tested in accordance with the Electric Meter Testing Program approved by the Commission.

13. BILLING ADJUSTMENTS:
If a meter or billing error results from 1) an inaccurate meter; 2) an Incorrect reading of the meter; 3) an incorrect application of a rate schedule; 4) an incorrect connection of the meter; 5) an application of an incorrect multiplier or constant; or 6) other similar errors affecting customer bills.

    i. If a Customer is underbilled, the Company may recalculate the bills and reissue corrected bills for service during the period of the error, up to a maximum period of six years from the date of the bill, with the exception of a meter equipment failure.

    ii. If a Customer is overbilled, the Company shall recalculate bills for errors resulting in overcharges up to a maximum of six years from the date of payment, with the exception of a meter equipment failure. In the case of a meter equipment failure, the Company may charge the Customer for a period equal to one-half the time elapsed since the last previous meter test, but not to exceed six months.

14. MODIFICATION OF RATES, RULES AND REGULATIONS:
Company reserves the right to modify its rates, rules, and regulations or other provisions now or hereafter in effect, in any manner permitted by law.

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

State of North Dakota
Electric Rate Schedule

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MONTANA-DAKOTA UTILITIES CO.

ELECTRIC SERVICE
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ILLUSTRATIONS

101. Definitions

Company – Montana-Dakota Utilities Co.

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

102. Purpose

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other generally 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 Regulatory Commissions 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.

103. Customer Obligation

103.1 Application for Service – A customer desiring electric service must submit an 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 service 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 electric service 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 electric service until notified by the 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 necessary.

103.2 Access to Customer's Premises – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

103.3 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.

103.4 Relocated Facilities – Where Company facilities are located on or adjacent to a customer's premises where there is an encroachment(s) to electric facilities the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

103.5 Notification of Unsafe Conditions – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

103.6 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.

<u>104. Liability</u>
104.1 Continuity of Service – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

104.2 Customer's Equipment – Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed 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, leased by the customer from third parties or used on the customers premise. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

104.3 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 electricity 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.

104.4 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.

104.5 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.

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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or 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.

105. Electrical Codes and Ordinances

The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

106. Wiring Adequacy

Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

107. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

108. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 107 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

109. Consultation with the Company
109.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

109.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

109.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

110. Unauthorized Use of Service
110.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

110.2 Types of unauthorized use of service include, but are not limited to, the following:
- (a) Bypass around meter.
- (b) Meter reversed.
- (c) Equipment connected ahead of meter.

(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

110.3 In the event that there has been unauthorized use of service, customer shall be charged for:
(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

110.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any charges which are due, including:
(a) All delinquent bills, if any;
(b) The amount of any Company revenue loss attributable to said tampering;
(c) Expenses incurred by the Company in replacing or repairing the meter or other equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 110.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with rules of the applicable State Public Service or Utilities Commission.

111. Unauthorized Attachments to Poles

111.1 The unauthorized attachment of any flags, banners, signs, clotheslines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

111.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules
Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy
The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service
Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service
Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer’s expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service
Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on the Customer's Premises

206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company’s power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer’s expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

207. Overhead to Underground Primary Conversion
When requested by property owners, underground distribution and services will be provided to replace existing overhead distribution to a group of owners cooperating with one another, providing:

(a) There exists a sufficient number (25) of homes on contiguous lots that are available for the conversion. At the Company's option, smaller groups could be acceptable.
(b) The terrain and other soil conditions are suitable for installation of underground facilities.
(c) Easements will be granted at no cost to the Company, wherever installed facilities are on private land.
(d) The customer, at customer's expense, must adapt the customer's electrical facilities to accept an underground service.
(e) The customer, or group of customers, provide payment for the cost of removal of overhead facilities and total installed cost, multiplied by the fractional life remaining, less the salvage value of the removed equipment. The customers may also be required to reimburse the company for other reasonable and prudent costs in excess of the Company's standard installation that result from the installation of the requested underground distribution.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency
All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400)
302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service
1	3	120/240	Single Phase Lighting & Power
3	4 Delta	120/240	Combined Light & Power *
3	4 Wye	208 Grd Y/120	Combined Light & Power
3	4 Wye	480 Grd Y/277	Combined Light & Power **
3	4 Delta	240/480	Combined Light & Power *

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 109)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to Paragraphs 103.1, 107, and 108.)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electric Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly

marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops
407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (refer to the National Electrical Safety Code for possible exceptions):

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate at a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:

- (1) 17 feet - where multiplex service drops cross over or run along alleys, driveways, or parking lots.
- (2) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 14 feet - over residential driveways for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:

- (1) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 12 feet - for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electric Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18 inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete driveway, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in approved mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the Customer's particular needs.

502. Service Entrance Equipment

The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection

The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means

504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance

Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 – METERING

601. General

The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes.
It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets – Single-Phase, Three-Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the Company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations.
4. 150 ampere minimum for underground service installations.
5. Stud connectors are required for all sockets rated 320 amps or greater.
6. For sockets rated below 320 amps, study connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
7. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
8. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
9. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weatherproof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.

4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rated meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3.)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into the meter socket.

603. Meter-Switch-Fuse Wiring Sequence
For all secondary voltage metering installations the meter, entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. A customer-owned main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company. (Refer to Figure 1.)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet - 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by customer. (Refer to Figures 1, 2, and 3.)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering

Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams

Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling

Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates

shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals
All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building which contain unmetered wires, shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads
Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at customer's expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics
702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection.

703. Power Factor
Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in

certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment
At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders
Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors
706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to paragraph 702)

706.4 The size of three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

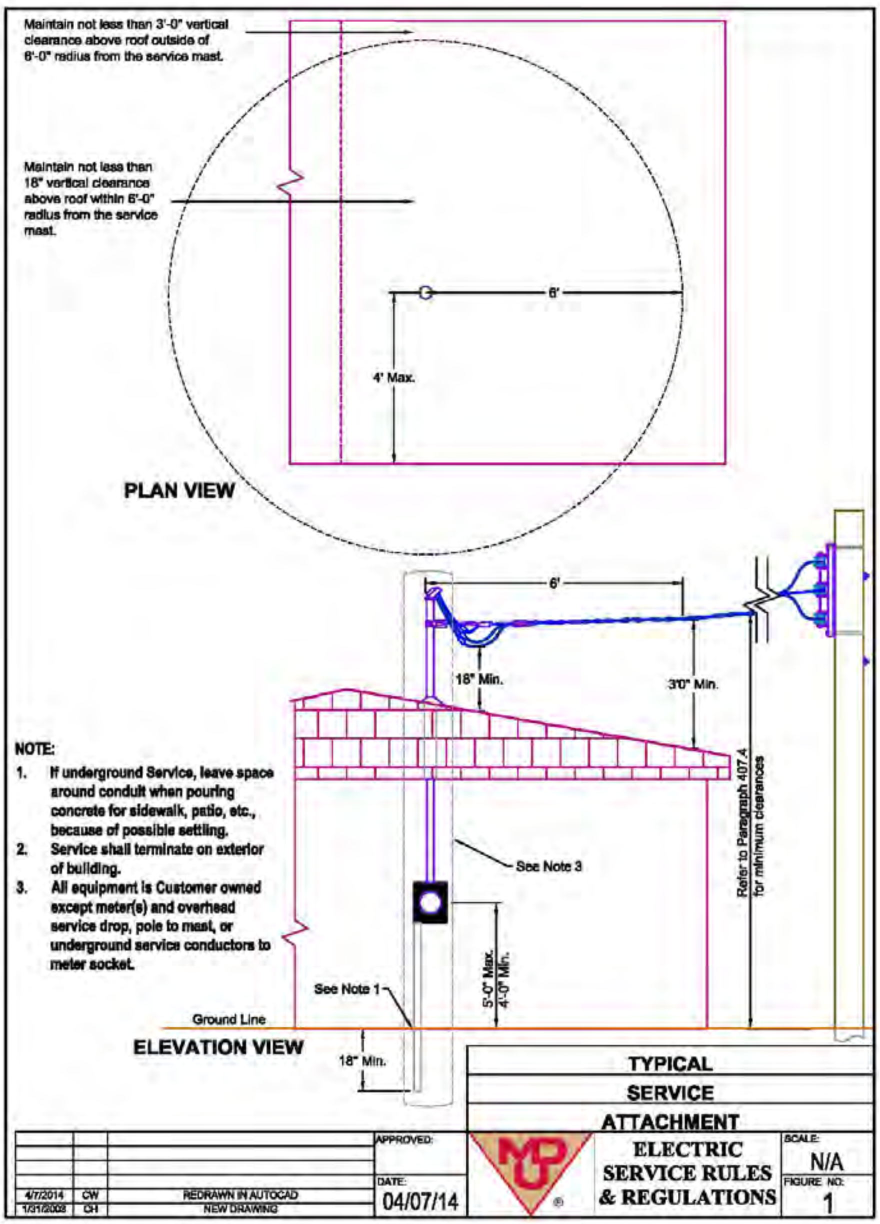
707. Flashing Display Signs
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

708. Fluorescent and Gaseous Tube Lighting
High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

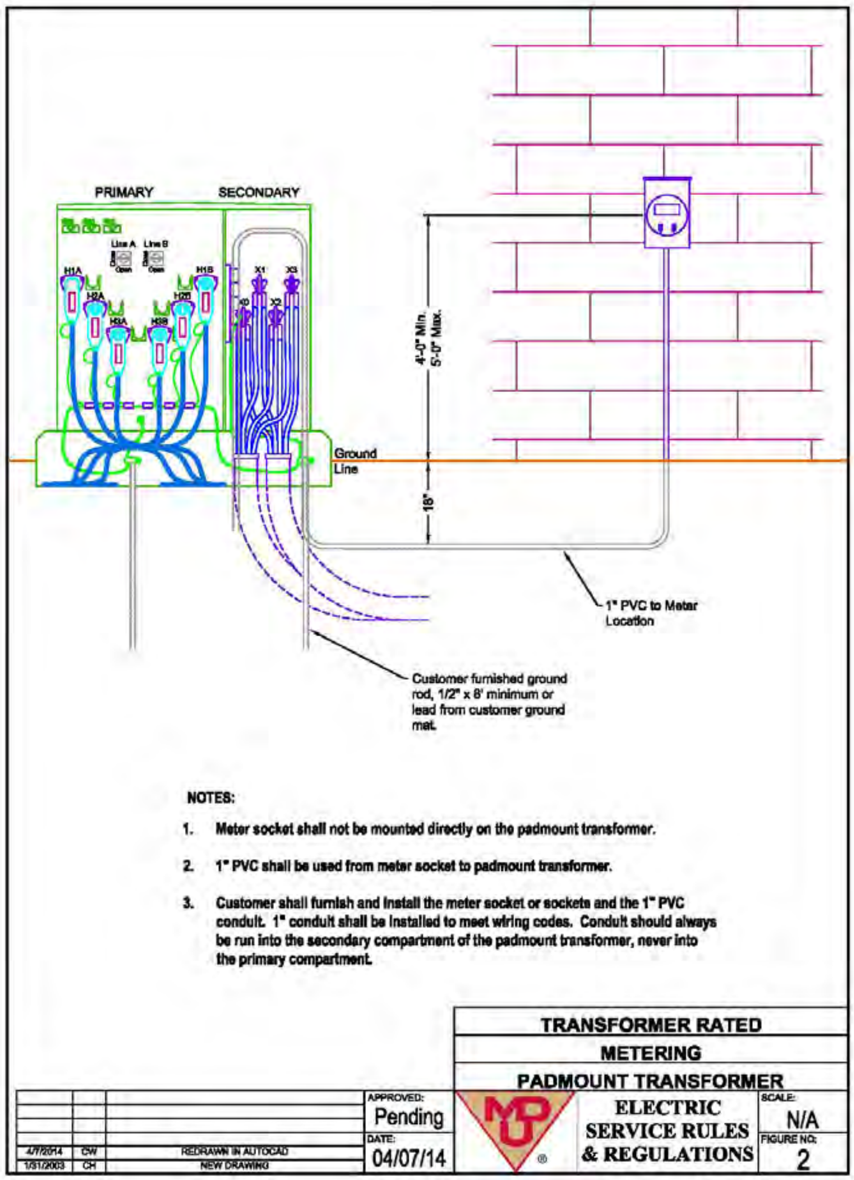
709. Electric Heat Equipment
A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

710. Computers and Electronic Equipment
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to Paragraph 104.2.)

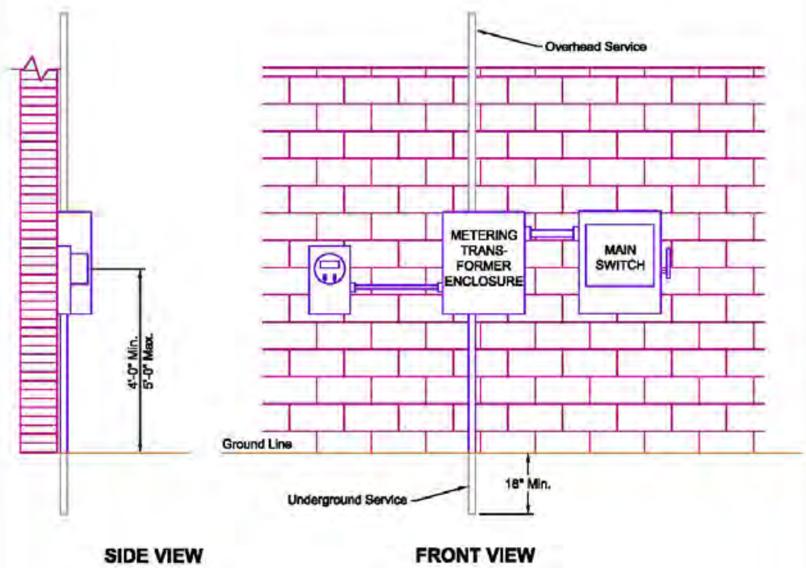
711. Carrier Equipment
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system.



Maintain not less than 3'-0" vertical clearance above roof outside of 6'-0" radius from the service mast.
Maintain not less than 18" vertical clearance above roof within 6'-0" radius from the service mast.
6'
4' Max.
PLAN VIEW
6'
18" Min.
3'0" Min.
NOTE:
1. If underground Service, leave space around conduit when pouring concrete for sidewalk, patio, etc., because of possible settling.
2. Service shall terminate on exterior of building.
3. All equipment is Customer owned except meter(s) and overhead service drop, pole to mast, or underground service conductors to meter socket.
See Note 3
Refer to Paragraph 407.4 for minimum clearances
5'-0" Max.
4'-0" Min.
See Note 1
Ground Line
ELEVATION VIEW
18" Min.
TYPICAL
SERVICE
ATTACHMENT
APPROVED:
DATE:
04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
SCALE:
N/A
FIGURE NO:
1
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2008 CH NEW DRAWING



PRIMARY
SECONDARY
Line A
Line B
H1A
H2A
H3A
H3B
H2B
H1B
X1
X3
X0
X2
4'-0" Min.
5'-0" Max.
Ground Line
18"
1" PVC to Meter Location
Customer furnished ground rod, 1/2" x 8' minimum or lead from customer ground mat.
NOTES:
1. Meter socket shall not be mounted directly on the padmount transformer.
2. 1" PVC shall be used from meter socket to padmount transformer.
3. Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.
TRANSFORMER RATED
METERING
PADMOUNT TRANSFORMER
APPROVED:
Pending
DATE:
04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
SCALE:
N/A
FIGURE NO:
2
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2003 CH NEW DRAWING



NOTE:

1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3. Equipment is to be installed outdoors.

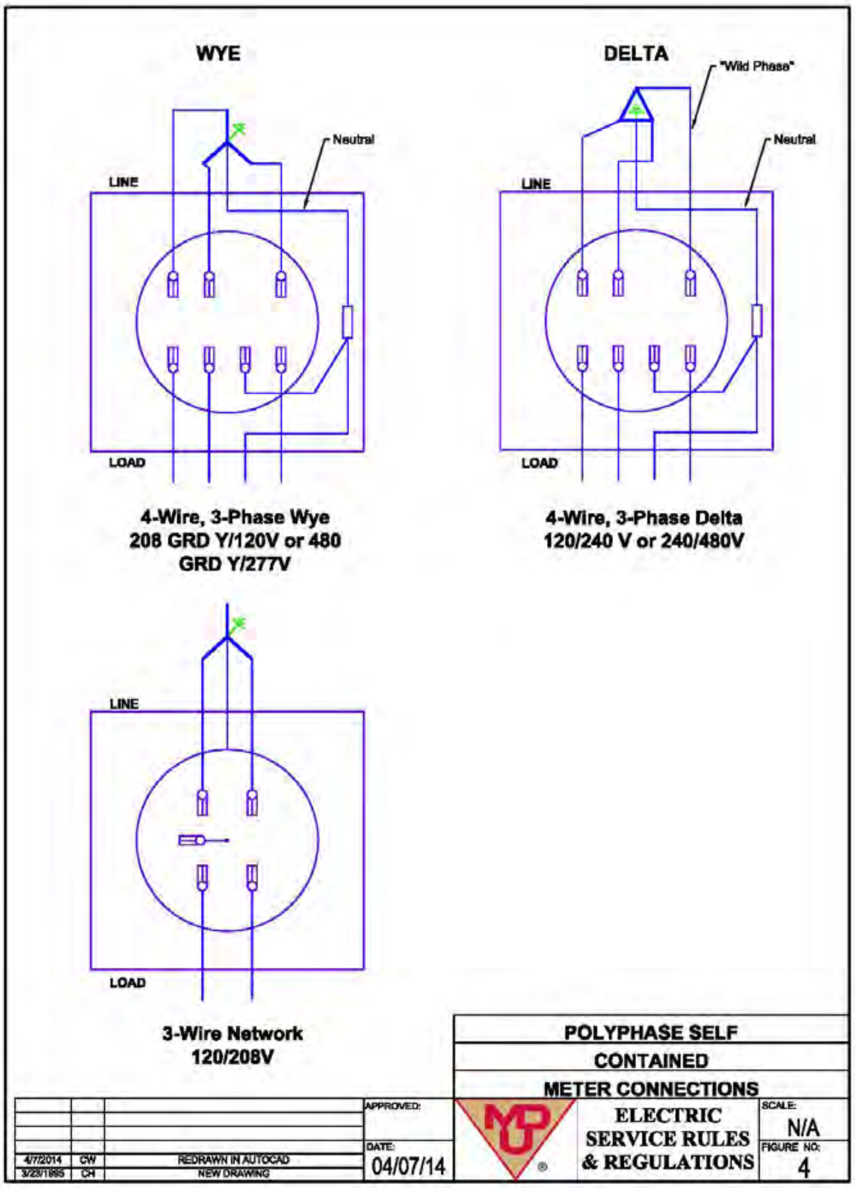
TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE

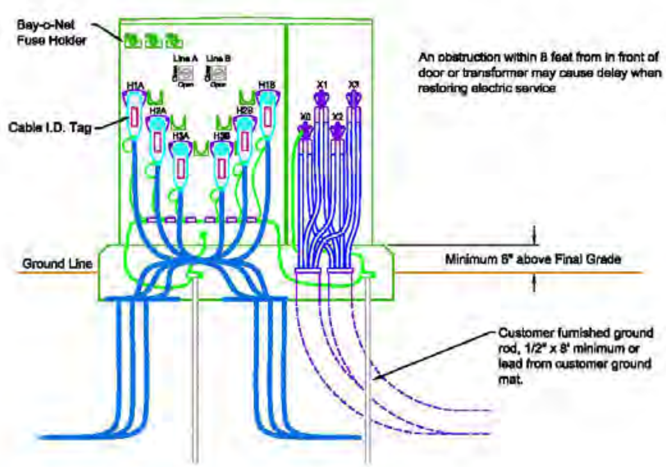
4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED:
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A

FIGURE NO: 3


WYE
DELTA
"Wild Phase"
Neutral
Neutral
LINE
LINE
LOAD
LOAD
4-Wire, 3-Phase Wye
208 GRD Y/120V or 480
GRD Y/277V
4-Wire, 3-Phase Delta
120/240 V or 240/480V
LINE
LOAD
3-Wire Network
120/208V
POLYPHASE SELF
CONTAINED
METER CONNECTIONS
APPROVED:
DATE:
04/07/14
ELECTRIC
SERVICE RULES
& REGULATIONS
SCALE:
N/A
FIGURE NO:
4
4/7/2014 CW REDRAWN IN AUTOCAD
3/28/1995 CH NEW DRAWING



NOTES:

1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

TRANSFORMER LOCATION

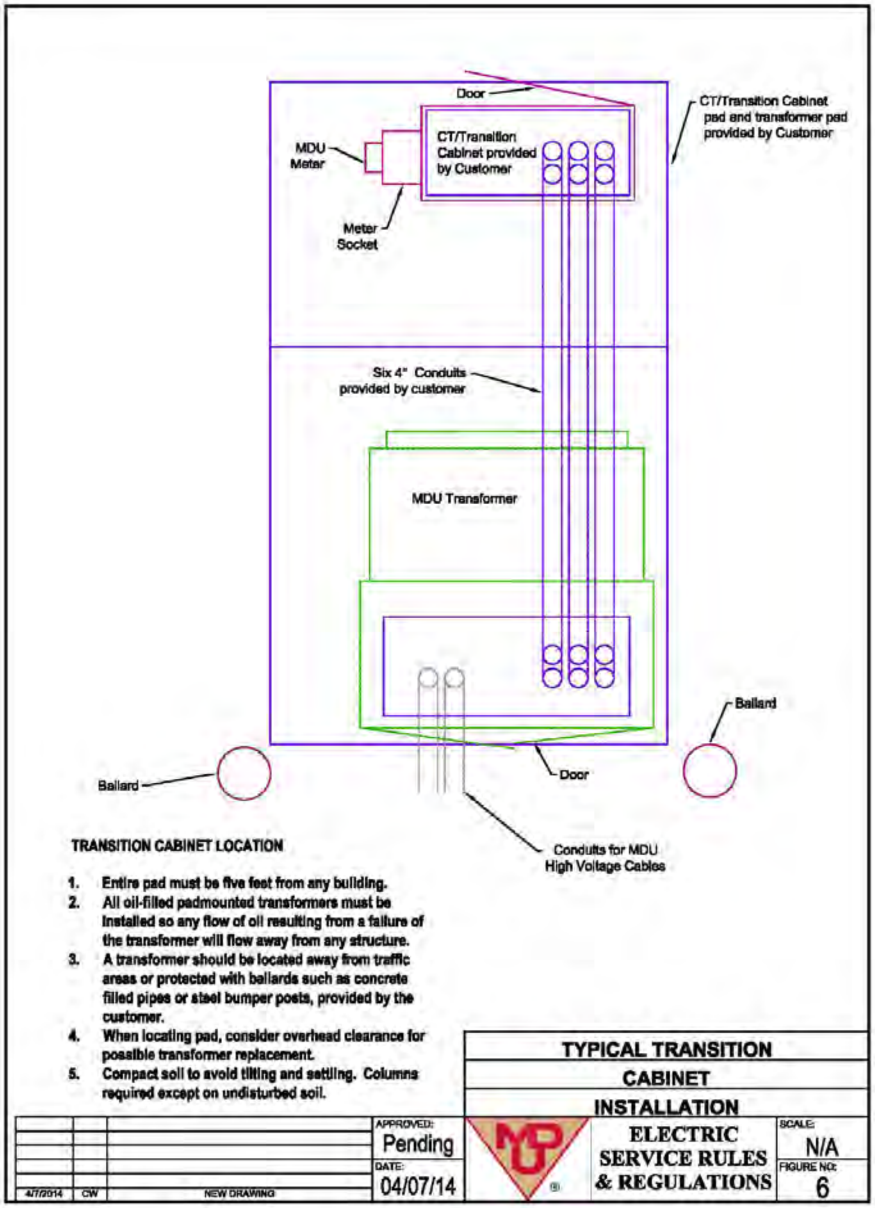
1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with bollards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

TYPICAL PADMOUNT EQUIPMENT INSTALLATION

ELECTRIC SERVICE RULES & REGULATIONS

4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED: Pending
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

SCALE: N/A
FIGURE NO: 5


Door
CT/Transition Cabinet pad and transformer pad provided by Customer
MDU Meter
CT/Transition Cabinet provided by Customer
Meter Socket
Six 4" Conduits provided by customer
MDU Transformer
Ballard
Ballard
Door
Conduits for MDU High Voltage Cables
TRANSITION CABINET LOCATION
1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.
TYPICAL TRANSITION
CABINET
INSTALLATION
APPROVED: Pending
DATE: 04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
SCALE: N/A
FIGURE NO: 6
4/7/2014 CW NEW DRAWING

The policy of Montana-Dakota Utilities Co. for electric extensions to provide service to customers located within its service territory is as follows:

1. A permanent extension may be constructed without a contribution if the estimated project construction cost is equal to or less than two times the estimated annual revenue (2 to 1 ratio).

2. If the estimated project construction cost is greater than two times the estimated annual revenue, the extension will be made only with a contribution, which may be refundable.

   a. Contribution -

      1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the initial contribution shall be the estimated construction cost less two times the estimated annual revenues.

      2) The initial contribution for developers of subdivisions shall be the estimated construction cost.

      3) Payment of the initial contribution amount shall be made prior to construction.

      4) Upon completion of construction, the contribution amount shall be adjusted to reflect actual construction costs and an additional charge or refund levied accordingly.

      5) Company may waive all contributions if it determines that the initial contribution will be soon refunded because of additional customer connections.

b. Refund -

1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above referred to extension, Company shall recompute the contribution required by combining the estimated proposed construction cost for the new customer(s) with the construction cost to those customers already taking service. If, by so combining the construction costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

2) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

3) No refund shall be made by Company to customer(s) or developer after a five-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

4) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction.

3. Project construction cost shall include all cost of the electric extension and overhead cost less the cost of customers' transformer(s), service line, and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

4. Electric extension refers to any facilities which must be constructed to connect a new customer to the utility system or the addition of capacity to existing facilities.

5. Company will deliver electricity to customer at the rate approved by the North Dakota Public Service Commission.

6. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

7. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

8. This rule shall not be construed as prohibiting the Company from making a contract with a customer in a different manner, if the contract provides a more favorable method of extension to the customer. Such determination to be made on the basis of specific extension characteristics.

9. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

Reserved for future use

Reserved for future use

Reserved for future use

Reserved for future use

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

State of North Dakota
Electric Rate Schedule

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

A. NEW METERS

A sampling of 5% will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

B. RESIDENTIAL WATTHOUR METERS IN SERVICE

1. A random selection of meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979, 1980 to 1989, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

C. COMMERCIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

D. INDUSTRIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than ±2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

4. Whenever it is found that less than 99% of the tested meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

Reserved for future use

Reserved for future use

SMALL QUALIFYING FACILITIES (SQF)
GENERAL RULES Rate 140

General Rules for Generation:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This does not affect the responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is de-energized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used, whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights are to be furnished by the owner of the qualifying facility on owner's property.

13. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

14. If the qualifying facility is located at a site outside of Company service territory and energy is delivered to Company through facilities owned by another utility, energy payments will be adjusted reflecting losses occurring between point of metering and point of delivery.

15. In the event the qualifying facility desires wheeling by the Company of its output, arrangements will be made subject to negotiation.

16. A Metering Charge will be assessed the qualifying facility for installation by the Company of additional metering equipment plus operation and maintenance costs.

17. An Interconnection Charge will be assessed for any additional facilities (exclusive of the items included in Metering Charge) or changes in existing facilities to permit interconnection with the Company. Payment shall be a one-time payment.

18. The owner of a qualifying facility will indemnify and save the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

19. Qualifying facilities shall be required to execute a contract that specifies a one or five-year minimum term depending upon applicable rate schedule and describes the responsibilities, liabilities, ownership of equipment, and location.

20. The owner of a qualifying facility shall obtain and maintain general liability insurance in an amount established by negotiation between the owner of a qualifying facility and the Company.

21. Qualifying facilities with generating capacity greater than 1000 Kw, or operating as a base loaded unit regardless of size, will require individual negotiation.

Montana-Dakota Utilities Co.
North Dakota Electric Tariffs - Proposed

Appendix B

TABLE OF CONTENTS

TABLE OF CONTENTS

ELECTRIC SERVICE

Dakota Heartland Region

Almont
Apple Valley
Ashley
Beulah
Bismarck*
Braddock
Burnstad
Carson
Center
Dawson
Driscoll
Elgin
Ellendale
Forbes
Fredonia
Fullerton
Glen Ullin
Golden Valley
Hague
Hazelton
Hazen
Hebron
Heil
Judson
Kintrye
Kulm
Lehr
Leith
Linton
Mandan
McKenzie
Merricourt
Monango
Napoleon
New Leipzig
New Salem
Selfridge
Steele
Sterling
Strasburg
Tappen
Venturia
Wishek
Zap
Zeeland

*Designates Region Office

COMMUNITIES SERVED

ELECTRIC SERVICE

Badlands Region

Alamo
Alexander
Ambrose
Appam
Arnegard
Battleview
Beach
Belfield
Bentley
Bowbells
Bowman
Bucyrus
Burt
Carpio
Columbus
Corinth
Corteau
Coulee
Crosby
Dickinson*
Dodge
Donnybrook
Dunn Center
East Fairview
Epping
Flaxton
Gladstone
Gascoyne
Grenora
Halliday
Hamlet
Hanks
Haynes
Hettinger
Kenmare
Killdeer
Larson
Lemmon
Lignite
Loraine
Marmarth
McGregor
Mohall
Morristown
Mott
New England
Noonan
Norma
Northgate
Portal
Powers Lake
Rawson
Ray
Reeder
Regent
Rhame
Richardton
Ross
Scranton
Sentinel Butte
Sherwood
South Heart
Springbrook
Stanley
Taylor
Tioga
Tolley
Watford City
Werner
Wheelock
Wildrose
Williston
Zahl

*Designates Region Office

RESIDENTIAL ELECTRIC SERVICE Rate 10

Availability:

In all communities served for single-phase residential electric service for domestic purposes only.

Rate:

Basic Service Charge:	$0.67 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	6.512¢ per Kwh
Over 750 Kwh per month	3.512¢ per Kwh
June – September:	6.512¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Availability:

In all communities served for single-phase residential electric for customers operating Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning purposes where electric space heating is the primary heating source. Service under this rate is not available when another energy source provided by the Company is utilized as a back-up heating source.

Rate:

Basic Service Charge:	$1.05 per day
Off-Peak Energy Charge:	
For all energy used during the designated hours of 10:00 p.m. to 8:00 a.m. local time.	
October – May:	1.100¢ per Kwh
On-Peak Energy Charge:	
For all energy not covered by the Off-Peak rating period.	
October – May:	
First 750 Kwh per month	6.512¢ per Kwh
Over 750 Kwh per month	3.512¢ per Kwh
June – September:	6.512¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Thermal storage space heating facilities can include the thermal storage device(s), air-source heat pumps, and associated air handling units.

2. Unless approved by the Company the maximum thermal storage facilities that may be connected under this rate schedule is 50 Kw.

3. The foregoing schedule is subject to Rates 100-112 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
Electric Rate Schedule

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

Availability:

In all communities served for single-phase residential electric service. The customer's wiring must be so arranged that all service can be measured through one meter.

Rate:

Basic Service Charge: $1.05 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	6.395¢ per Kwh
June – September	7.895¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	3.395¢ per Kwh
June – September	4.895¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Residential Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Residential Electric Service rate or returning to the regular Residential Electric Service rate.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

SMALL GENERAL ELECTRIC SERVICE Rate 20

Availability:

In all communities served for all types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be so arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Basic Service Charge:	$1.15 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	6.756¢ per Kwh
Over 750 Kwh per month	3.756¢ per Kwh
June – September:	6.756¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

SMALL GENERAL ELECTRIC SERVICE Rate 20

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Non-metered services. At the Company's discretion, the installation of a meter on a customer's service may not be warranted. In the absence of measuring a customer's use, customers will be billed a predetermined energy use amount each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment served on Company-owned poles.

4. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

IRRIGATION POWER SERVICE Rate 25

Availability:

For irrigation power service.

Rate:

Basic Service Charge:		$1.90 per day
Demand Charge:		
	October – May	$2.74 per Kw
	June – September	$5.74 per Kw
Energy Charge:		0.406¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

Availability:

In all communities served for all types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Basic Service Charge:	$1.30 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	5.043¢ per Kwh
June – September	6.543¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	2.543¢ per Kwh
June – September	4.043¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Small General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Small General Electric Service rate or returning to the regular Small General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SERVICE Rate 30

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Primary Service:	
Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$12.85 per Kw
June – September	$15.85 per Kw
Energy Charge:	1.689¢ per Kwh
Secondary Service:	
Basic Service Charge:	$56.00 per month
Demand Charge:	
October – May	$10.08 per Kw
June – September	$13.08 per Kw
Energy Charge:	2.606¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OPTIONAL TIME-OF-DAY GENERAL
ELECTRIC SERVICE Rate 31

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Primary Service:

Basic Service Charge:	$97.00 per month
On-Peak Demand:	
October - May	$12.96 per Kw
June - September	$15.96 per Kw
On-Peak Energy:	
For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.	1.846¢ per Kwh
Off-Peak Energy:	
For all energy not covered by the On-Peak rating period.	1.596¢ per Kwh

Secondary Service:

Basic Service Charge:	$72.00 per month
On-Peak Demand:	
October – May	$11.43 per Kw
June – September	$15.43 per Kw
On-Peak Energy:	
For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.	2.751¢ per Kwh
Off-Peak Energy:	
For all energy not covered by the On-Peak rating period.	2.501¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Determination of On-Peak Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month defined as 12:00 p.m. to 8:00 p.m. local time, Monday through Friday. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day General Electric Service rate or returning to the regular General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 32

Availability:

In all communities served for space heating service, where the customer also takes service under another general service rate schedule offered by the Company. Space heating equipment, including combination space heating and cooling equipment such as heat pumps and packaged roof-top heating/cooling units where heating use is the principal load may be served under this rate schedule.

Rate:

Basic Service Charge:	$23.00 per month
Primary Service:	
Demand Charge:	
October – May	$ 1.71 per Kw
June – September	$15.85 per Kw
Energy Charge:	1.772¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$ 1.71 per Kw
June – September	$13.08 per Kw
Energy Charge:	2.772¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 32

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

FIRM SERVICE ECONOMIC DEVELOPMENT Rate 34

Availability:

In all communities served for all types of general electric service which meets one of the following qualifications:

1. New Customers - An applicant with total expected demand of 200 Kw per month and usage of 750,000 Kwh per year is eligible for service under this rate if it can meet any one of the following requirements: (i) its activities are largely or entirely different than that of the previous customer; (ii) that non-seasonal business has not been conducted at the premise for at least three billing periods prior to the application; (iii) that seasonal business has not been conducted at the premise for at least thirteen billing periods prior to the application; or (iv) the facility is newly constructed.

2. Existing Customers and Existing In-state Customers of Competing Suppliers - An existing customer, or an existing in-state customer of a competing supplier with increased demand of 200 Kw per month and increased usage of 750,000 Kwh per year is eligible for service under this rate. Only the expanded portion of the facility will be eligible for the negotiated rate. In addition, the new load must be supplied from a separately metered circuit with separate metering equipment to be installed at the customer's expense. Average usage at the original facility must be at least as great as that which occurred in the previous 12 month period.

Rate:

Basic Service Charge:	$100.00 per month
Demand Charge:	To Be Negotiated
Energy Charge:	Otherwise applicable energy charge for General Service Rate 30.

Contracts shall be filed with and approved by the North Dakota Public Service Commission.

Minimum Bill:
Basic Service Charge plus Demand Charge.

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

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:
1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Right to Discontinue Service:
The Company reserves the right to refuse applicants who have not previously signed a contract for service under this rate if it determines either system capacity or system energy supply is projected to be insufficient, or if service reliability is expected to be at jeopardy.

Determination of Billing Demand:
The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 200 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

General Terms and Conditions:

1. The customer and the Company shall execute a contract for service to be effective under this rate for a period of five years from the date of service commencement.

2. The negotiated demand charge shall be increased according to the differential between the negotiated rate and the ceiling as portrayed by the following schedule.

Years	Differential Percent Decrease
1-3	0%
4	25%
5	50%

   At the end of the fifth year, the negotiated agreement hereunder expires.

3. Upon expiration of the contract, the customer shall be served under the otherwise applicable rate schedule.

4. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

Availability:

In all communities served for power to customers having a demand of 500 Kw or more for its interruptible load available for interruption for up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a separately metered circuit at the same voltage and phase utilized to serve the balance of the customer's electrical load so arranged to allow remote operation by the Company.

Type of Service:

Service under this rate shall be taken by the customer at whatever primary voltage is available at the point of delivery but not less than 2,400 volts. In the event that it is necessary to build a substation on the Company's transmission line to serve the customer, the cost of building the substation shall be a matter of negotiation between the Company and the customer.

Rate:

Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$ 9.35 per Kw
June – September	$12.35 per Kw
Energy Charge:	1.203¢ per Kwh

Minimum Bill:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. The customer shall execute an electric service agreement with the Company which will include a minimum term of service and any additional customer costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate.

2. All equipment associated with the interruptible load must be of such voltage and electrical characteristics that it can be separately metered and served from the circuit provided for the interruptible portion of the customer's load. If the equipment to be served is such that this is impossible, the customer must either make special arrangements with the Company or furnish the necessary

equipment suitable for connection and metering to the circuit for the interruptible portion of the load.

3. The customer must provide a load-break switch or circuit breaker equipped with electrical trip and close circuits allowing for remote operation of the customer's switch or circuit breaker by the Company. Customer must wire the trip and close circuits into a connection point designated by the Company to allow installation of control equipment by the Company. Customer must provide a continuous 120 volt AC power source at the connection point for operation of the Company's control system.

4. The customer is responsible for the remote terminal unit (RTU) equipment, if applicable, installation and upgrades costs located between the customer’s generator, or load control system, and the Company’s energy management control system. The Company shall notify the customer when an RTU upgrade is required and the customer shall be given the opportunity to decide whether the RTU upgrade (RTU upgrade event) is installed. If the RTU upgrade is not installed, the customer’s Rate 38 service shall be terminated and the customer moved to the otherwise applicable rate.

5. The Company may request the customer to interrupt at any time for up to 100 hours during an annual period beginning June 1 of each year and ending on May 31 of the following year. Company shall reimburse customer for customer’s fuel when interrupted at a mutually acceptable level and price.

6. Customer will be required to interrupt service within 10 minutes of the Company’s signal to interrupt service.

7. The penalty for non-performance when the Company requests the customer to interrupt will be the greater of $10.00 per Kw applicable to the Kw demand specified in the electric service agreement with the Company or the appropriate allocation of any penalties imposed on the Company by the Midcontinent Independent System Operator (MISO) during the period of non-performance. After a second failure to perform, within a 12-month period, the customer shall be liable for the penalty and may be moved to the otherwise applicable rate.

8. The Company may request a summer and winter performance test each year, lasting up to one hour in length, to test the customer's interruption capability. Scheduled performance tests shall not count against the 100 hour limit in Section 4 above. Two failures to perform, within a 12-month period, may result in the customer being moved to the otherwise applicable rate.

9. Additional terms and conditions may be added or amended from time-to-time with written notice to the customer to comply with MISO's load modifying resource (LMR) eligibility for the Company's utilization. The customer shall have the option of accepting the additional program rules provided by the Company or be moved to the otherwise applicable rate.

10. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

11. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

SMALL MUNICIPAL ELECTRIC SERVICE
Rate 40 (CLOSED)

Availability:

For all lighting and power requirements with billing demands of 50 kilowatts or less for public buildings or locations supported by public tax levies, and for which the city is liable for payment, in all municipalities served where the Company is operating under a municipal franchise or permit, and the municipality has a standard contract for operation of a street lighting system and/or a municipal pumping system with the Company.

This rate is restricted to small municipal electric service customers who were served under this rate prior to January 27, 1987. Any new small municipal general electric service customer may take service under another applicable rate.

Rate:

<u>Non-Demand:</u>

Basic Service Charge:	$1.15 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	4.321¢ per Kwh
Over 750 Kwh per month	3.221¢ per Kwh
June – September:	4.321¢ per Kwh

<u>Demand:</u>

Basic Service Charge:	$1.30 per day
Demand Charge:	
October – May:	
10 Kw or less	No Charge
Over 10 Kw	$12.19 per Kw
June – September:	$15.19 per Kw
Energy Charge:	2.221¢ per Kwh

SMALL MUNICIPAL ELECTRIC SERVICE
Rate 40 (CLOSED)

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

SMALL MUNICIPAL ELECTRIC SERVICE
Rate 40 (CLOSED)

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under the non-demand rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Customers not qualifying for the non-demand rate shall be served under the demand rate.

4. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

PUBLIC LIGHTING SERVICE Rate 41

Availability:

For the lighting of streets, alleys and other road right of ways. Service will be provided all night, every night in the year with a minimum service requirement of 4,000 hours annually.

Rate:

Primary Service:

Energy Charge:	5.180¢ per Kwh

Secondary Service:

Energy Charge:	5.680¢ per Kwh

Kwh shall be computed according to the total rated capacity of lamps in use.

Facilities Charge per unit per month:

LED, Overhead Conductor, Distribution Pole	$5.40
LED, Overhead Conductor, Street Light Pole	$10.50
LED, Underground Conductor, Distribution Pole	$7.10
LED, Underground Conductor, Street Light Pole	$12.20
Wood Lift Pole	$7.00

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

PUBLIC LIGHTING SERVICE Rate 41

General Terms and Conditions:

1. The Company will maintain the Company-installed and owned facilities when notified by customer or noticed by Company personnel. In case of vandalism, malicious mischief, or willful negligence the Company will charge the customer for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. In customer-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

4. When service is not metered, the energy usage shall be computed on a daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to the customer.

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Availability:

For municipal pumping purposes provided the municipality uses electricity exclusively for all its pumping requirements and purchases all such electricity from the Company. The municipality must sign a contract for a minimum period of one year.

Rate:

Primary Service:

Basic Service Charge: $80.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$ 9.00 per Kw
June – September:	$12.00 per Kw

Energy Charge: 1.826¢ per Kwh

Secondary Service:

Basic Service Charge: $45.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$ 9.00 per Kw
June – September:	$12.00 per Kw

Energy Charge: 1.926¢ per Kwh

Discount: For contracts of ten years or more 10%

Minimum Bill:

Basic Service Charge plus Demand Charge.

Payment:

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

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

2. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

OUTDOOR LIGHTING SERVICE Rate 52

Availability:

For all outdoor lighting including flood lights, billboard lighting, yard lights, and Christmas lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

Rate:

Primary Service:

Energy Charge:	6.766¢ per Kwh

Secondary Service:

Energy Charge:	7.172¢ per Kwh

Kwh shall be computed according to the total rated capacity of the units in use.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Applicable to Company-owned Facilities:
   a. The Company will install, own and operate the flood light(s), and yard light(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

   b. The light may be mounted on existing poles owned or controlled by the Company. The light may be installed on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

c. To the rate stated herein, fixture replacement and ownership costs for the units shall be added. The customer should consult with the Company for such costs.

d. The Company will maintain the Company-installed and owned facilities when notified by customer or noticed by Company personnel. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. For customer-owned outdoor lights, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

4. When service is not metered, the bill shall be computed on a daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to customer.

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

RENEWABLE RESOURCE COST ADJUSTMENT Rate 55

1. **Applicability:**
   This rate schedule represents a Renewable Resource Cost Adjustment (RRCA) and specifies the procedure to be utilized to recover the jurisdictional costs associated with renewable generation resource modifications or additions approved by the Commission, but not recovered through retail rates. Costs to be recovered may include operation and maintenance expenditures, depreciation, taxes, and a current return on the project costs.

2. **Renewable Resource Cost Adjustment:**
   a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the RRCA rates. The return component of the revenue requirement calculation will include the return on equity established in the Company's most recent rate case.
   b. The RRCA is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express RRCA applicability, and are allocated amongst the rate classes based on the Company's Demand/Energy Factor No. 3 established in the Company's most recent general rate case.
   c. The RRCA will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.
   d. A true-up will reflect any over or under collection of revenue under the RRCA based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Renewable Resource Cost Adjustment:**

Residential & Small General	0.899¢ per Kwh
Large General	0.838¢ per Kwh
Lighting	1.161¢ per Kwh

GENERATION RESOURCE RECOVERY RIDER Rate 56

Applicability:
This rate schedule represents a Generation Resource Recovery Rider (GRRR) and specifies the procedure to be utilized to recover the jurisdictional costs associated with generation resource additions approved by the Commission but not recovered through retail rates and financial incentives for power purchase agreement eligible for recovery under NDCC 49-06-02 subpart 4. Costs to be recovered may include operations and maintenance expenditures, depreciation, taxes, power purchase agreement financial incentives, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

1. Generation Resource Recovery Rider:

a. The North Dakota jurisdictional GRRR revenue requirement will be allocated to the customer classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case. The adjustment applied to the Residential, Small General Service and Lighting Classes will be calculated based on the customer class revenue requirement and the forecasted Kwh for the forecasted period. The adjustment applied to the Large General Service Class will be calculated based on the customer class revenue requirement and the forecasted demand for the forecasted period and expressed as a KW charge. The return component of the revenue requirement calculation will include the authorized return on equity specified in Case No. PU-22-___.

b. The GRRR is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express GRRR applicability, and are allocated amongst the rate classes based on the applicable demand factor.

c. The GRRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.

d. A true-up will reflect any over or under collection of revenue under the GRRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

2. Generation Resource Recovery Rider:

Residential & Small General	0.422¢ per Kwh
Large General	125.361¢ per KW
General Space Heating Rate 32	59.323¢ per KW
Lighting	0.131¢ per Kwh

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

State of North Dakota
Electric Rate Schedule

ENVIRONMENTAL COST RECOVERY RIDER Rate 57

1. **Applicability:**
   This rate schedule represents an Environmental Cost Recovery Rider (ECRR) and specifies the procedure to be utilized to recover the jurisdictional costs to be incurred by the Company in complying with federal and state environmental mandates determined to be eligible for recovery under NDCC 49-05-04.2. Costs to be recovered may include capital expenditures, depreciation, taxes, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

2. **Environmental Cost Recovery Rider:**
   a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the ECRR. The return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case.
   b. The ECRR is applicable to all retail customers for electric energy sold, except those served under special contracts, and are allocated amongst the rate classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case.
   c. The ECRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be eligible under NDCC 49-05-04.2.
   d. A true-up will reflect any over or under collection of revenue under the ECRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Environmental Cost Recovery Rider:**

Residential and Small General	0.000¢ per Kwh
Large General	0.000¢ per Kwh
Lighting	0.000¢ per Kwh

FUEL AND PURCHASED POWER ADJUSTMENT Rate 58

1. **Applicability:**
   This rate schedule sets forth the procedure to be used in calculating the Fuel and Purchased Power Adjustment (FPPA). It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power as allocated to North Dakota; and (b) amortization of the Deferred Fuel Cost Account.

2. **Effective Date and Limitation on Adjustments:**
   a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Purchased Power Adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Deferred Fuel Cost Account shall be April 1 of each year.

   b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of electric supply only when the amount of change in such adjustment is at least .001 cents per Kwh. The adjustment to be effective April 1 shall be filed each year, regardless of the amount of the change.

3. **Fuel and Purchased Power Adjustment:**
   a. The monthly Fuel and Purchased Power Adjustment shall be calculated separately for primary service and secondary service customers and shall reflect Montana-Dakota's cost of fuel and purchased power plus the annual Surcharge Adjustment.

   b. The cost of fuel and purchased power shall be calculated separately for primary service customers and secondary service customers, and shall be the sum of the following costs for the most recent four month period, as allocated to North Dakota and to the primary and secondary customer classes:

      1. The cost of fossil and other fuels and reagents, including sand, recorded in Account Nos. 501, 502 and 547.

2. Natural gas and pipeline reservation charges recorded in Account No. 547

3. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in the wholesale electric energy markets as recorded in Account No. 555

4. Capacity purchases as recorded in Account No. 555.

5. Regional Market Administration expenses recorded in Account No. 575.

6. Less 100 percent of the wholesale sales revenue.

7. Less the revenue from the sales of Renewable Energy Credits (RECs).

c. The cost per Kwh for the month is the sum of 3(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes.

4. **Surcharge Adjustment:**
All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on April 1 each year. The Surcharge Adjustment per Kwh sold shall reflect the amortization of the applicable balance in the Deferred Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

a. The balance in the Deferred Fuel Cost Account (Account 182.3) includes:

1. The current month over or under recovery, determined as follows:

i. Montana-Dakota shall determine each month the cost for that month's fuel and purchased power.

ii. Montana-Dakota shall subtract from the month's cost determined in 4.a.1.i the revenue collected under the Fuel and Purchased Power Adjustment for that month.

iii. The resulting difference (positive or negative) shall be included separately for primary and secondary service classes.

2. Refunds from supplier(s) and market operators with respect to fuel and purchased power costs.

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

5. Manner of Filing:
The Company shall file a monthly statement showing the calculation of the Fuel and Purchased Power Adjustment with the Commission prior to implementing the monthly adjustment. The adjustment in rates shall be effective with service rendered on and after the first day of each month, unless the Commission shall otherwise order.

6. Fuel and Purchased Power Adjustment:
The current and historical Fuel and Purchased Power Adjustment for primary and secondary service customers can be found at www.montana-dakota.com/rates-and-services.

TRANSMISSION COST ADJUSTMENT Rate 59

1. **Applicability:**
This rate schedule represents a Transmission Cost Adjustment (TCA) and specifies the procedure to be utilized to recover the net balance of the capital and operating costs and revenue credits of Montana-Dakota's transmission related expenses and revenues determined to be eligible for recovery in accordance with 49-05-04.3 NDCC. Costs to be recovered under the Transmission Adjustment shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

2. **Transmission Cost Adjustment:**
   a. An adjustment per Kwh will be determined based on the cumulative transmission related costs and revenue credits eligible for recovery and as allocated to the North Dakota jurisdiction and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

   b. The adjustment will be applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express TCA applicability, and allocated among the rate classes based on the transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case.

   c. The adjustment per Kwh will be revised annually to reflect the current level of costs to be recovered.

   d. The true-up will reflect any over or under collection of revenue under the Transmission Adjustment from the preceding twelve month period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

TRANSMISSION COST ADJUSTMENT Rate 59

3. Transmission Cost Adjustment Rate by class:

Residential & Small General	0.801¢ per Kwh
Large General	0.636¢ per Kwh
Lighting	0.360¢ per Kwh

OCCASIONAL POWER PURCHASE Rate 95
NON-TIME DIFFERENTIATED

Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating occasional electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 100 Kw or less, that are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$0.05 per day
With instrument transformers:	$0.19 per day
Metering charge for three phase service:	$0.12 per day
With instrument transformers:	$0.33 per day

Energy delivered to and accepted by Company by a QF shall be paid for by Company in accordance with one of the following two options, elected by the QF:

1. Simultaneous Purchase and Sale:
   Energy sales to QF - Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

   Energy purchases by Company:

   Energy Payment = 2.145¢ per Kwh

2. Net Billing:
   Energy generated will be compensated on a net billing basis. The Company will install a meter to measure the energy generated by the QF. The Company will also install a meter to measure the energy consumed by the QF. Metered generation will be subtracted from the metered consumption for the billing period.

If metered generation is less than metered consumption, the QF will be billed the applicable retail rate. If metered generation is greater than the metered consumption, the QF will be paid for each Kwh at an amount equal to:

2.145¢ per Kwh

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.

2. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

3. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

4. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be at least one year but less than five years.

5. In order to qualify for the net billing option, the generating equipment and the load of the facility must be located at the same "physical site". "Physical site" shall mean on the same tract of land and the generator output must be physically connected to the load service entrance.

6. For general terms and conditions covering QF's, see Rate 140.

7. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

PARALLEL GENERATION PEAKING FACILITY
PURCHASE Rate 96 TIME DIFFERENTIATED

Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 1000 Kw or less, that operate as a peaking facility (defined below), and are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$ 0.16 per day
With instrument transformers:	$ 0.30 per day
Metering charge for three phase service:	$ 0.18 per day
With instrument transformers:	$ 0.38 per day

1. Capacity delivered to the Company:

   Monthly capacity payments for a QF (not registered as a MISO generator) shall be assigned by Montana-Dakota based upon the amount of qualifying capacity assigned to an eligible resource under BPM-011 Resource Adequacy of the MISO tariff subject to adjustment annually in accordance with BPM-011.

   Monthly capacity payments for a MISO-registered QF shall be based on the capacity credits assigned by MISO on an annual basis.

   Monthly capacity payment shall be the MISO capacity auction clearing price for Zone 1. The capacity payment is subject to change annually through the year 2030. Effective in 2031 the monthly capacity payment shall be $9.655 per Kw applicable for the remainder of the term of the contact.

   Capacity payments will be paid in the subsequent billing period.

2. Energy Payment:

	ON-PEAK	OFF-PEAK
	2.072¢ per Kwh	2.139¢ per Kwh

Peak Periods: The On-Peak Period is defined as those hours between 12 p.m. and 8 p.m. local time, Monday through Friday in the months of June through September. The Off-Peak Period is defined as all other hours. Definitions of On-Peak and Off-Peak periods are subject to change with change in the Company's system operating characteristics.

Energy Sales to Qualifying Facilities:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.

2. Service under this schedule shall be on a simultaneous purchase and sale basis only.

3. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

4. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

5. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be five years or more.

6. Line loss considerations will be determined on a site specific basis.

7. For dispatchable units, generator outages must be pre-scheduled with Company to provide coordination with Company units.

8. A Peaking Unit is a unit not designed for continuous operation and is capable of supplying capacity and energy during periods of peak electric consumption. Generally, peaking units have a capacity factor of 20% or less.

9. For general terms and conditions covering QF's, see Rate 140.

10. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

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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 (Commission) 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. Also refer to Electric Service Rules & Regulations Rate 110.

II. DEFINITIONS:

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

APPLICANT – A customer requesting Company to provide service.

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

COMPANY – Montana-Dakota Utilities Co.

CUSTOMER – Any individual, partnership, corporation, firm or 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.

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.

III. GENERAL TERMS AND CONDITIONS:

1. RULES FOR APPLICATION OF ELECTRIC SERVICE:
   i. Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

      a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate. Where premise is defined as a contiguous parcel of land undivided by a dedicated street, alley, highway, or other public thoroughfare or railway.

      b. Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

      c. Only single phase service is available under the Residential Electric Service Rate.

   ii. Three phase service shall be served under the appropriate General Electric Service Rate.

   iii. General Electric Service is defined as service provided to non-residential services, such as 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 parlors, apartment houses with master metering exemptions, 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).

iv. If separate metering is not practical for a single unit (one premise) that is using electricity for both domestic purposes and for conducting business (or for nonresidential purposes), 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 General Electric Service) applicable to the type of service which constitutes 50% or more of the total connected load.

v. 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 appropriate General Electric Service Rate.

2. CONSUMER DEPOSITS:
The Company will determine whether or not a deposit shall be required of an applicant for electric service in accordance with Commission rules.

i. The amount of such deposit shall not exceed an estimated 60 day service bill.

ii. 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 or 30

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.

iii. 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.

iv. Deposits shall be refunded to customers at termination provided all billings for service have been paid. Deposits will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record has been established.

3. LATE PAYMENT CHARGE:
Bills will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any past due balance.

4. 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.

5. 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.

6. TAX CLAUSE:
In addition to the charges provided for in the electric 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.

7. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS:
   For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

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

8. RECONNECTION FEE FOR SEASONAL CUSTOMERS:
   A charge will be collected for reconnecting electric service to a customer who requests reconnection of service, at a location where the same customer discontinued the same service during the preceding twelve-month period.

   Applicable Charge:

   i. Customers with non-demand meters: $20.00
   ii. Customers with demand meters: $40.00

9. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILL:
   i. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(1), the Company may disconnect service if the customer is delinquent in payment for service, and fails to pay for service or enter into a

satisfactory installment agreement with the Company for payment within ten (10) days of the Company giving the customer written notice of the Company's intention to discontinue service on account of payment delinquency.

ii. All bills for service are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of service bills, such service may be discontinued by the Company under the applicable rules of the Commission.

iii. If a customer's credit standing becomes unsatisfactory after a deposit has been refunded or if the deposit is inadequate to cover the estimated charge for furnishing service for a 60-day period, a new or additional deposit may be required upon reasonable written notice by the Company.

iv. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(10), the Company may not discontinue service to the Customer for nonpayment of a deposit.

v. The Company may collect a fee of $20.00 before restoring electric service which has been discontinued for nonpayment of service bills, or where a Service Extender has been installed in lieu of full disconnection.

10. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS:
The Company reserves the right to discontinue service for any of the following reasons:

i. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

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

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

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

v. 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 $20.00 before restoring electric service, which has been disconnected for the above causes.

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

12. METHOD OF COMPUTING INITIAL OR FINAL BILLS FOR ELECTRIC SERVICE FOR LESS THAN A FULL MONTHLY BILLING PERIOD:
Customer’s meters are read as nearly as practicable at thirty day intervals. When service is begun or terminated at any location between regular meter reading dates, bills will be prorated on a daily basis, whenever the billing period is less than 27 calendar days or more than 35 calendar days. The minimum monthly bill, basic service charge, kilowatt hour blocks and demand charge provisions in all rate schedules will be prorated.

13. SELECTIVE TESTING PLAN FOR METERS:
    The electric meter population shall be tested in accordance with the Electric Meter Testing Program approved by the Commission.

14. BILLING ADJUSTMENTS:
    If a meter or billing error results from 1) an inaccurate meter; 2) an Incorrect reading of the meter; 3) an incorrect application of a rate schedule; 4) an incorrect connection of the meter; 5) an application of an incorrect multiplier or constant; or 6) other similar errors affecting customer bills.

    i. If a Customer is underbilled, the Company may recalculate the bills and reissue corrected bills for service during the period of the error, up to a maximum period of six years from the date of the bill, with the exception of a meter equipment failure.

    ii. If a Customer is overbilled, the Company shall recalculate bills for errors resulting in overcharges up to a maximum of six years from the date of payment, with the exception of a meter equipment failure. In the case of a meter equipment failure, the Company may charge the Customer for a period equal to one-half the time elapsed since the last previous meter test, but not to exceed six months.

15. MODIFICATION OF RATES, RULES AND REGULATIONS:
    Company reserves the right to modify its rates, rules, and regulations or other provisions now or hereafter in effect, in any manner permitted by law.

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC SERVICE
RULES and REGULATIONS

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101. Definitions
Company – Montana-Dakota Utilities Co.

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

102. Purpose
These rules are intended to define good practice which can normally be expected, but are not intended to exclude other generally 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 Regulatory Commissions 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.

103. Customer Obligation
103.1 Application for Service – A customer desiring electric service must submit an 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 service 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 electric service 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 electric service until notified by the 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 necessary.

103.2 Access to Customer's Premises – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

103.3 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.

103.4 Relocated Facilities – Where Company facilities are located on or adjacent to a customer's premises where there is an encroachment(s) to electric facilities the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

103.5 Notification of Unsafe Conditions – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

103.6 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.

<u>104. Liability</u>
104.1 Continuity of Service – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

104.2 Customer's Equipment – Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed 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, leased by the customer from third parties or used on the customers premise. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

104.3 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 electricity 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.

104.4 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.

104.5 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.

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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or 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.

105. Electrical Codes and Ordinances
The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

106. Wiring Adequacy
Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

107. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

108. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 107 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

109. Consultation with the Company
109.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

109.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

109.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

110. Unauthorized Use of Service
110.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

110.2 Types of unauthorized use of service include, but are not limited to, the following:
- (a) Bypass around meter.
- (b) Meter reversed.
- (c) Equipment connected ahead of meter.

(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

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

(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

110.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any charges which are due, including:

(a) All delinquent bills, if any;
(b) The amount of any Company revenue loss attributable to said tampering;
(c) Expenses incurred by the Company in replacing or repairing the meter or other equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 110.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with rules of the applicable State Public Service or Utilities Commission.

<u>111. Unauthorized Attachments to Poles</u>

111.1 The unauthorized attachment of any flags, banners, signs, clotheslines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

111.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules
Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy
The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service
Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service
Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer’s expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service
Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on the Customer's Premises

206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company's power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer's expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

207. Overhead to Underground Primary Conversion

When requested by property owners, underground distribution and services will be provided to replace existing overhead distribution to a group of owners cooperating with one another, providing:

(a) There exists a sufficient number (25) of homes on contiguous lots that are available for the conversion. At the Company's option, smaller groups could be acceptable.

(b) The terrain and other soil conditions are suitable for installation of underground facilities.

(c) Easements will be granted at no cost to the Company, wherever installed facilities are on private land.

(d) The customer, at customer's expense, must adapt the customer's electrical facilities to accept an underground service.

(e) The customer, or group of customers, provide payment for the cost of removal of overhead facilities and total installed cost, multiplied by the fractional life remaining, less the salvage value of the removed equipment. The customers may also be required to reimburse the company for other reasonable and prudent costs in excess of the Company's standard installation that result from the installation of the requested underground distribution.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency

All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400)

302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service
1	3	120/240	Single Phase Lighting & Power
3	4 Delta	120/240	Combined Light & Power *
3	4 Wye	208 Grd Y/120	Combined Light & Power
3	4 Wye	480 Grd Y/277	Combined Light & Power **
3	4 Delta	240/480	Combined Light & Power *

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 109)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to Paragraphs 103.1, 107, and 108.)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electric Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly

marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops

407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (refer to the National Electrical Safety Code for possible exceptions):

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate at a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:
- (1) 17 feet - where multiplex service drops cross over or run along alleys, driveways, or parking lots.
- (2) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 14 feet - over residential driveways for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:
- (1) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 12 feet - for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electric Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18 inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete driveway, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in approved mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the Customer's particular needs.

502. Service Entrance Equipment
The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection
The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means
504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance
Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 – METERING

601. General
The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes.
It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets – Single-Phase, Three-Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the Company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations.
4. 150 ampere minimum for underground service installations.
5. Stud connectors are required for all sockets rated 320 amps or greater.
6. For sockets rated below 320 amps, study connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
7. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
8. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
9. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weatherproof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.

4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rated meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3.)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into or ahead of the meter socket.

603. Meter-Switch-Fuse Wiring Sequence

For all secondary voltage metering installations the meter, entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. Additionally, for 480 volt installations, a customer-owned, non-fused, main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by the Company. The switch shall be labeled “Utility Disconnect”. By exception and upon consultation with the Company, an overcurrent circuit breaker may be installed ahead of a gang style metering installation with 6 or more sockets as an Emergency Disconnect. Access to the Emergency Disconnect Switch shall be lockable and shall be locked by the Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company. (Refer to Figure 1.)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet - 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by customer. (Refer to Figures 1, 2, and 3.)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering

Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams

Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling

Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates

shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals
All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building which contain unmetered wires, shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads
Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at customer's expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics
702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection.

703. Power Factor
Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in

certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment
At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders
Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors
706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to paragraph 702)

706.4 The size of three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

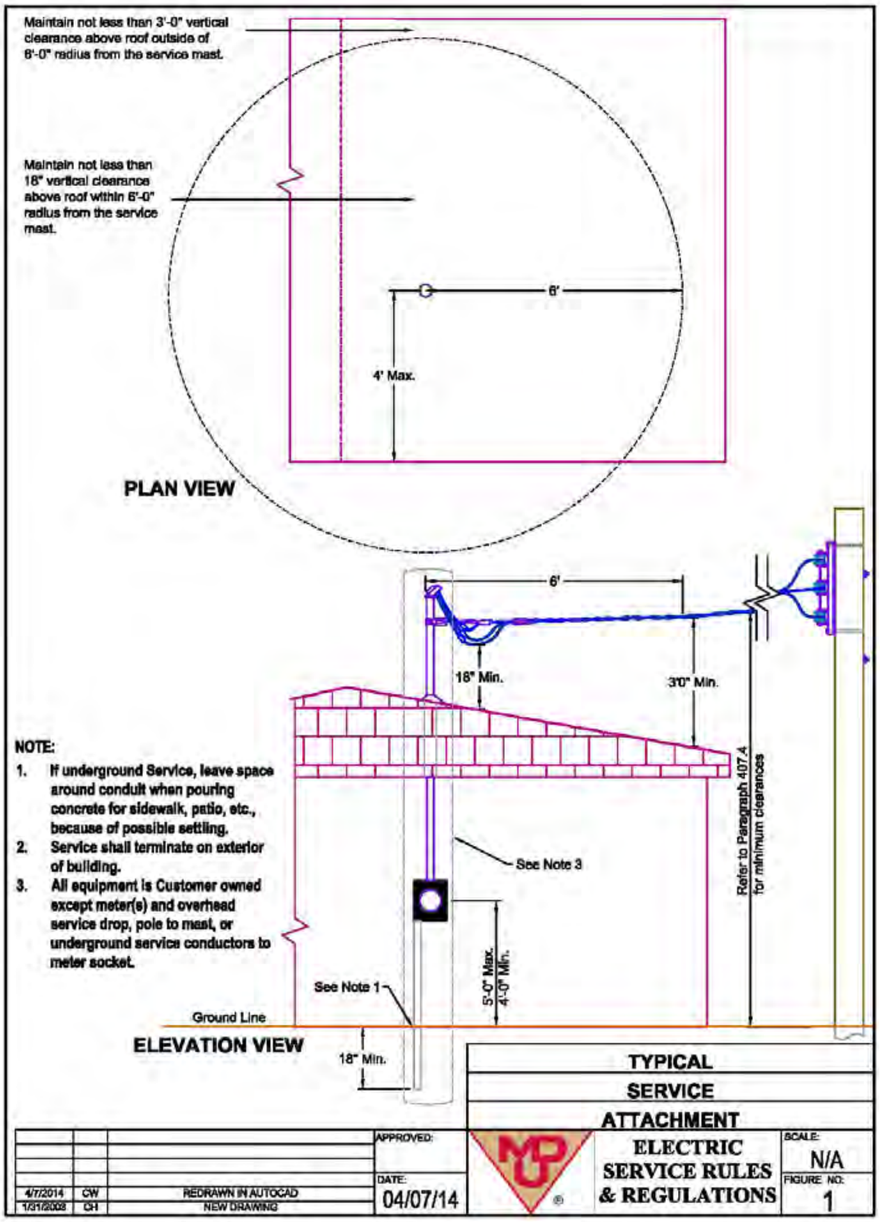
707. Flashing Display Signs
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

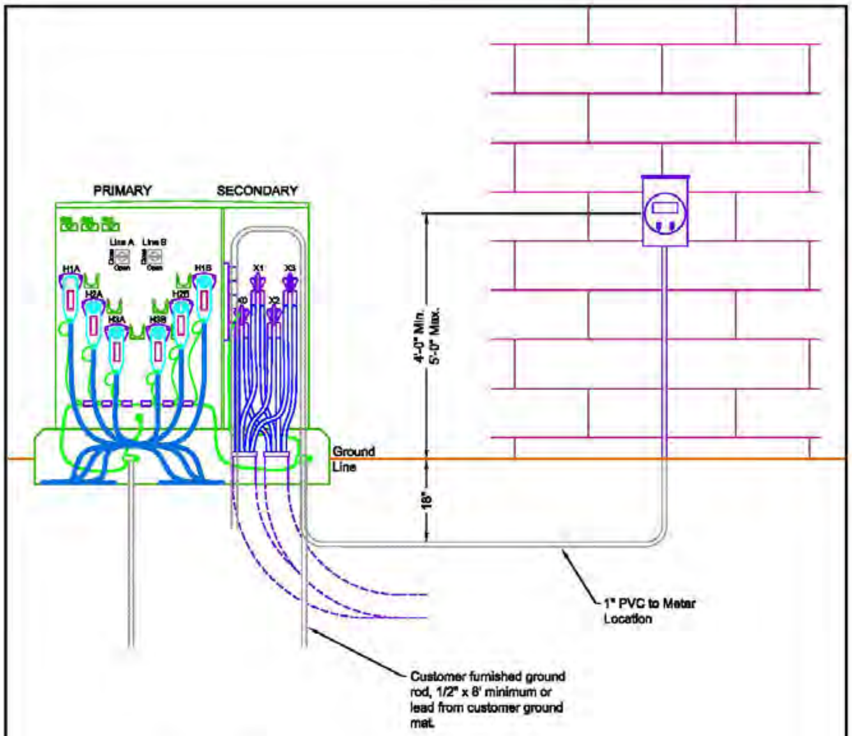
708. Fluorescent and Gaseous Tube Lighting
High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

709. Electric Heat Equipment
A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

710. Computers and Electronic Equipment
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to Paragraph 104.2.)

711. Carrier Equipment
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system.


Maintain not less than 3'-0" vertical clearance above roof outside of 6'-0" radius from the service mast.
Maintain not less than 18" vertical clearance above roof within 6'-0" radius from the service mast.
6'
4' Max.
PLAN VIEW
6'
18" Min.
3'0" Min.
NOTE:
1. If underground Service, leave space around conduit when pouring concrete for sidewalk, patio, etc., because of possible settling.
2. Service shall terminate on exterior of building.
3. All equipment is Customer owned except meter(s) and overhead service drop, pole to mast, or underground service conductors to meter socket.
See Note 3
Refer to Paragraph 407.4 for minimum clearances
5'-0" Max.
4'-0" Min.
See Note 1
Ground Line
ELEVATION VIEW
18" Min.
TYPICAL
SERVICE
ATTACHMENT
APPROVED:
DATE:
04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
SCALE:
N/A
FIGURE NO:
1
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2002 CH NEW DRAWING



NOTES:

1. Meter socket shall not be mounted directly on the padmount transformer.
2. 1" PVC shall be used from meter socket to padmount transformer.
3. Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.

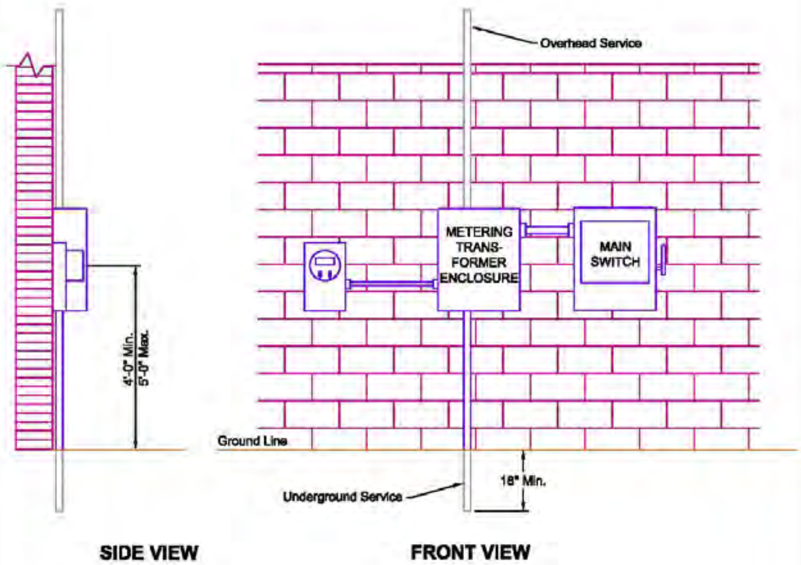
TRANSFORMER RATED
METERING
PADMOUNT TRANSFORMER

4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED: Pending
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A

FIGURE NO: 2



NOTE:

1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3. Equipment is to be installed outdoors.

4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED:
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

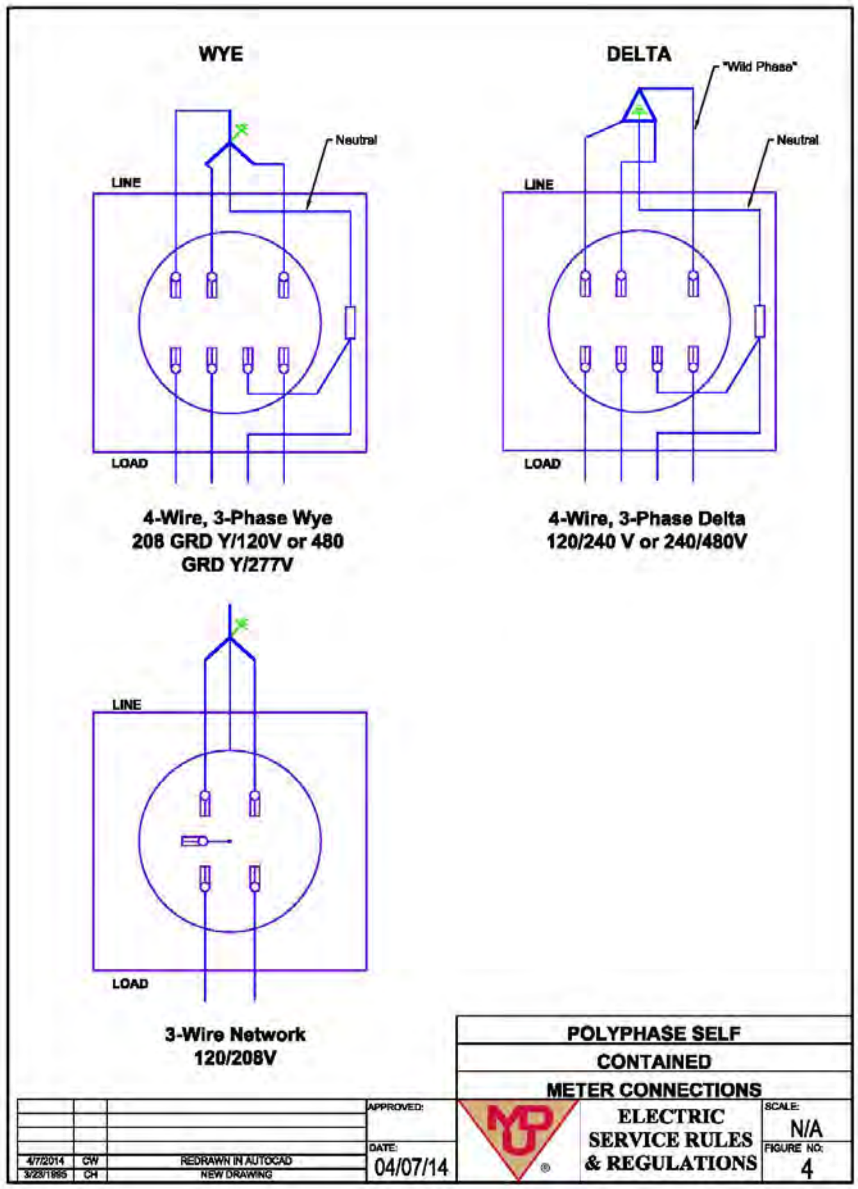
TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE

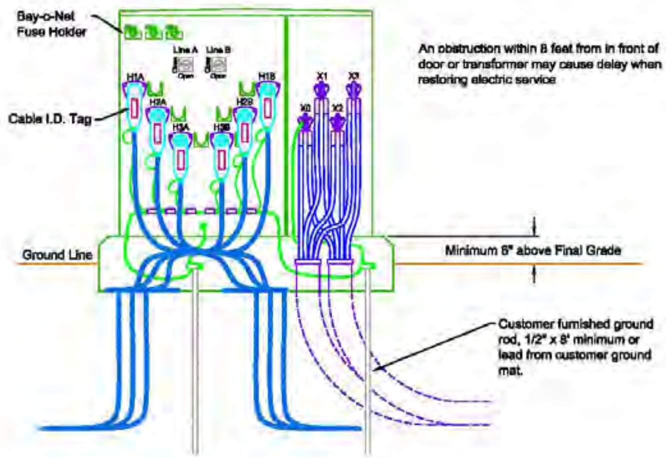
ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A

FIGURE NO: 3

ELECTRIC SERVICE RULES AND REGULATIONS Rate 110





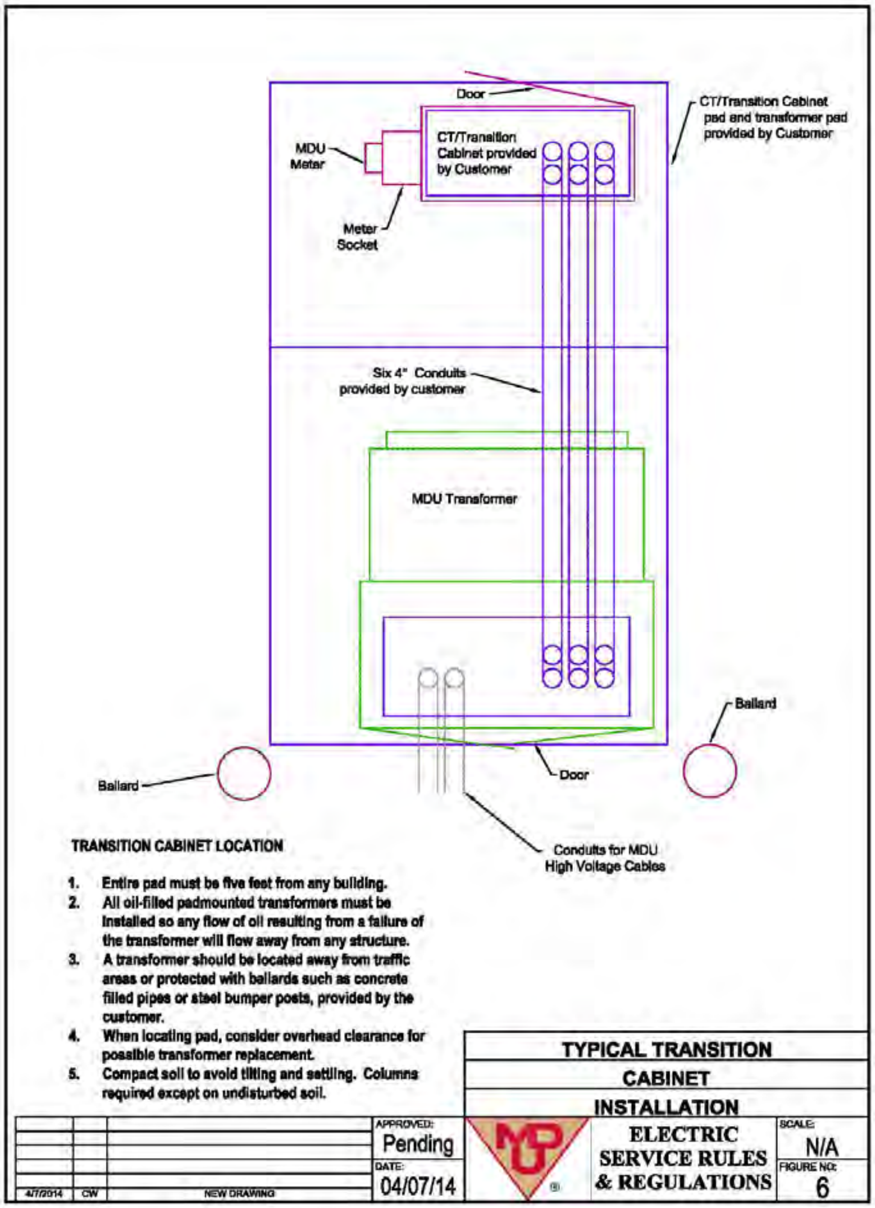
NOTES:

1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

TRANSFORMER LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

			APPROVED: Pending	TYPICAL PADMOUNT EQUIPMENT INSTALLATION	SCALE: N/A
4/7/2014	CW	REDRAWN IN AUTOCAD	DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS	FIGURE NO: 5
1/31/2003	CH	NEW DRAWING			


Door
CT/Transition Cabinet pad and transformer pad provided by Customer
MDU Meter
CT/Transition Cabinet provided by Customer
Meter Socket
Six 4" Conduits provided by customer
MDU Transformer
Ballard
Ballard
Door
Conduits for MDU High Voltage Cables
TRANSITION CABINET LOCATION
1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.
TYPICAL TRANSITION
CABINET
INSTALLATION
ELECTRIC SERVICE RULES & REGULATIONS
APPROVED: Pending
DATE: 04/07/14
SCALE: N/A
FIGURE NO: 6
4/7/2014 CW NEW DRAWING

ELECTRIC EXTENSION POLICY Rate 112

The policy of Montana-Dakota Utilities Co. for electric extensions to provide service to customers located within its service territory is as follows:

1. A permanent extension may be constructed without a contribution if the estimated project construction cost is equal to or less than 3.8 times the estimated annual revenue excluding fuel and purchased power (3.8 to 1 ratio).

2. If the estimated project construction cost is greater than 3.8 times the estimated annual revenue excluding fuel and purchased power, the extension will be made only with a contribution, which may be refundable.

   a. Contribution -

      1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the initial contribution shall be the estimated construction cost less 3.8 times the estimated annual revenues excluding fuel and purchased power.

      2) The initial contribution for developers of subdivisions shall be the estimated construction cost.

      3) Payment of the initial contribution amount shall be made prior to construction.

      4) Upon completion of construction, the contribution amount shall be adjusted to reflect actual construction costs and an additional charge or refund levied accordingly.

      5) Company may waive all contributions if it determines that the initial contribution will be soon refunded because of additional customer connections.

b. Refund -
   1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above referred to extension, Company shall recompute the contribution required by combining the estimated proposed construction cost for the new customer(s) with the construction cost to those customers already taking service. If, by so combining the construction costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

   2) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue excluding fuel and purchased power of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

   3) No refund shall be made by Company to customer(s) or developer after a five-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

   4) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction.

3. Project construction cost shall include all cost of the electric extension and overhead cost less the cost of customers' transformer(s), service line, and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

ELECTRIC EXTENSION POLICY Rate 112

4. Electric extension refers to any facilities which must be constructed to connect a new customer to the utility system or the addition of capacity to existing facilities.

5. Company will deliver electricity to customer at the rate approved by the North Dakota Public Service Commission.

6. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

7. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

8. This rule shall not be construed as prohibiting the Company from making a contract with a customer in a different manner, if the contract provides a more favorable method of extension to the customer. Such determination to be made on the basis of specific extension characteristics.

9. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

A. NEW METERS

A sampling of 5% will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

B. RESIDENTIAL WATTHOUR METERS IN SERVICE

1. A random selection of meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979, 1980 to 1989, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

C. COMMERCIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

D. INDUSTRIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than ±2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

4. Whenever it is found that less than 99% of the tested meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the $\pm$2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

General Rules for Generation:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This does not affect the responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is de-energized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used, whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights are to be furnished by the owner of the qualifying facility on owner's property.

13. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

14. If the qualifying facility is located at a site outside of Company service territory and energy is delivered to Company through facilities owned by another utility, energy payments will be adjusted reflecting losses occurring between point of metering and point of delivery.

15. In the event the qualifying facility desires wheeling by the Company of its output, arrangements will be made subject to negotiation.

16. A Metering Charge will be assessed the qualifying facility for installation by the Company of additional metering equipment plus operation and maintenance costs.

17. An Interconnection Charge will be assessed for any additional facilities (exclusive of the items included in Metering Charge) or changes in existing facilities to permit interconnection with the Company. Payment shall be a one-time payment.

18. The owner of a qualifying facility will indemnify and save the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

19. Qualifying facilities shall be required to execute a contract that specifies a one or five-year minimum term depending upon applicable rate schedule and describes the responsibilities, liabilities, ownership of equipment, and location.

20. The owner of a qualifying facility shall obtain and maintain general liability insurance in an amount established by negotiation between the owner of a qualifying facility and the Company.

21. Qualifying facilities with generating capacity greater than 1000 Kw, or operating as a base loaded unit regardless of size, will require individual negotiation.

Tariffs Reflecting Proposed Changes

State of North Dakota
Electric Rate Schedule

TABLE OF CONTENTS

TABLE OF CONTENTS

State of North Dakota
Electric Rate Schedule

COMMUNITIES SERVED

ELECTRIC SERVICE

Dakota Heartland Region

Almont
Apple Valley
Ashley
Beulah
Bismarck*
Braddock
Burnstad
Carson
Center
Dawson
Driscoll
Elgin
Ellendale
Forbes
Fredonia
Fullerton
Glen Ullin
Golden Valley
Hague
Hazelton
Hazen
Hebron
Heil
Judson
Kintrye
Kulm
Lehr
Leith
Linton
Mandan
McKenzie
Merricourt
Monango
Napoleon
New Leipzig
New Salem
Selfridge
Steele
Sterling
Strasburg
Tappen
Venturia
Wishek
Zap
Zeeland

*Designates Region Office

ELECTRIC SERVICE

Badlands Region

Alamo
Alexander
Ambrose
Appam
Arnegard
Battleview
Beach
Belfield
Bentley
Bowbells
Bowman
Bucyrus
Burt
Carpio
Columbus
Corinth
Corteau
Coulee
Crosby
Dickinson*
Dodge
Donnybrook
Dunn Center
East Fairview
Epping
Flaxton
Gladstone
Gascoyne
Grenora
Halliday
Hamlet
Hanks
Haynes
~~Hebron~~
Hettinger
Kenmare
Killdeer
Larson
Lemmon
Lignite
Loraine
Marmarth
McGregor
Mohall
Morristown
Mott
New England
Noonan
Norma
Northgate
Portal
Powers Lake
Rawson
Ray
Reeder
Regent
Rhame
Richardton
Ross
Scranton
Sentinel Butte
Sherwood
South Heart
Springbrook
Stanley
Taylor
Tioga
Tolley
Watford City
Werner
Wheelock
Wildrose
Williston
Zahl

*Designates Region Office

RESIDENTIAL ELECTRIC SERVICE Rate 10

Availability:

In all communities served for single-phase residential electric service for domestic purposes only.

Rate:

Basic Service Charge:		$~~0.46~~0.67 per day
Energy Charge:		
October – May:		
	First 750 Kwh per month	~~5.678~~6.512¢ per Kwh
	Over 750 Kwh per month	~~2.678~~3.512¢ per Kwh
June – September:		~~5.678~~6.512¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 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~~

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Availability:

In all communities served for single-phase residential electric for customers operating Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning purposes where electric space heating is the primary heating source. Service under this rate is not available when another energy source provided by the Company is utilized as a back-up heating source.

Rate:

Basic Service Charge: $~~0.75~~1.05 per day

Off-Peak Energy Charge:

For all energy used during the designated hours of 10:00 p.m. to 8:00 a.m. local time.

October – May:	1.100¢ per Kwh

On-Peak Energy Charge:

For all energy not covered by the Off-Peak rating period.

October – May:	
First 750 Kwh per month	~~5.846~~6.512¢ per Kwh
Over 750 Kwh per month	~~2.846~~3.512¢ per Kwh
June – September:	~~5.846~~6.512¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

OPTIONAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Thermal storage space heating facilities can include the thermal storage device(s), air-source heat pumps, and associated air handling units.

2. Unless approved by the Company the maximum thermal storage facilities that may be connected under this rate schedule is 50 Kw.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of North Dakota
Electric Rate Schedule

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

Availability:

In all communities served for single-phase residential electric service. The customer's wiring must be so arranged that all service can be measured through one meter.

Rate:

Basic Service Charge: $~~0.75~~1.05 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	~~5.718~~6.395¢ per Kwh
June – September	~~7.218~~7.895¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	~~2.718~~3.395¢ per Kwh
June – September	~~4.218~~4.895¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

Montana-Dakota Utilities Co.
~~A Division of MDU Resources Group, Inc.~~
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State of North Dakota
Electric Rate Schedule

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Residential Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Residential Electric Service rate or returning to the regular Residential Electric Service rate.

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 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 types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be so arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Basic Service Charge:	$~~0.84~~1.15 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	~~5.997~~6.756¢ per Kwh
Over 750 Kwh per month	~~2.997~~3.756¢ per Kwh
June – September:	~~5.997~~6.756¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Non-metered services. At the Company's discretion, the installation of a meter on a customer's service may not be warranted. In the absence of measuring a customer's use, customers will be billed a predetermined energy use amount each month based on the operating characteristics of the equipment being served, such as Wi-Fi equipment served on Company-owned poles.

4. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of North Dakota
Electric Rate Schedule

IRRIGATION POWER SERVICE Rate 25

Availability:
For irrigation power service.

Rate:

Basic Service Charge:	$~~1.50~~1.90 per day
Demand Charge:	
October – May	$~~1.25~~2.74 per Kw
June – September	$~~4.25~~5.74 per Kw
Energy Charge:	~~0.186~~0.406¢ per Kwh

Minimum Bill:
Basic Service Charge.

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

Power Factor Clause:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Determination of Billing Demand:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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

State of North Dakota
Electric Rate Schedule

OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

Availability:

In all communities served for all types of general electric service with billing demands that do not warrant the installation of a demand meter except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Basic Service Charge: $~~1.00~~1.30 per day

On-Peak Energy:

For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.

October – May	~~4.566~~5.043¢ per Kwh
June – September	~~6.066~~6.543¢ per Kwh

Off-Peak Energy:

For all energy not covered by the On-Peak rating period.

October – May	~~2.066~~2.543¢ per Kwh
June – September	~~3.566~~4.043¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day Small General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Small General Electric Service rate or returning to the regular Small General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under this rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SERVICE Rate 30

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter. If the customer does not connect his wiring into a single system, each meter shall constitute a separate billing unit.

Rate:

Primary Service:

Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$~~11.00~~12.85 per Kw
June – September	$~~14.00~~15.85 per Kw
Energy Charge:	~~1.414~~1.689¢ per Kwh

Secondary Service:

Basic Service Charge:	$56.00 per month
Demand Charge:	
October – May	$ ~~9.50~~10.08 per Kw
June – September	$~~12.50~~13.08 per Kw
Energy Charge:	~~2.331~~2.606¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 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~~

Availability:

In all communities served for all types of demand metered general electric service except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

Rate:

Primary Service:

Basic Service Charge:	$97.00 per month
On-Peak Demand:	
October - May	$~~12.25~~12.96 per Kw
June - September	$~~15.25~~15.96 per Kw
On-Peak Energy:	
For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday.	~~1.607~~1.846¢ per Kwh
Off-Peak Energy:	
For all energy not covered by the On-Peak rating period.	~~1.357~~1.596¢ per Kwh

Secondary Service:

Basic Service Charge:	$72.00 per month
On-Peak Demand:	
October – May	$~~10.75~~11.43 per Kw
June – September	$~~14.75~~15.43 per Kw

On-Peak Energy:
For all Kwh's used during peak hours designated as 12 p.m. to 8 p.m. local time, Monday through Friday. ~~2.512~~2.751¢ per Kwh

Off-Peak Energy:
For all energy not covered by the On-Peak rating period. ~~2.262~~2.501¢ per Kwh

Minimum Bill:
Basic Service Charge.

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

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Determination of On-Peak Billing Demand:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month defined as 12:00 p.m. to 8:00 p.m. local time, Monday through Friday. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

OPTIONAL TIME-OF-DAY GENERAL ELECTRIC SERVICE Rate 31

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Contract Terms:

Customer agrees to contract for service under the Optional Time-of-Day General Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day General Electric Service rate or returning to the regular General Electric Service rate.

General Terms and Conditions:

1. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 32

Availability:

In all communities served for space heating service, where the customer also takes service under another general service rate schedule offered by the Company. Space heating equipment, including combination space heating and cooling equipment such as heat pumps and packaged roof-top heating/cooling units where heating use is the principal load may be served under this rate schedule.

Rate:

Basic Service Charge:	$~~21.00~~23.00 per month
Primary Service:	
Demand Charge:	
October – May	$ ~~1.00~~1.71 per Kw
June – September	$~~14.00~~15.85 per Kw
Energy Charge:	~~1.422~~1.772¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$ ~~1.00~~1.71 per Kw
June – September	$~~12.50~~13.08 per Kw
Energy Charge:	~~2.422~~2.772¢ per Kwh

Minimum Bill:

Basic Service Charge.

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. The foregoing schedule is subject to Rates 100-112 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.
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400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

FIRM SERVICE ECONOMIC DEVELOPMENT Rate 34

Availability:

In all communities served for all types of general electric service which meets one of the following qualifications:

1. New Customers - An applicant with total expected demand of 200 Kw per month and usage of 750,000 Kwh per year is eligible for service under this rate if it can meet any one of the following requirements: (i) its activities are largely or entirely different than that of the previous customer; (ii) that non-seasonal business has not been conducted at the premise for at least three billing periods prior to the application; (iii) that seasonal business has not been conducted at the premise for at least thirteen billing periods prior to the application; or (iv) the facility is newly constructed.

2. Existing Customers and Existing In-state Customers of Competing Suppliers - An existing customer, or an existing in-state customer of a competing supplier with increased demand of 200 Kw per month and increased usage of 750,000 Kwh per year is eligible for service under this rate. Only the expanded portion of the facility will be eligible for the negotiated rate. In addition, the new load must be supplied from a separately metered circuit with separate metering equipment to be installed at the customer's expense. Average usage at the original facility must be at least as great as that which occurred in the previous 12 month period.

Rate:

Basic Service Charge:	$100.00 per month
Demand Charge:	To Be Negotiated
Energy Charge:	Otherwise applicable energy charge for General Service Rate 30.

Contracts shall be filed with and approved by the North Dakota Public Service Commission.

Minimum Bill:
Basic Service Charge plus Demand Charge.

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

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

Right to Discontinue Service:
The Company reserves the right to refuse applicants who have not previously signed a contract for service under this rate if it determines either system capacity or system energy supply is projected to be insufficient, or if service reliability is expected to be at jeopardy.

Determination of Billing Demand:
The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 200 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

FIRM SERVICE ECONOMIC DEVELOPMENT Rate 34

General Terms and Conditions:

1. The customer and the Company shall execute a contract for service to be effective under this rate for a period of five years from the date of service commencement.

2. The negotiated demand charge shall be increased according to the differential between the negotiated rate and the ceiling as portrayed by the following schedule.

Years	Differential Percent Decrease
1-3	0%
4	25%
5	50%

At the end of the fifth year, the negotiated agreement hereunder expires.

3. Upon expiration of the contract, the customer shall be served under the otherwise applicable rate schedule.

4. Customers and their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

5. The foregoing schedule is subject to Rates 100-112 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.
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State of North Dakota
Electric Rate Schedule

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE
Rate 38

Availability:

In all communities served for power to customers having a demand of 500 Kw or more for its interruptible load available for interruption for up to 100 hours annually. Electric energy for the interruptible load shall be supplied through a separately metered circuit at the same voltage and phase utilized to serve the balance of the customer's electrical load so arranged to allow remote operation by the Company.

Type of Service:

Service under this rate shall be taken by the customer at whatever primary voltage is available at the point of delivery but not less than 2,400 volts. In the event that it is necessary to build a substation on the Company's transmission line to serve the customer, the cost of building the substation shall be a matter of negotiation between the Company and the customer.

Rate:

Basic Service Charge:	~~Specified in the electric service agreement with the Company.~~ $100.00 per month
Demand Charge:	
October – May	$ ~~8.00~~9.35 per Kw
June – September	$~~11.00~~12.35 per Kw
Energy Charge:	~~1.252~~1.203¢ per Kwh

Minimum Bill:

Basic Service Charge plus the Demand Charge (500 Kw minimum).

Payment:

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

Determination of Billing Demand:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 500 Kw. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. The customer shall execute an electric service agreement with the Company which will include~~, among other provisions,~~ a minimum term of service and ~~monthly Basic Service Charge payments to the Company. The monthly Basic Service Charge payments are determined on a customer by customer basis and shall include, but are not limited to,~~ any additional customer costs incurred by Company for facilities, such as substations, electric lines, meters, switching devices, and circuit breakers that are necessary to provide service under this rate.

2. All equipment associated with the interruptible load must be of such voltage and electrical characteristics that it can be separately metered and served from the circuit provided for the interruptible portion of the customer's load. If the equipment to be served is such that this is impossible, the customer must either make special arrangements with the Company or furnish the necessary equipment suitable for connection and metering to the circuit for the interruptible portion of the load.

3. The customer must provide a load-break switch or circuit breaker equipped with electrical trip and close circuits allowing for remote operation of the customer's switch or circuit breaker by the Company. Customer must wire the trip and close circuits into a connection point designated by the Company to allow installation of control equipment by the Company. Customer must provide a continuous 120 volt AC power source at the connection point for operation of the Company's control system.

4. The customer is responsible for the remote terminal unit (RTU) equipment, if applicable, installation and upgrades costs located between the customer's generator, or load control system, and the Company's energy management control system. The Company shall notify the customer when an RTU upgrade is required and the customer shall be given the opportunity to decide whether the RTU upgrade (RTU upgrade event) is installed. If the RTU upgrade is not installed, the customer's Rate 38 service shall be terminated and the customer moved to the otherwise applicable rate.

~~4.~~5. The Company may request the customer to interrupt at any time for up to 100 hours during an annual period beginning June 1 of each year and ending on May 31 of the following year.~~starting with the in-service date of the contract between the Company and the customer and annually thereafter.~~ Company shall reimburse customer for customer's fuel when interrupted at a mutually acceptable level and price.

~~5~~6. Customer will be required to interrupt service within 10 minutes of the Company's signal to interrupt service.

~~6~~7. The penalty for non-performance when the Company requests the customer to interrupt will be the greater of $10.00 per Kw applicable to the Kw demand specified in the electric service agreement with the Company or the appropriate allocation of any penalties imposed on the Company by the Midcontinent Independent System Operator (MISO) ~~west Reliability Organization for~~during the period of non-performance. After a second failure to perform, within a 12-month period, the customer shall be liable for the penalty and may be moved to the otherwise applicable rate.

8. The Company may request a summer and winter performance test each year, lasting up to one hour in length, to test the customer's interruption capability. Scheduled performance tests shall not count against the 100 hour limit in Section 4 above. Two failures to perform, within a 12-month period, may result in the customer being moved to the otherwise applicable rate.

9. Additional terms and conditions may be added or amended from time-to-time with written notice to the customer to comply with MISO's load modifying resource (LMR) eligibility for the Company's utilization. The customer shall have the option of accepting the additional program rules provided by the Company or be moved to the otherwise applicable rate.

~~7.~~10. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

~~8.~~11. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Montana-Dakota Utilities Co.
~~*A Division of MDU Resources Group, Inc.*~~
400 N 4th Street
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State of North Dakota
Electric Rate Schedule

NDPSC Volume ~~4~~5
~~5th Revised~~ Original Sheet No. 25
~~Canceling 4th Revised Sheet No. 25~~

SMALL MUNICIPAL ELECTRIC SERVICE
Rate 40 (CLOSED)

Availability:

For all lighting and power requirements with billing demands of 50 kilowatts or less for public buildings or locations supported by public tax levies, and for which the city is liable for payment, in all municipalities served where the Company is operating under a municipal franchise or permit, and the municipality has a standard contract for operation of a street lighting system and/or a municipal pumping system with the Company.

This rate is restricted to small municipal electric service customers who were served under this rate prior to January 27, 1987. Any new small municipal general electric service customer may take service under another applicable rate.

Rate:

Non-Demand:	
Basic Service Charge:	$~~0.84~~1.15 per day
Energy Charge:	
October – May:	
First 750 Kwh per month	~~3.402~~4.321¢ per Kwh
Over 750 Kwh per month	~~2.302~~3.221¢ per Kwh
June – September:	~~3.402~~4.321¢ per Kwh
Demand:	
Basic Service Charge:	$~~1.00~~1.30 per day
Demand Charge:	
October – May:	
10 Kw or less	No Charge
Over 10 Kw	$ ~~8.25~~12.19 per Kw
June – September:	$~~11.25~~15.19 per Kw
Energy Charge:	~~1.302~~2.221¢ per Kwh

Date Filed: ~~October 8, 2018~~May 16, 2022
Effective Date: ~~Service rendered on and after December 1, 2018~~
Issued By: ~~Tamie A. Aberle~~Travis R. Jacobson
Director - Regulatory Affairs
Case No.: PU-~~18-89~~22-

Minimum Bill:
Basic Service Charge.

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

Determination of Billing Demand:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand in the current month. Demands will be determined to the nearest one-tenth kilowatt. Customers whose loads have rapidly fluctuating and/or intermittent demand characteristics shall be subject to special rules and regulations.

Power Factor Clause:
The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:
Bills are subject to the following adjustments or any amendments or alterations thereto:
1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Customers or their architects, contractors and electricians should consult with the Company before proceeding to design or erect installations in which there will be a substantial electric load, to make sure their equipment will meet requirements and receive adequate service.

2. Customer may take service under the non-demand rate provided customer's monthly Kwh will not exceed 4,000 Kwh per month for four consecutive months or connected load will not exceed 20 Kw.

3. Customers not qualifying for the non-demand rate shall be served under the demand rate.

4. The foregoing schedule is subject to Rates 100-112 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.
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State of North Dakota
Electric Rate Schedule

~~MUNICIPAL~~ PUBLIC LIGHTING SERVICE Rate 41

Availability:

For the ~~municipal~~ lighting ~~purposes including~~ of streets, alleys and other road right of ways~~public grounds~~. Service will be provided all night, every night in the year with a minimum service requirement of 4,000 hours annually ~~and must be covered by written contract~~.

Rate:

Primary Service:
Energy Charge: ~~5.096~~5.180¢ per Kwh

Secondary Service:
Energy Charge: ~~5.596~~5.680¢ per Kwh

~~Discount: For contracts of ten years or more 10%~~
Kwh shall be computed according to the total rated capacity of lamps in use.

Facilities Charge per unit per month:

LED, Overhead Conductor, Distribution Pole	$5.40
LED, Overhead Conductor, Street Light Pole	$10.50
LED, Underground Conductor, Distribution Pole	$7.10
LED, Underground Conductor, Street Light Pole	$12.20
Wood Lift Pole	$7.00

~~**Minimum Bill:**~~

~~As provided in contract.~~

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. The Company will maintain the Company-installed and owned facilities when notified by customer or noticed by Company personnel. ~~and change the light bulbs when notified by the municipality that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of employees of the municipality.~~ In case of vandalism, malicious mischief, or willful negligence the Company will charge the ~~municipality~~customer for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. In ~~municipally~~customer-owned street lighting systems, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

4. When service is not metered, the energy usage ~~bill~~ shall be computed on a~~n~~ ~~annual~~ daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to the customer. ~~one-twelfth shall be payable each month.~~

5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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State of North Dakota
Electric Rate Schedule

MUNICIPAL PUMPING SERVICE Rate 48

Availability:

For municipal pumping purposes provided the municipality uses electricity exclusively for all its pumping requirements and purchases all such electricity from the Company. The municipality must sign a contract for a minimum period of one year.

Rate:

Primary Service:

Basic Service Charge: $80.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$~~6.00~~9.00 per Kw
June – September:	$~~9.00~~12.00 per Kw

Energy Charge: ~~1.798~~1.826¢ per Kwh

Secondary Service:

Basic Service Charge: $45.00 per month

Demand Charge:

Connected loads of 10 Kw or less will be billed based on connected load. Connected loads in excess of 10 Kw will be billed based upon the greater of the highest 15 minute interval demand as registered upon a demand meter in the current month or 10 Kw.

October – May:	$~~6.00~~9.00 per Kw
June – September:	$~~9.00~~12.00 per Kw

Energy Charge: ~~1.898~~1.926¢ per Kwh

Discount: For contracts of ten years or more 10%

MUNICIPAL PUMPING SERVICE Rate 48

Minimum Bill:

Basic Service Charge plus Demand Charge.

Payment:

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

Power Factor Clause:

The Company reserves the right to require the customer to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

2. The foregoing schedule is subject to Rates 100-112 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~~

OUTDOOR LIGHTING SERVICE Rate 52

Availability:

For all outdoor lighting including flood lights, billboard lighting, ~~metallic vapor~~ yard lights, and Christmas lights in all communities served. Lighting equipment may be Company-owned or customer-owned.

Rate:

Primary Service:

Energy Charge: ~~6.357~~6.766¢ per Kwh

Secondary Service:

Energy Charge: ~~6.763~~7.172¢ per Kwh

Kwh shall be computed according to the total rated capacity of the units in use.

Payment:

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

Adjustment Clauses:

Bills are subject to the following adjustments or any amendments or alterations thereto:

1. Renewable Resource Cost Adjustment Rate 55
2. Generation Resource Recovery Rider Rate 56
3. Environmental Cost Recovery Rider Rate 57
4. Fuel and Purchased Power Adjustment Rate 58
5. Transmission Cost Adjustment Rate 59

General Terms and Conditions:

1. Applicable to Company-owned Facilities:
   a. The Company will install, own and operate the flood light(s), and yard light(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dusk to dawn.

b. The light may be mounted on existing poles owned or controlled by the Company. ~~The Company will furnish a 35 foot pole(s) for flood lights and a 30 foot pole(s) for yard light(s) at the customer's request at a separate rental rate if a special setting is required. If the customer chooses, t~~ The light may be installed on a pole owned by the customer or other mounting point suitable for installation of the light. The conductors will be extended 100 feet per unit free of charge, but the customer shall pay for the extra cost of extensions of more than 100 feet per unit.

c. To the rate stated herein, ~~bulb~~ fixture replacement and ownership costs for the units shall be added. The customer should consult with the Company for such costs.

d. The Company will maintain the Company-installed and owned facilities when notified by customer or noticed by Company personnel. ~~and change the light bulbs when notified by the customer that they are burned out except when the facilities are damaged or destroyed by vandalism, malicious mischief by third parties, or willful negligence on the part of the customer~~. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

2. Primary service rate is applicable to customers that own their own transformers, related equipment and distribution facilities downstream of the meter, satisfactory to the Company so customer can receive service and be metered at primary voltages of 2,400 volts or greater.

3. For customer-owned outdoor lights, an additional charge will be made to cover lamp replacements, materials and labor whenever such services are supplied by the Company.

~~3~~4. When service is not metered, the bill shall be computed on a~~n annual~~ daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to customer.~~one-twelfth shall be payable each month.~~

~~Metallic vapor ratings in lumens shall be converted to watts on the basis of the published ratings currently issued by the General Electric Company and the Westinghouse Electric Corporation.~~

~~4~~5. The foregoing schedule is subject to Rates 100-112 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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~~Renewable Resource Cost Adjustment~~ RENEWABLE RESOURCE COST ADJUSTMENT Rate 55

1. **Applicability:**
This rate schedule represents a Renewable Resource Cost Adjustment (RRCA) and specifies the procedure to be utilized to recover the jurisdictional costs associated with renewable generation resource modifications or additions approved by the Commission, but not recovered through retail rates. Costs to be recovered may include operation and maintenance expenditures, depreciation, taxes, and a current return on the project costs.

2. **Renewable Resource Cost Adjustment:**
   a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the RRCA rates. The return component of the revenue requirement calculation will include the return on equity established in the Company's most recent rate case.
   b. The RRCA is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express RRCA applicability, and are allocated amongst the rate classes based on the Company's Demand/Energy Factor No. 3 established in the Company's most recent general rate case.
   c. The RRCA will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.
   d. A true-up will reflect any over or under collection of revenue under the RRCA based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Renewable Resource Cost Adjustment:**

Residential & Small General	0.899¢ per Kwh
Large General	0.838¢ per Kwh
Lighting	1.161¢ per Kwh

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Applicability:
This rate schedule represents a Generation Resource Recovery Rider (GRRR) and specifies the procedure to be utilized to recover the jurisdictional costs associated with generation resource additions approved by the Commission but not recovered through retail rates and financial incentives for power purchase agreement eligible for recovery under NDCC 49-06-02 subpart 4. Costs to be recovered may include operations and maintenance expenditures, depreciation, taxes, power purchase agreement financial incentives, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

1. Generation Resource Recovery Rider:

a. The North Dakota jurisdictional GRRR revenue requirement will be allocated to the customer classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case. The adjustment applied to the Residential, Small General Service and Lighting Classes will be calculated based on the customer class revenue requirement and the forecasted Kwh for the forecasted period. The adjustment applied to the Large General Service Class will be calculated based on the customer class revenue requirement and the forecasted demand for the forecasted period and expressed as a KW charge. The return component of the revenue requirement calculation will include the authorized return on equity specified in Case No. PU-~~16-666~~22-____.

b. The GRRR is applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express GRRR applicability, and are allocated amongst the rate classes based on the applicable demand factor.

c. The GRRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this schedule.

d. A true-up will reflect any over or under collection of revenue under the GRRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

2. Generation Resource Recovery Rider:

Residential & Small General	~~0.185~~0.422¢ per Kwh
Large General	~~54.680~~125.361¢ per KW
General Space Heating Rate 32	~~23.976~~59.323¢ per KW
Lighting	~~0.091~~0.131¢ per Kwh

~~Environmental Cost Recovery Rider~~ENVIRONMENTAL COST RECOVERY RIDER
Rate 57

1. Applicability:
This rate schedule represents an Environmental Cost Recovery Rider (ECRR) and specifies the procedure to be utilized to recover the jurisdictional costs to be incurred by the Company in complying with federal and state environmental mandates determined to be eligible for recovery under NDCC 49-05-04.2. Costs to be recovered may include capital expenditures, depreciation, taxes, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

2. Environmental Cost Recovery Rider:

a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the ECRR. The return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case.
b. The ECRR is applicable to all retail customers for electric energy sold, except those served under special contracts, and are allocated amongst the rate classes based on the Company's Demand Factor No. 2 established in the Company's most recent general rate case.
c. The ECRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be eligible under NDCC 49-05-04.2.
d. A true-up will reflect any over or under collection of revenue under the ECRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. Environmental Cost Recovery Rider:

Residential and Small General	0.000¢ per Kwh
Large General	0.000¢ per Kwh
Lighting	0.000¢ per Kwh

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

~~**State of North Dakota**~~
~~**Electric Rate Schedule**~~

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~~**Date Filed:**~~	~~June 26, 2017~~	~~**Effective Date:**~~	~~Service rendered on and after August 7, 2017~~
~~**Issued By:**~~	~~Tamie A. Aberle~~ ~~Director - Regulatory Affairs~~	~~**Case No.:**~~	~~PU-16-666~~

FUEL AND PURCHASED POWER ADJUSTMENT Rate 58

1. **Applicability:**
This rate schedule sets forth the procedure to be used in calculating the Fuel and Purchased Power Adjustment (FPPA). It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power as allocated to North Dakota; and (b) amortization of the Deferred Fuel Cost Account.

2. **Effective Date and Limitation on Adjustments:**
   a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Purchased Power Adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Deferred Fuel Cost Account shall be April 1 of each year.

   b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of electric supply only when the amount of change in such adjustment is at least .001 cents per Kwh. The adjustment to be effective April 1 shall be filed each year, regardless of the amount of the change.

3. **Fuel and Purchased Power Adjustment:**
   a. The monthly Fuel and Purchased Power Adjustment shall be calculated separately for primary service and secondary service customers and shall reflect Montana-Dakota's cost of fuel and purchased power plus the annual Surcharge Adjustment.

   b. The cost of fuel and purchased power shall be calculated separately for primary service customers and secondary service customers, and shall be the sum of the following costs for the most recent four month period, as allocated to North Dakota and to the primary and secondary customer classes:

      1. The cost of fossil and other fuels and reagents, including sand, recorded in Account Nos. 501, 502 and 547.

2. Natural gas and pipeline reservation charges recorded in Account No. 547

3. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in the wholesale electric energy markets as recorded in Account No. 555

4. Capacity purchases as recorded in Account No. 555.

5. Regional Market Administration expenses recorded in Account No. 575.

6. Less 100 percent of the wholesale sales revenue.

7. Less the revenue from the sales of Renewable Energy Credits (RECs).

c. The cost per Kwh for the month is the sum of 3(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes.

4. Surcharge Adjustment:
All sales rate schedules shall be subject to a Surcharge Adjustment to be effective on April 1 each year. The Surcharge Adjustment per Kwh sold shall reflect the amortization of the applicable balance in the Deferred Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

a. The balance in the Deferred Fuel Cost Account (Account 182.3) includes:

1. The current month over or under recovery, determined as follows:

i. Montana-Dakota shall determine each month the cost for that month's fuel and purchased power.

ii. Montana-Dakota shall subtract from the month's cost determined in 4.a.1.i the revenue collected under the Fuel and Purchased Power Adjustment for that month.

FUEL AND PURCHASED POWER ADJUSTMENT Rate 58

iii. The resulting difference (positive or negative) shall be included separately for primary and secondary service classes.

2. Refunds from supplier(s) and market operators with respect to fuel and purchased power costs.

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

5. Manner of Filing:
The Company shall file a monthly statement showing the calculation of the Fuel and Purchased Power Adjustment with the Commission prior to implementing the monthly adjustment. The adjustment in rates shall be effective with service rendered on and after the first day of each month, unless the Commission shall otherwise order.

6. Fuel and Purchased Power Adjustment:
The current and historical Fuel and Purchased Power Adjustment for primary and secondary service customers can be found at www.montana-dakota.com/rates-and-services.

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

State of North Dakota
Electric Rate Schedule

TRANSMISSION COST ADJUSTMENT Rate 59

1. Applicability:

This rate schedule represents a Transmission Cost Adjustment (TCA) and specifies the procedure to be utilized to recover the net balance of the capital and operating costs and revenue credits of Montana-Dakota's transmission related expenses and revenues determined to be eligible for recovery in accordance with 49-05-04.3 NDCC. Costs to be recovered under the Transmission Adjustment shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

2. Transmission Cost Adjustment:

a. An adjustment per Kwh will be determined based on the cumulative transmission related costs and revenue credits eligible for recovery and as allocated to the North Dakota jurisdiction and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

b. The adjustment will be applicable to all retail customers for electric energy sold, except those served under special contract, where the contract does not express TCA applicability, and allocated among the rate classes based on the transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case.

c. The adjustment per Kwh will be revised annually to reflect the current level of costs to be recovered.

d. The true-up will reflect any over or under collection of revenue under the Transmission Adjustment from the preceding twelve month period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. Transmission Cost Adjustment Rate by class:

Residential & Small General	0.801¢ per Kwh
Large General	0.636¢ per Kwh
Lighting	0.360¢ per Kwh

Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating occasional electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 100 Kw or less, that are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$0.05 per day
With instrument transformers:	$0.19 per day
Metering charge for three phase service:	$0.12 per day
With instrument transformers:	$0.33 per day

Energy delivered to and accepted by Company by a QF shall be paid for by Company in accordance with one of the following two options, elected by the QF:

1. Simultaneous Purchase and Sale:
   Energy sales to QF - Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

   Energy purchases by Company:

   Energy Payment = 2.145¢ per Kwh

2. Net Billing:
   Energy generated will be compensated on a net billing basis. The Company will install a meter to measure the energy generated by the QF. The Company will also install a meter to measure the energy consumed by the QF. Metered generation will be subtracted from the metered consumption for the billing period.

If metered generation is less than metered consumption, the QF will be billed the applicable retail rate. If metered generation is greater than the metered consumption, the QF will be paid for each Kwh at an amount equal to:

2.145¢ per Kwh

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.
2. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.
3. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.
4. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be at least one year but less than five years.
5. In order to qualify for the net billing option, the generating equipment and the load of the facility must be located at the same "physical site". "Physical site" shall mean on the same tract of land and the generator output must be physically connected to the load service entrance.
6. For general terms and conditions covering QF's, see Rate 140.
7. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

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State of North Dakota
Electric Rate Schedule

PARALLEL GENERATION PEAKING FACILITY
PURCHASE Rate 96 TIME DIFFERENTIATED

Availability:

To any qualifying cogeneration and small power production facilities for the purpose of generating electric energy in parallel with the Company's system. This schedule is applicable to cogeneration and small power production facilities with a design capacity of 1000 Kw or less, that operate as a peaking facility (defined below), and are Qualifying Facilities (QF) as defined under 18 CFR, Part 292.

Rate:

Metering charge for single phase service:	$ 0.16 per day
With instrument transformers:	$ 0.30 per day
Metering charge for three phase service:	$ 0.18 per day
With instrument transformers:	$ 0.38 per day

1. Capacity delivered to the Company:

   Monthly capacity payments for a QF (not registered as a MISO generator) shall be assigned by Montana-Dakota based upon the amount of qualifying capacity assigned to an eligible resource under BPM-011 Resource Adequacy of the MISO tariff subject to adjustment annually in accordance with BPM-011.

   Monthly capacity payments for a MISO-registered QF shall be based on the capacity credits assigned by MISO on an annual basis.

   Monthly capacity payment shall be the MISO capacity auction clearing price for Zone 1. The capacity payment is subject to change annually through the year 2030. Effective in 2031 the monthly capacity payment shall be $9.655 per Kw applicable for the remainder of the term of the contact.

   Capacity payments will be paid in the subsequent billing period.

2. Energy Payment:

ON-PEAK	OFF-PEAK
2.072¢ per Kwh	2.139¢ per Kwh

Peak Periods: The On-Peak Period is defined as those hours between 12 p.m. and 8 p.m. local time, Monday through Friday in the months of June through September. The Off-Peak Period is defined as all other hours. Definitions of On-Peak and Off-Peak periods are subject to change with change in the Company's system operating characteristics.

Energy Sales to Qualifying Facilities:

Service provided to such customers by the Company shall be billed at the appropriate rate, by class of customers (i.e., residential, small and general electric service, etc.) that is currently on file with the Commission.

General Terms and Conditions:

1. Change of Rates: This schedule shall be reviewed annually, updated if necessary, and revised upon the Commission's approval.

2. Service under this schedule shall be on a simultaneous purchase and sale basis only.

3. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill and pay in accordance with the charges and payments contained in this rate schedule.

4. The customer shall, with prior written consent of the Company, furnish, install and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

5. A written contract with the Company shall be signed stipulating the terms and conditions of the interconnection and sale of the electricity to the Company. The term of the contract hereunder shall be five years or more.

6. Line loss considerations will be determined on a site specific basis.

7. For dispatchable units, generator outages must be pre-scheduled with Company to provide coordination with Company units.

8. A Peaking Unit is a unit not designed for continuous operation and is capable of supplying capacity and energy during periods of peak electric consumption. Generally, peaking units have a capacity factor of 20% or less.

9. For general terms and conditions covering QF's, see Rate 140.

10. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the North Dakota Public Service Commission. Rates charged hereunder may be modified by Company at any time by making a unilateral rate application with the North Dakota Public Service Commission or its successor. The new rates shall be effective upon approval by the Commission.

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TABLE OF CONTENTS
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 (Commission) 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. Also refer to Electric Service Rules & Regulations Rate 110.

II. DEFINITIONS:

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

APPLICANT – A customer requesting Company to provide service.

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

COMPANY – Montana-Dakota Utilities Co.

CUSTOMER – Any individual, partnership, corporation, firm or 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.

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.

III. GENERAL TERMS AND CONDITIONS:

1. RULES FOR APPLICATION OF ELECTRIC SERVICE:
   i. Residential Electric Service is available to any residential customer for domestic purposes only. All normal sized equipment used for domestic lighting, heating, cooking and power, and used strictly for household purposes, may be supplied through one meter.

      a. Residential service is defined as service for domestic general household purposes in space occupied as living quarters, designed for occupancy by one family. Typical service would include the following: separately metered units, such as single private residences, single apartments, mobile homes and sorority and fraternity houses (this is not an all-inclusive list). In addition, auxiliary buildings on the same premise as the living quarters, used for residential purposes, may be served on the residential rate. Where premise is defined as a contiguous parcel of land undivided by a dedicated street, alley, highway, or other public thoroughfare or railway.

      b. Motors and other equipment which interfere with service to neighboring customers, all motors larger than 5 horsepower and temporary or seasonal loads totaling more than 25 kilowatts (Kw) will not be permitted on the Residential Electric Service Rate without prior Company approval.

      c. Only single phase service is available under the Residential Electric Service Rate.

   ii. Three phase service shall be served under the appropriate General Electric Service Rate.

   iii. General Electric Service is defined as service provided to non-residential services, such as 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 parlors, apartment houses with master metering exemptions, 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).

iv. If separate metering is not practical for a single unit (one premise) that is using electricity for both domestic purposes and for conducting business (or for nonresidential purposes), 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 General Electric Service) applicable to the type of service which constitutes 50% or more of the total connected load.

v. 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 appropriate General Electric Service Rate.

2. CONSUMER DEPOSITS:
The Company will determine whether or not a deposit shall be required of an applicant for electric service in accordance with Commission rules.

i. The amount of such deposit shall not exceed an estimated 60 day service bill.

ii. 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 or 30

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.

iii. 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.

iv. Deposits shall be refunded to customers at termination provided all billings for service have been paid. Deposits will be refunded to all active customers, after the deposit has been held for 12 months, provided a prompt payment record has been established.

3. LATE PAYMENT CHARGE:
Bills will be considered past due if not paid by the due date shown on the bill. An amount equal to 1% per month will be applied to any past due balance.

4. 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.

5. 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.

~~5.~~6. TAX CLAUSE:
In addition to the charges provided for in the electric 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.

~~6.~~7. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS:
For service requested by customers after the Company's normal business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and materials at retail prices.

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

~~7.~~8. RECONNECTION FEE FOR SEASONAL CUSTOMERS:
A charge will be collected for reconnecting electric service to a customer who requests reconnection of service, at a location where the same customer discontinued the same service during the preceding twelve-month period.

Applicable Charge:

i. Customers with non-demand meters:	$20.00
ii. Customers with demand meters:	$40.00

~~8.~~9. DISCONTINUANCE OF SERVICE FOR NONPAYMENT OF BILL:

i. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(1), the Company may disconnect service if the customer is delinquent in payment for service, and fails to pay for service or enter into a satisfactory installment agreement with the Company for payment within ten (10) days of the Company giving the customer written notice of the Company's intention to discontinue service on account of payment delinquency.

ii. All bills for service are due when rendered and will be considered delinquent if not paid by the due date shown on the bill. If any customer shall become delinquent in the payment of service bills, such service may be discontinued by the Company under the applicable rules of the Commission.

iii. If a customer's credit standing becomes unsatisfactory after a deposit has been refunded or if the deposit is inadequate to cover the estimated charge for furnishing service for a 60-day period, a new or additional deposit may be required upon reasonable written notice by the Company.

iv. Pursuant to North Dakota Administrative Rules 69-09-02-05.1(10), the Company may not discontinue service to the Customer for nonpayment of a deposit.

v. The Company may collect a fee of $20.00 before restoring electric service which has been discontinued for nonpayment of service bills, or where a Service Extender has been installed in lieu of full disconnection.

~~9.~~10. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILLS:
The Company reserves the right to discontinue service for any of the following reasons:

i. In the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or service to others.

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

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

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

v. 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 $20.00 before restoring electric service, which has been disconnected for the above causes.

~~10.~~11. BILL DISCOUNT FOR QUALIFYING EMPLOYEES:
A bill discount may be available for residential use only in a single family unit served by Montana-Dakota Utilities Co. to qualifying retirees of MDU Resources and its subsidiaries. The bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

~~11.~~12. METHOD OF COMPUTING INITIAL OR FINAL BILLS FOR ELECTRIC SERVICE FOR LESS THAN A FULL MONTHLY BILLING PERIOD:
Customer's meters are read as nearly as practicable at thirty day intervals. When service is begun or terminated at any location between regular meter reading dates, bills will be prorated on a daily basis, whenever the billing period is less than 27 calendar days or more than 35 calendar days. The minimum monthly bill, basic service charge, kilowatt hour blocks and demand charge provisions in all rate schedules will be prorated.

~~12.~~13. SELECTIVE TESTING PLAN FOR METERS:
The electric meter population shall be tested in accordance with the Electric Meter Testing Program approved by the Commission.

~~13.~~14. BILLING ADJUSTMENTS:
If a meter or billing error results from 1) an inaccurate meter; 2) an Incorrect reading of the meter; 3) an incorrect application of a rate schedule; 4) an incorrect connection of the meter; 5) an application of an incorrect multiplier or constant; or 6) other similar errors affecting customer bills.

i. If a Customer is underbilled, the Company may recalculate the bills and reissue corrected bills for service during the period of the error, up to a maximum period of six years from the date of the bill, with the exception of a meter equipment failure.

ii. If a Customer is overbilled, the Company shall recalculate bills for errors resulting in overcharges up to a maximum of six years from the date of payment, with the exception of a meter equipment failure. In the case of a meter equipment failure, the Company may charge the Customer for a period equal to one-half the time elapsed since the last previous meter test, but not to exceed six months.

~~14.~~15. MODIFICATION OF RATES, RULES AND REGULATIONS:
Company reserves the right to modify its rates, rules, and regulations or other provisions now or hereafter in effect, in any manner permitted by law.

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

~~**State of North Dakota**~~
~~**Electric Rate Schedule**~~

~~Reserved for Future Use~~

~~**Date Filed:**~~	~~June 20, 2013~~	~~**Effective Date:**~~	~~Service rendered on and after August 1, 2013~~
~~**Issued By:**~~	~~Tamie A. Aberle~~ ~~Director of Regulatory Affairs~~	~~**Case No.:**~~	~~PU-13-385~~

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC SERVICE
RULES and REGULATIONS

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101. Definitions

Company – Montana-Dakota Utilities Co.

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

102. Purpose

These rules are intended to define good practice which can normally be expected, but are not intended to exclude other generally 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 Regulatory Commissions 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.

103. Customer Obligation

103.1 Application for Service – A customer desiring electric service must submit an 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 service 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 electric service 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 electric service until notified by the 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 necessary.

103.2 Access to Customer's Premises – Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incidental to the service.

103.3 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.

103.4 Relocated Facilities – Where Company facilities are located on or adjacent to a customer's premises where there is an encroachment(s) to electric facilities the customer shall be charged for line relocation on the basis of actual costs incurred by the Company including any required easements.

103.5 Notification of Unsafe Conditions – The customer shall immediately notify the Company of any unsafe conditions associated with the Company's electric facilities at the customer's premises.

103.6 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.

104. Liability

104.1 Continuity of Service – The Company's electric system is unusually widespread and has many interconnections with sources of power other than its own generating stations and it is subject to exposure by storms and other factors not under its control. The Company employs the latest developments in equipment and methods of operation for the purpose of maintaining adequate service. The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of electric service and will not be liable for any loss, injury, death or damage resulting from or caused by the interruption of the same.

104.2 Customer's Equipment – Neither by inspection or rejection, nor in any other way does the Company give any warranty, expressed 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, leased by the customer from third parties or used on the customers premise. It is the obligation of the customer to consult with the Company regarding available maximum fault current and to provide such protection devices as may be necessary to safeguard the equipment and installation from interruptions, variation in voltage and frequency, single-phase energization of three-phase lines, reversal of phase rotation or other abnormal conditions. (Refer to Paragraph 710)

104.3 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 electricity 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.

104.4 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.

104.5 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.

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 electric lines, animal interference, sudden partial or sudden entire failure of electric transmission or 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.

105. Electrical Codes and Ordinances

The Electric Service Rules and Regulations contained herein are supplementary to and do not intentionally conflict with nor supersede the latest edition of the National Electrical Code, the National Electrical Safety Code, nor such state and municipal laws and ordinances that may be in effect in the areas in which the Company furnishes electric service, except that where the requirements of these Electric Service Rules and Regulations exceed those of such codes, laws, and ordinances, these Electric Service Rules and Regulations shall apply. Existing installations, including maintenance replacements, that currently comply with prior revisions of these rules and regulations, need not be modified to comply with these rules except as may be required for safety reasons.

106. Wiring Adequacy

Wiring codes provide minimum requirements for safety. Installation of wiring capacity greater than minimum code requirements is recommended to bring to the customer all the benefits of electric service and to protect building investment by minimizing obsolescence resulting from an inadequate wiring system.

107. Inspection of Wiring
Where permits and inspections covering customer's wiring and installation are required by local ordinance, it is mandatory that such requirements be fulfilled before the Company will make connections to the customer's installation. In locations where such inspections are not required by law or ordinance, an affidavit by the wiring contractor stating that the wiring has been done in compliance with the National Electrical Code will be acceptable.

108. Permits, Certificates, Affidavits
It is the responsibility of the customer to obtain all necessary permits, certificates of inspection or affidavits as required in Paragraph 107 above and to notify the Company promptly of any proposed alterations or additions to customer's load. Failure to comply with these requirements may result in delayed connection, interruption of service or damage to apparatus.

109. Consultation with the Company
109.1 The location, size and character of the customer's load and the current, voltage, frequency, phases, etc. which the Company has available at the customer's location will determine the type of service supplied to the customer.

109.2 Architects, engineers, contractors, electric dealers, wiremen and others must confer with local representatives of the Company to determine the type of service that will be available before designing or preparing specifications for new electrical installations or alterations to existing installations.

109.3 In all cases involving large installations and other cases where any doubt exists, full information as to the type of service available should be obtained from the Company.

110. Unauthorized Use of Service
110.1 Unauthorized use of service is defined as any deliberate interference that results in a loss of revenue to the Company. Violators are subject to prosecution.

110.2 Types of unauthorized use of service include, but are not limited to, the following:
- (a) Bypass around meter.
- (b) Meter reversed.
- (c) Equipment connected ahead of meter.

(d) Tampering with meter that affects the accurate registration of electric usage.
(e) Electricity being used after service has been discontinued by the Company.

110.3 In the event that there has been unauthorized use of service, customer shall be charged for:
(a) All costs associated with investigation or surveillance;
(b) Estimated charge for non-metered electricity;
(c) All time to correct situation;
(d) Any damage to Company property.

110.4 A customer's service disconnected for unauthorized use of service shall be reconnected after the customer has furnished satisfactory evidence of compliance with Company's rules and conditions of service, and paid any charges which are due, including:
(a) All delinquent bills, if any;
(b) The amount of any Company revenue loss attributable to said tampering;
(c) Expenses incurred by the Company in replacing or repairing the meter or other equipment, costs incurred in the preparation of the bill, plus costs as outlined in Paragraph 110.3;
(d) Applicable reconnection fee;
(e) A cash deposit, the amount of which will not exceed the maximum amount determined in accordance with rules of the applicable State Public Service or Utilities Commission.

111. Unauthorized Attachments to Poles

111.1 The unauthorized attachment of any flags, banners, signs, clotheslines, antennas, etc. to Company poles is prohibited. The use of poles for placards or other advertising matter is forbidden. The Company will remove such unauthorized attachments without notice and may prosecute any such trespassers.

111.2 Customers are cautioned to locate antennas so that they are beyond falling distance from the Company's lines, either transmission or distribution. Antennas and lead-ins shall be located a safe distance from and shall never cross over or under the Company's lines or contact the Company's poles. The Company disclaims all responsibility where such equipment contacts the Company's lines, poles or equipment.

Section 200 - USE OF ELECTRIC SERVICE

201. Rate Schedules
Electric service will be billed under the rate schedule that applies to the class of service used. Rate schedules applicable to various classes of service may be obtained from the Company upon request.

202. Resale of Energy
The Company will not supply energy for resale except as expressly covered by special contract or where such provision is a part of the rate schedule.

203. Temporary Service
Temporary service is any service for construction work, carnivals, gravel pits, occasional lighting, etc., which is not expected to continue in use for a period long enough to justify the construction cost necessary for extending service. When temporary service is desired the customer shall, in addition to paying the scheduled rates, make deposit in advance in the amount of the Company's estimated cost of installing and furnishing such temporary service facilities together with the cost of disconnecting and removing same and the estimated billing to the customer for electric service. Final billing will reflect credit for the salvage value of materials used in providing the temporary service. Any deficiency in such advance payment shall be paid by the customer upon presentation of a bill by the Company. Any amount deposited in excess of final billing by the Company will be refunded to the customer.

204. Standby Service
Where electric service is supplied as standby to a customer's generating facilities or vice versa, the customer shall provide and install at the customer's expense a suitable double-throw switch or other device which will completely isolate the customer's power facilities from the Company's system. The service entrance shall be installed so that the phase conductors will be totally isolated from the customer's wiring before the standby unit is put into operation.

205. Parallel Service
Parallel operation of the customer's generating equipment with the Company's system shall be permitted to the extent provided in other approved rates.

206. Transformer Installations on the Customer's Premises

206.1 The Company will supply transformers to be installed on the customer's premises when requested by the customer and in accordance with the following paragraphs.

206.2 The customer shall agree to indemnify and save the Company harmless from any loss, damage, expense or liability, incurred or arising from, or out of the installation, operation, maintenance, repair or removal of its transformers, cables, conductors, apparatus and all other Company property, material or equipment placed on the customer's premises.

206.3 Company's power or distribution transformers will not be installed in the customer's building.

206.4 The Company will furnish, own and maintain conventional oil filled transformers at no cost to the customer. However, where dry type transformers, transformers containing a nonflammable insulating coolant or oil filled transformers of special voltage or design are required they shall be owned, installed and maintained by the customer at the customer's expense.

206.5 Padmount transformers may be installed on customer's premises. The customer shall furnish a suitable concrete pad, conduit, ground rod and service conductors as noted in Figure 5. Where the customer has more than four parallel conductors, a cable junction enclosure and conduits to the transformer location may be required. The customer shall consult with the Company to determine when a cable junction enclosure is required.

206.6 Where the transformer is installed adjacent to an asphalt or concrete driveway, parking lot, or walkway, the customer shall provide conduit from the transformer location to a point beyond the driveway, parking lot, or walkway to accommodate the Company's primary voltage cable. The customer shall provide barriers and clear zones to protect transformer from damage and to allow proper cooling and access to conductor compartments. The customer shall consult with the Company to determine the proper size conduit and protective barriers.

206.7 Refer to Figure 5 for additional information on transformer location.

207. Overhead to Underground Primary Conversion

When requested by property owners, underground distribution and services will be provided to replace existing overhead distribution to a group of owners cooperating with one another, providing:

(a) There exists a sufficient number (25) of homes on contiguous lots that are available for the conversion. At the Company's option, smaller groups could be acceptable.

(b) The terrain and other soil conditions are suitable for installation of underground facilities.

(c) Easements will be granted at no cost to the Company, wherever installed facilities are on private land.

(d) The customer, at customer's expense, must adapt the customer's electrical facilities to accept an underground service.

(e) The customer, or group of customers, provide payment for the cost of removal of overhead facilities and total installed cost, multiplied by the fractional life remaining, less the salvage value of the removed equipment. The customers may also be required to reimburse the company for other reasonable and prudent costs in excess of the Company's standard installation that result from the installation of the requested underground distribution.

Section 300 - ELECTRIC SERVICE AVAILABLE

301. Frequency

All service supplied by the Company is alternating current at a nominal frequency of 60 Hertz.

302. Secondary Voltages (See also Section 400)

302.1 In general, the following classes of service are normally supplied:

Phase	Wires	Nominal Voltage	Nominal Service
1	3	120/240	Single Phase Lighting & Power
3	4 Delta	120/240	Combined Light & Power *
3	4 Wye	208 Grd Y/120	Combined Light & Power
3	4 Wye	480 Grd Y/277	Combined Light & Power **
3	4 Delta	240/480	Combined Light & Power *

*Overhead Primary
**Underground Primary

Note: The Company follows the provisions of ANSI C84.1; latest revision, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

302.2 Only one class of service voltage is provided to a single customer location.

302.3 Service at other voltages may be made available for approved loads upon special application to the Company. Supplying such service may require special construction and equipment by the customer and the Company. The details of such construction and equipment are subject to negotiation between the Company and the customer before service is supplied.

302.4 As the voltage and number of phases which will be supplied depend upon the character of the load, its size, and location, it is necessary that the customer consult with the Company regarding the type of service which will be furnished before proceeding with the purchase of equipment or the installation of wiring. (Refer to Paragraph 109)

302.5 The customer's wiring for single phase installations shall be such that the difference in loads on each side of the supply neutral shall not exceed 10% of the total load.

302.6 For three phase grounded wye installations, the load shall be balanced so that the difference in loads on the separate phases shall not exceed 10% of the total load.

303. Primary Voltages (See also Section 500)
Service may be made available at primary voltage of 2400 volts or higher. The available primary voltage is dependent upon the local primary voltage.

Section 400 - SECONDARY VOLTAGE SERVICE
(Under 600 Volts)

401. Secondary Voltage Service Connections
The location of the service connection is subject to approval by the Company. The Company will cooperate with the customer to the fullest extent practicable in determining such location. Once established, any change by the customer may result in billing to the customer for any additional work or materials required by the Company.

402. Service Connections and Disconnections
All connections or disconnections of overhead or underground services, regardless of the voltage, will be made by the Company at the point where the Company's facilities join those of the customer. No customer or agent of the customer will be authorized to make such connections or disconnections. (Refer to Paragraphs 103.1, 107, and 108.)

403. Number of Service Drops
In general, one service drop will be installed for each customer location. Exceptions will be made in special cases where it is mutually advantageous to the customer and the Company.

404. Services in Raceways
Where services are installed in raceways, the installations must comply with the requirements of the latest edition of the National Electrical Code. In addition, metered conductors shall not be installed in the same raceway as unmetered service conductors.

405. Service Entrance Requirements
405.1 The Company recommends that the service entrance for single family residences be not less than 100 ampere. The service entrance shall be sized and installed in accordance with provisions of the National Electric Code, state code, and local ordinances. Bare neutral wire shall not be installed in metallic conduit due to the possibility of radio interference.

405.2 Ample length of service entrance conductor shall be left protruding from the service head and at padmount equipment facilities to allow for proper connection to the service drop for overhead installations and to padmount equipment terminals.

405.3 When entrances are parallel in two or more conduits, all phases shall be run in each conduit and all wires shall be of the same length.

406. Identification of Conductors
406.1 For purposes of identification, the neutral wire of each single phase entrance shall be clearly marked at the service outlet as well as at the meter location.

406.2 Where 4-wire, three phase service entrances are installed, the neutral conductor and the "wild" phase conductor (nominal 208 volts to ground) shall each be clearly

marked at the service outlet, at the meter and at service equipment.

407. Overhead Service Drops

407.1 The service entrance shall preferably be through the eave and be located so the overhead service drop will be as short as practical and maintain all clearance requirements. (Refer to Figure 1 and Paragraph 407.4)

407.2 In cases where proper clearances cannot be maintained by attaching the service drop directly to the building, the customer shall install and maintain a supporting structure of sufficient mechanical strength to support the wires and of sufficient height to provide the necessary clearances.

407.3 The customer shall furnish and install the necessary facilities for firmly mounting a Company supplied service drop attachment.

407.4 Service drop conductors shall not be readily accessible and when not in excess of 750 volts, shall conform to the following general requirements (refer to the National Electrical Safety Code for possible exceptions):

Clearance over roof – Multiplex service drop conductors shall have the following minimum clearance over a roof:

10.0 feet - from the highest point of roofs or balconies over which they pass with the following exceptions:

Exception 1: The clearance shall be maintained at not less than 3.0 feet above roof or balcony not readily accessible.

Exception 2: Where a roof or a balcony is not readily accessible, and a service drop passes over a roof to terminate at a (through-the-roof) raceway or approved support located not more than 4.0 feet, measured horizontally from the edge of the roof, the clearance above the roof shall be maintained at not less than 1.5 feet for a horizontal distance of 6.0 feet from the raceway or support, and shall be maintained at not less than 3.0 feet for the remainder of the horizontal distance that the cable or conductor passes over the roof.

Note: A roof or balcony is considered readily accessible to a person, on foot, who neither exerts extraordinary physical effort nor employs special tools or devices to gain entry.

Clearance from ground – Multiplex service drop conductors shall have the following minimum clearance from ground:

18.0 feet - over roads, streets and other areas subject to truck traffic. Trucks are defined as any vehicle exceeding 8 feet in height.

18.0 feet - over driveways, parking lots and alleys. This clearance may be reduced to the following values:
- (1) 17 feet - where multiplex service drops cross over or run along alleys, driveways, or parking lots.
- (2) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 14 feet - over residential driveways for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - over residential driveways for drip loops of service drops limited to 150 volts to ground.

14.0 feet - over spaces or ways accessible to pedestrians or restricted traffic only. This clearance may be reduced to the following values:
- (1) If the height of attachment to a building or other installations does not permit these requirements:
  - (a) 12 feet - for multiplex service drops limited to 150 volts to ground.
  - (b) 10 feet - for drip loops of service drops limited to 150 volts to ground.

24.5 feet - over swimming pools, or within 10 feet, measured horizontally, of the pool edge. In addition, there must be 16.5 feet clearance measured in any direction from every point on a diving platform or tower.

The vertical clearance is derived using the latest edition of the National Electric Safety Code rule and, where necessary, adding 2 feet for vertical movement safety factor adopted by Company.

408. Secondary Voltage Underground Service

408.1 Where the customer desires an underground service, the customer must furnish and install conduit from the line side of the meter socket to a point a minimum of 18 inches below grade. (Refer to Figure 1.) The customer shall also provide necessary conduit for services under any asphalt or concrete driveway, walkway, parking lot, or other areas where it is impractical to excavate.

408.2 If a customer requests to convert from an overhead service to an underground service, the customer must provide all necessary changes to the service entrance, including relocation, and the conduit described in 408.1 above. The customer must also provide a Company approved trench ready to accept the underground service conductors including back filling, surface restoration and any future settlement or erosion. If the customer requests the Company to provide this work, the Company will charge the customer for this service. In addition, if the service length is less than 150 feet, a fee equal to the Company's labor and equipment costs to convert the average 100 feet service line will be charged. If the service length is greater than 150 feet the customer will pay a fee equivalent to the Company's labor and equipment costs for the conversion.

409. Mobile Home Service

The customer shall install and maintain the metering pedestal or meter socket and meter mounting device. The customer, as the term is used in this section, is considered to be the mobile home court owner for installations in approved mobile home courts and the mobile home owner for installations on a private lot.

Section 500 - PRIMARY VOLTAGE SERVICE
(2400 Volts or More)

501. General

The Company offers electric service at primary voltages of 2400 volts or higher. A customer desiring to take service at primary voltage shall furnish and own all electrical equipment from the point of delivery and shall consult the Company to assist in determining the size, type and arrangement of service entrance equipment and conductor specifications required for the Customer's particular needs.

502. Service Entrance Equipment

The service entrance equipment shall perform the following functions:

a. Isolate the load from the supply circuit by visible means.
b. Automatically break the circuit in the event of overload.
c. Permit manual opening of the circuit at full load.

503. Overcurrent Protection

The need for overcurrent protective coordination requires consultation with the Company. Overcurrent protective devices may be as follows:

a. Fuses
b. Automatic trip circuit breakers

The overcurrent protective device must have an interrupting rating, at circuit voltage, equal to or exceeding the maximum short circuit current available at the location where service is taken.

504. Disconnecting Means

504.1 The disconnect switch shall provide visible evidence that the circuit to which it is applied is open or disconnected. It shall be located on the supply side of the circuit.

504.2 Where fuses are used, the disconnect switch shall be a gang operated load break switch.

504.3 Where automatic circuit breakers are used as circuit protective equipment, the disconnect switch can be non-load break.

505. Load Balance

Loads on the three phases shall be balanced as closely as possible. The maximum unbalance permitted between individual phase loads is 10% of the total three phase load.

Section 600 – METERING

601. General

The Company will install the necessary meters to measure the electrical energy delivered under each account for a particular class of service.

602. Meter Installations

602.1 The Company will furnish all meters required for billing purposes.
It shall be the customer's responsibility to furnish, install and maintain the meter mounting device. Company approved specifications for electric meter sockets and metering transformer enclosures are listed below:

Self-Contained Meter Sockets – Single-Phase, Three-Phase and Multiple Position Type

1. The customer will utilize meter sockets from a Company approved list of manufacturer and models as posted on the Company's website.
2. U.L. approved, ringless style.
3. 100 ampere minimum for overhead service installations.
4. 150 ampere minimum for underground service installations.
5. Stud connectors are required for all sockets rated 320 amps or greater.
6. For sockets rated below 320 amps, study connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
7. Equipped with a fifth terminal in the nine o'clock position where network metering is required.
8. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
9. A lever by-pass feature is recommended for all residential installations.

Metering Transformer Rated Meter Socket

1. U.L. approved, ringless style with a one piece cover.
2. Minimum size must provide space for test switch installation.
3. Socket must have six terminals for single phase and 13 terminals for all other configurations.
4. Automatic by-pass feature is not acceptable.
5. The customer will utilize instrument rated meter sockets from a Company approved list of manufacturer and models.

Metering Transformer Enclosure (Secondary Service)

1. Recommend a durable, weather-resistant finish and weatherproof seal.
2. Must be provided with hinge-type cover and provisions to attach locking or sealing device.
3. Minimum size 10" x 24" x 30" with suitable mounting brackets for current and voltage transformers.

4. Consult with Company prior to purchasing any metering transformer enclosure.

602.2 Self-contained rated meter sockets shall be placed outdoors.

602.3 On instrument rated meter sockets, the Company will furnish and install the metering transformers. Such meter sockets shall be arranged for outdoor metering. (Refer to Figures 2 and 3.)

602.4 Where a secondary metering transformer enclosure is required, the customer shall furnish and install an enclosure. Such enclosures shall contain only the service entrance conductors and metering transformers. The metering transformers shall be installed on the line side of the customer's disconnecting device. Suitable lugs, connectors, etc. for connecting metering transformers to service mains shall be provided by the customer. (Refer to Paragraph 602.1)

602.5 For installations having switchboards, the metering transformers may be mounted in the switchboard bus, provided they are accessible for changing and testing. Metering transformers shall be mounted on the source side of the main switch.

602.6 Meters and test switches may be mounted on a suitable unhinged panel adjacent to the metering transformer enclosure.

602.7 No device other than a Company-owned or Company-approved device shall be placed into or ahead of the meter socket.

603. Meter-Switch-Fuse Wiring Sequence

For all secondary voltage metering installations the meter, entrance switch and main line fuse or breaker shall be installed in the order named with respect to power flow. All circuits downstream from the meter shall have proper overcurrent protection devices. Additionally, for 480 volt installations, ~~A~~a customer-owned, non-fused, main service switch shall be installed on the source side of all 480 volt, self-contained meters. This switch shall be located no closer than three feet either left or right of the meter socket, and the switch cover is sealed by the Company. The switch shall be labeled “Utility Disconnect”. By exception and upon consultation with the Company, an overcurrent circuit breaker may be installed ahead of a gang style metering installation with 6 or more sockets as an Emergency Disconnect. Access to the Emergency Disconnect Switch shall be lockable and shall be locked by the Company.

604. Meter Locations

604.1 Each meter shall be located outdoors in a place of convenient access where it will not create a hazard. The location shall be agreed upon by the customer's representative and the Company. (Refer to Figure 1.)

604.2 Meters shall be located so that there is not less than 3 feet of unobstructed space, from the ground up, in front of the meter so that the center line of the meter is not less than 4 feet nor more than 5 feet above the floor, ground, or permanent platform from which the reading will be taken. On group installations, the minimum height is 2 feet - 6 inches and the maximum is 6 feet. The minimum center spacing between meter sockets shall be 7 ½ inches horizontally and 8 ½ inches vertically.

604.3 Meter Sockets shall be permanently mounted on secure structures such as houses, buildings, poles, etc. All required conduit will be provided by customer. (Refer to Figures 1, 2, and 3.)

604.4 Enclosures shall not be placed over the meter socket unless approved by the Company.

605. Indoor Metering

Meters shall be located outdoors as noted in Paragraph 604.1. However, depending on the circumstance and after consulting with the Company, locating the meters indoors may be approved on a case by case basis. Where approved, indoor meters for multiple dwellings, large office buildings, etc. shall be grouped and located as near the service entrance location as practicable. In the event such location renders the automatic meter reading equipment ineffective customer will be responsible for costs associated with remedying the situation.

606. Wiring Diagrams

Typical wiring diagrams for various types of self-contained meters are shown on Figure 4. These are subject to change from time to time with advancement in available metering equipment.

607. Labeling

Where two or more meter mounting devices are installed at one location, each shall be labeled so that it may be identified as to the customer served. Electrical contractors are requested and cautioned to check and identify wiring circuits carefully to avoid metering errors due to incorrect circuitry. Permanent (mechanically fastened) engraved plates

shall be placed on the exterior of the meter base on a non-removable panel.

608. Seals
All meters and all points of access to customer wiring on the source side of the meter will be sealed by the Company. All cabinets and switch boxes, either inside or outside of the building which contain unmetered wires, shall have provisions made for sealing before service will be supplied.

Section 700 - UTILIZATION EQUIPMENT

701. Interfering Loads
Whenever a customer's utilization equipment has characteristics which cause undue interference with the Company's service to other customers, the customer shall provide, at customer's expense, the necessary equipment to prevent or eliminate such interference. The Company may install and maintain at the customer's expense the necessary equipment to eliminate such interference if it deems it advisable. When a customer's equipment or method of operation causes such interference and the customer does not correct the condition after being so requested by the Company, the Company reserves the right to discontinue the electric service, following written notification of its intent to do so; and service will not be re-established until the conditions complained of have been corrected.

702. Voltage Flicker and Harmonics
702.1 The Company uses the latest revision of the IEEE Standard 141 as the guideline for the maximum allowable voltage flicker that can be caused by a customer's load as measured at the point of metering. This guideline refers to the momentary dip in voltage that may result from the customer's operation of switches, starting of motors, etc.

702.2 Customer's electric load shall comply with the recommendations within Section 10 of the latest revision of the IEEE Standard 519 "Recommended Practices & Requirements for Harmonic Control in Electric Power Systems" at the point of metering connection.

703. Power Factor
Whenever the customer's utilization equipment is of such characteristics as to produce a low power factor, the Company reserves the right to require the customer to raise such power factor, at the customer's expense, or to pay additional charges as provided in

certain of the Company's rates on file with the Regulatory Commission of the state wherein the customer is located.

704. X-Ray Equipment
At the option of the Company, x-ray equipment may be separately metered and/or supplied from separate transformers.

705. Electric Welders
Electric welding apparatus shall require special arrangements with the Company to determine its ability to serve before installation is made. (Refer to Paragraph 703)

706. Electric Motors
706.1 Motors are normally designed to operate at their rated voltage, plus or minus 10%; thus a 220 volt motor should operate satisfactorily at 208 volts or 240 volts.

706.2 To assure adequate safety to personnel and equipment, the customer shall provide and maintain protective devices in each phase to protect all motors against overloading, short circuits, ground faults and low voltage, and to protect all three-phase motors against single-phasing and phase reversal.

706.3 Motors for use at 120 volts single-phase are limited to locked rotor currents of 25 amperes if started more than 4 times per hour, and 50 amperes if started less frequently.

Motors for use at 208 or 240 volts single-phase will generally be limited to 3 h.p. and a maximum of 4 starts per hour. The Company must be consulted for single-phase motors above 3 h.p. Compensating starting equipment may be required to limit the starting current and when required, shall be furnished by the customer. (Refer to paragraph 702)

706.4 The size of three-phase motors permitted will depend upon the effect starting the motor has upon the customer's system and the Company's other customers in the area. This effect will depend upon the magnitude of the starting current and the frequency of starting. (Refer to Paragraph 702)

When necessary, the customer will be required to reduce the amount of starting current to an acceptable level by installing suitable motor-starting equipment or by using motors designed for smaller starting currents.

706.5 When more than one motor can start simultaneously, the sum of the maximum starting currents of those motors starting simultaneously and also the sum of their horsepower rating shall be furnished to the Company to determine when reduced voltage starting may be required.

707. Flashing Display Signs

The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

708. Fluorescent and Gaseous Tube Lighting

High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

709. Electric Heat Equipment

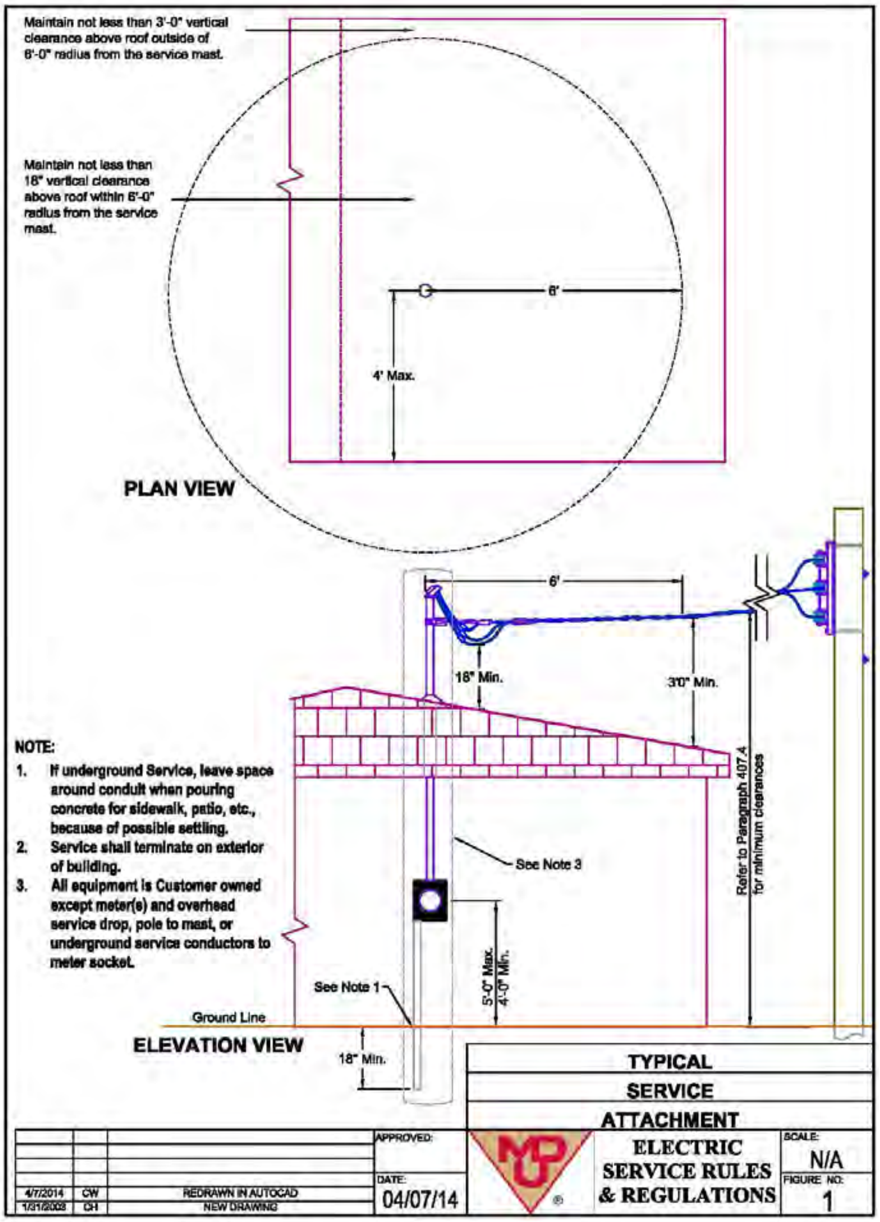
A customer planning to install resistance type heating, heat pump, electric furnace, electrode boiler, etc. shall consult with the Company, before purchasing the equipment, so that operational modes of this equipment are determined to be acceptable for connection to the Company's distribution system. It is important that consultation is obtained prior to installation of this equipment so the Company can provide adequate capacity to efficiently serve the customer's requirements.

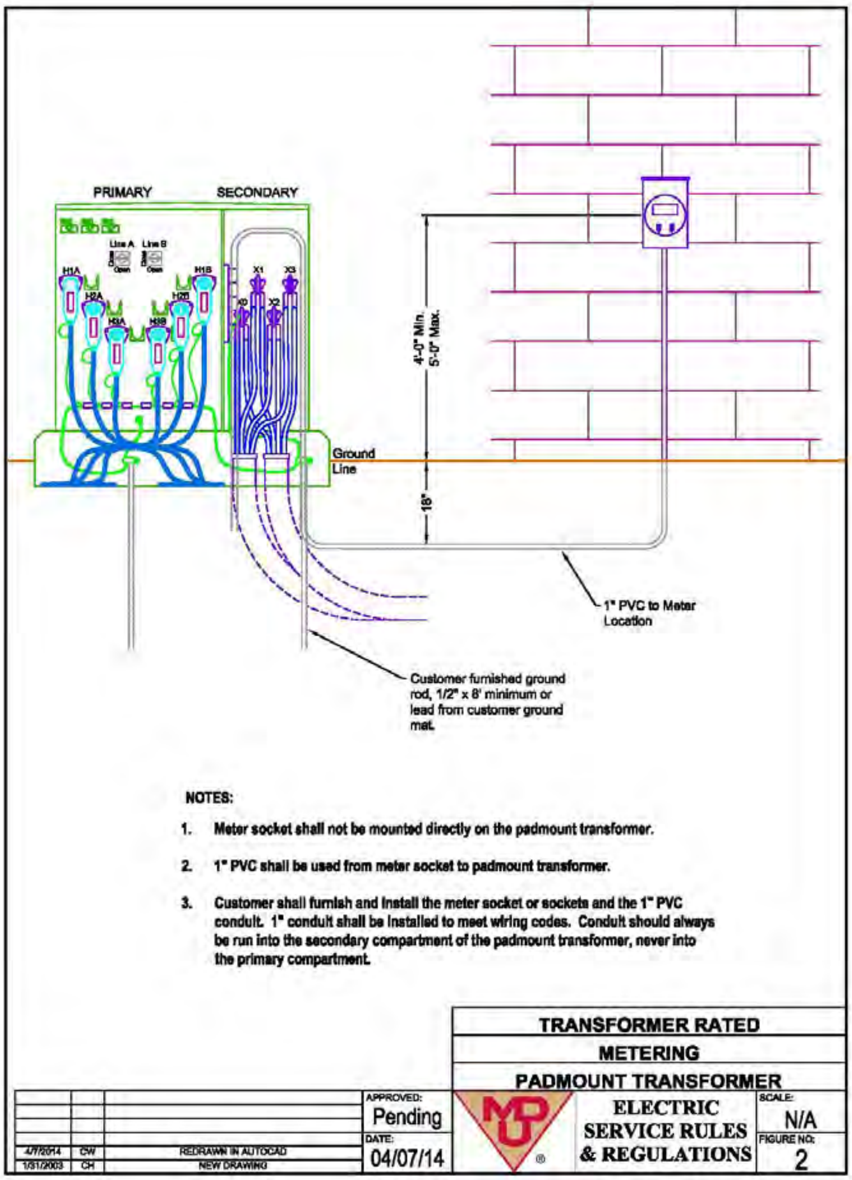
710. Computers and Electronic Equipment

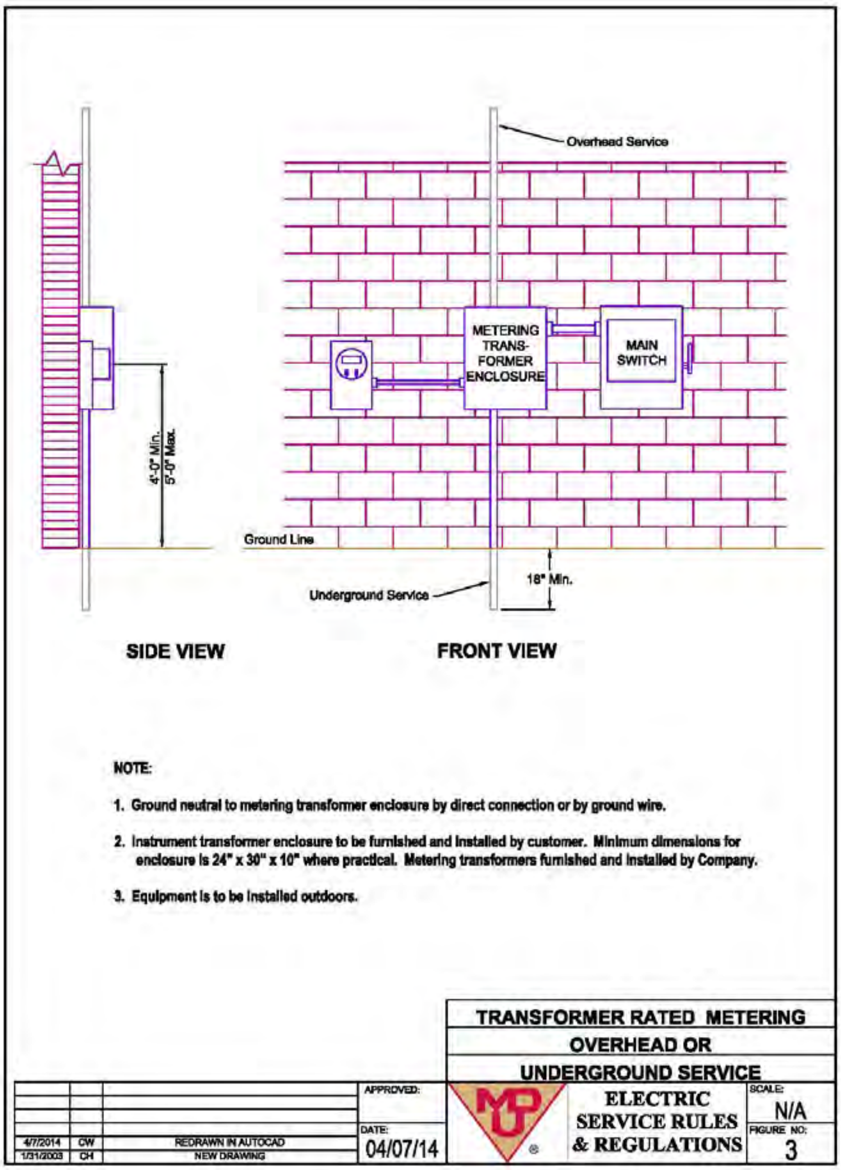
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters, surge suppressors, isolation transformers, and standby or uninterruptible power supplies. (Refer to Paragraph 104.2.)

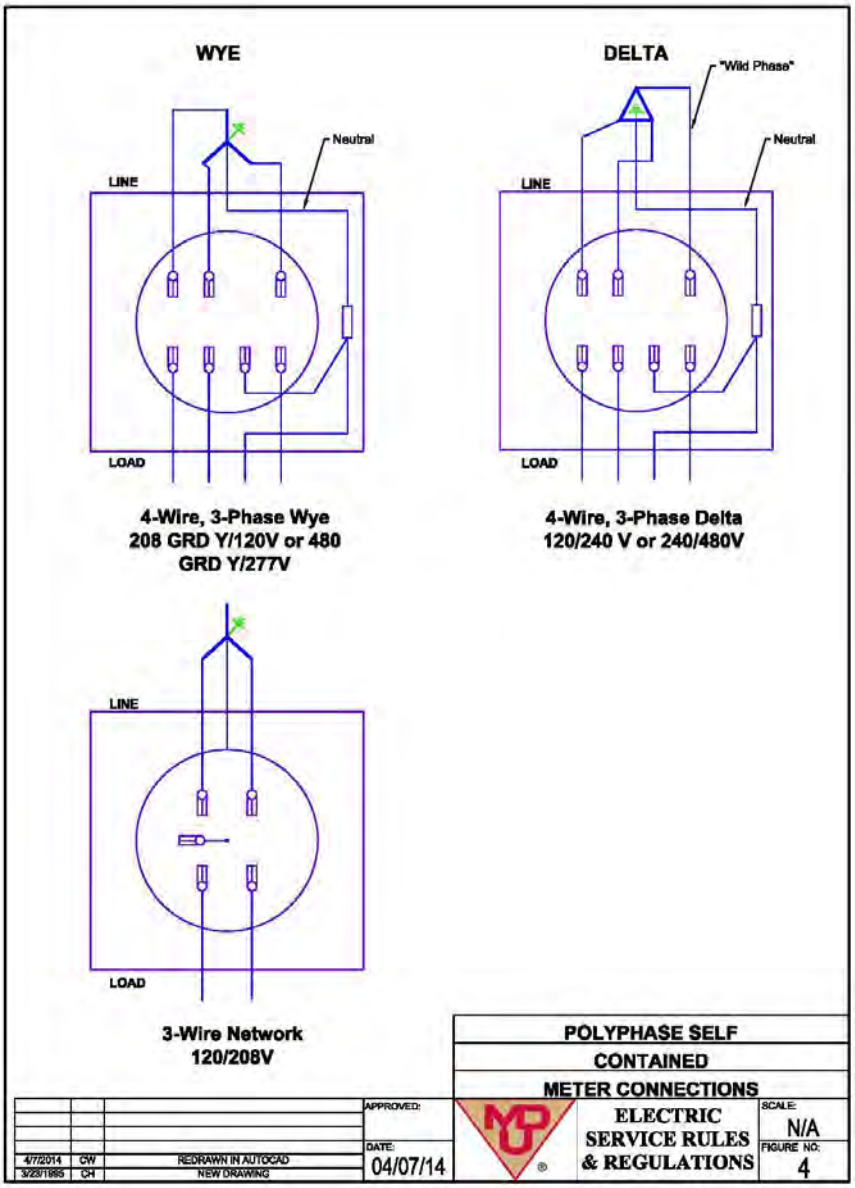
711. Carrier Equipment

The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system.

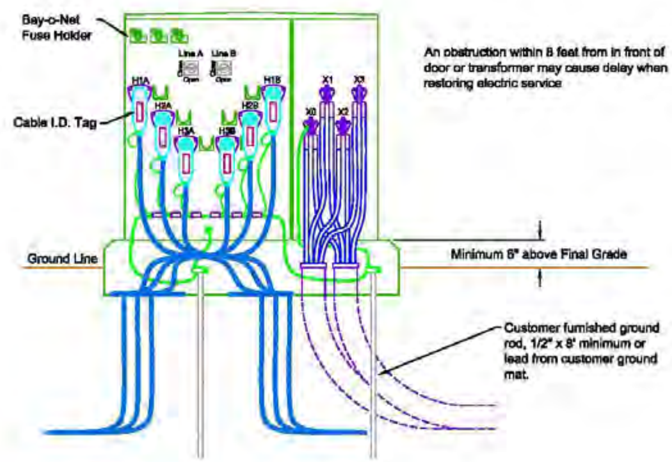

Maintain not less than 3'-0" vertical clearance above roof outside of 6'-0" radius from the service mast.
Maintain not less than 18" vertical clearance above roof within 6'-0" radius from the service mast.
6'
4' Max.
PLAN VIEW
6'
18" Min.
3'0" Min.
Refer to Paragraph 407.4 for minimum clearances
See Note 3
See Note 1
5'-0" Max.
4'-0" Min.
Ground Line
ELEVATION VIEW
18" Min.
NOTE:
1. If underground Service, leave space around conduit when pouring concrete for sidewalk, patio, etc., because of possible settling.
2. Service shall terminate on exterior of building.
3. All equipment is Customer owned except meter(s) and overhead service drop, pole to mast, or underground service conductors to meter socket.
TYPICAL
SERVICE
ATTACHMENT
ELECTRIC
SERVICE RULES
& REGULATIONS
SCALE:
N/A
FIGURE NO:
1
APPROVED:
DATE:
04/07/14
4/7/2014
CW
REDRAWN IN AUTOCAD
1/31/2003
CH
NEW DRAWING


PRIMARY
SECONDARY
Line A
Line B
H1A
H2A
H3A
H1B
H2B
H3B
X1
X3
X0
X2
4'-0" Min.
5'-0" Max.
Ground Line
18"
1" PVC to Meter Location
Customer furnished ground rod, 1/2" x 8' minimum or lead from customer ground mat.
NOTES:
1. Meter socket shall not be mounted directly on the padmount transformer.
2. 1" PVC shall be used from meter socket to padmount transformer.
3. Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.
TRANSFORMER RATED
METERING
PADMOUNT TRANSFORMER
APPROVED:
Pending
DATE:
04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
SCALE:
N/A
FIGURE NO:
2
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2003 CH NEW DRAWING


Overhead Service
METERING TRANS-FORMER ENCLOSURE
MAIN SWITCH
4'-0" Min.
5'-0" Max.
Ground Line
18" Min.
Underground Service
SIDE VIEW
FRONT VIEW
NOTE:
1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3. Equipment is to be installed outdoors.
TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE
ELECTRIC SERVICE RULES & REGULATIONS
SCALE: N/A
FIGURE NO: 3
APPROVED:
DATE: 04/07/14
4/7/2014 CW REDRAWN IN AUTOCAD
1/31/2003 CH NEW DRAWING



WYE
DELTA
"Wild Phase"
Neutral
LINE
LOAD
4-Wire, 3-Phase Wye
208 GRD Y/120V or 480 GRD Y/277V
4-Wire, 3-Phase Delta
120/240 V or 240/480V
3-Wire Network
120/208V
POLYPHASE SELF CONTAINED METER CONNECTIONS
ELECTRIC SERVICE RULES & REGULATIONS
APPROVED:
DATE:
04/07/14
SCALE:
N/A
FIGURE NO:
4
4/7/2014 CW REDRAWN IN AUTOCAD
3/23/1995 CH NEW DRAWING



NOTES:

1. Consult with Company for actual equipment pad dimensions.
2. Transformer pad, service cable, conduit and ground rod or mat for service cable grounding are furnished by Customer.
3. Allow sufficient slack in service entrance conductor to allow for proper connection to equipment terminals.
4. Service connectors to be furnished by Company.
5. Connection to Company's equipment terminals to be made by Company.
6. When more than four condutors are installed for each phase, consult Company for transition cabinet requirements.

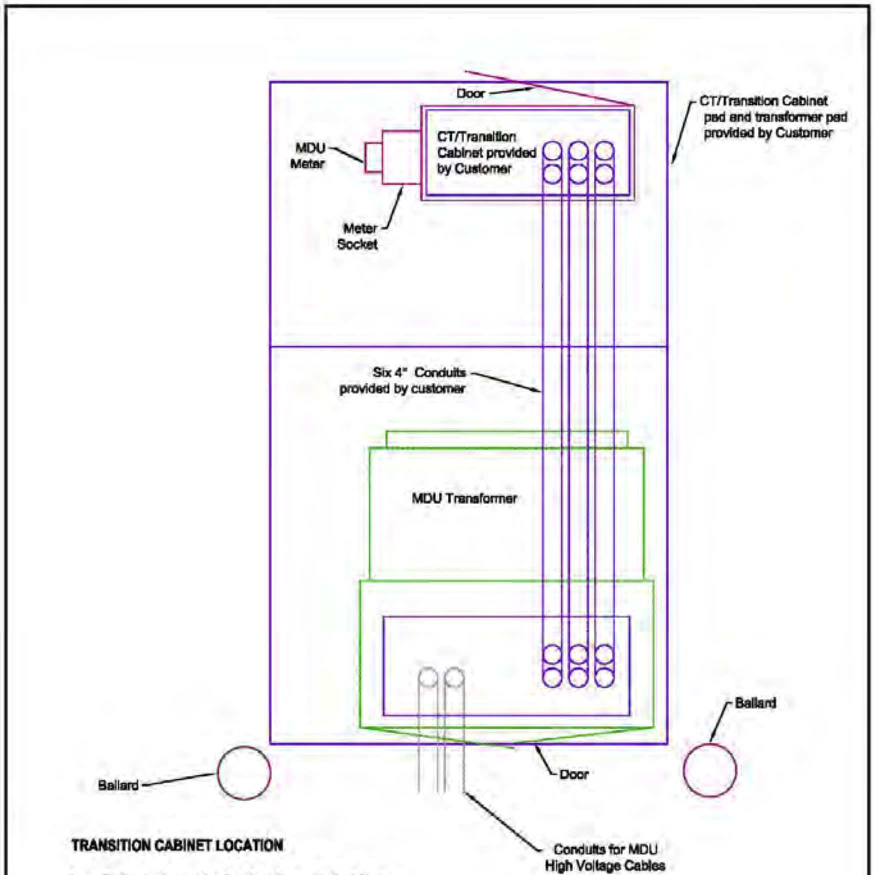
TRANSFORMER LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

TYPICAL PADMOUNT EQUIPMENT INSTALLATION

4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED: Pending
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

ELECTRIC SERVICE RULES & REGULATIONS
SCALE: N/A
FIGURE NO: 5



TRANSITION CABINET LOCATION

1. Entire pad must be five feet from any building.
2. All oil-filled padmounted transformers must be installed so any flow of oil resulting from a failure of the transformer will flow away from any structure.
3. A transformer should be located away from traffic areas or protected with ballards such as concrete filled pipes or steel bumper posts, provided by the customer.
4. When locating pad, consider overhead clearance for possible transformer replacement.
5. Compact soil to avoid tilting and settling. Columns required except on undisturbed soil.

4/7/2014	CW	NEW DRAWING	APPROVED: Pending	DATE: 04/07/14

TYPICAL TRANSITION CABINET INSTALLATION

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A
FIGURE NO: 6

The policy of Montana-Dakota Utilities Co. for electric extensions to provide service to customers located within its service territory is as follows:

1. A permanent extension may be constructed without a contribution if the estimated project construction cost is equal to or less than ~~two~~3.8 times the estimated annual revenue excluding fuel and purchased power (~~2~~3.8 to 1 ratio).

2. If the estimated project construction cost is greater than ~~two~~3.8 times the estimated annual revenue excluding fuel and purchased power, the extension will be made only with a contribution, which may be refundable.

   a. Contribution -

      1) When a contribution is required of any customer, with the exception of those customers defined in 2) below, the formula for determining the amount of the initial contribution shall be the estimated construction cost less ~~two~~3.8 times the estimated annual revenues excluding fuel and purchased power.

      2) The initial contribution for developers of subdivisions shall be the estimated construction cost.

      3) Payment of the initial contribution amount shall be made prior to construction.

      4) Upon completion of construction, the contribution amount shall be adjusted to reflect actual construction costs and an additional charge or refund levied accordingly.

      5) Company may waive all contributions if it determines that the initial contribution will be soon refunded because of additional customer connections.

b. Refund -
   1) If within a five-year period from the date initial service is established, one or more additional customers are added to the above referred to extension, Company shall recompute the contribution required by combining the estimated proposed construction cost for the new customer(s) with the construction cost to those customers already taking service. If, by so combining the construction costs, the contribution of those customers already taking service would be less, Company shall make a proportionate refund, without interest, to those customers taking service prior to commencement of service to said additional customer(s).

   2) Refunds for developers of subdivisions shall be made for each lot connected based on the following calculation: Total refundable contribution divided by the number of lots that can be served from the extension equals refund per lot. In addition, the total revenue excluding fuel and purchased power of the subdivision will be reviewed annually to determine if adequate revenues are being generated so that the contribution formula would indicate a zero contribution. When this revenue level is reached, a refund will be made to the developer equal to the remaining contribution amount still held by the Company.

   3) No refund shall be made by Company to customer(s) or developer after a five-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

   4) No interest will be paid by Company to customer(s) on any amount customer(s) has paid to Company as a contribution in aid of construction.

3. Project construction cost shall include all cost of the electric extension and overhead cost less the cost of customers' transformer(s), service line, and meter. The service line is considered to be the low voltage conductors between the Company owned transformer or secondary system and the customer owned service entrance equipment.

4. Electric extension refers to any facilities which must be constructed to connect a new customer to the utility system or the addition of capacity to existing facilities.

5. Company will deliver electricity to customer at the rate approved by the North Dakota Public Service Commission.

6. Where a contribution in aid of construction is required to provide service, such extension is subject to prior execution by customer and Company of Company's standard agreement for extensions.

7. Where abnormal conditions exist, causing extraordinary costs on any part of the extension (e.g., railroad or river crossing, land clearing, special permits, etc.), a charge may be made equal to the additional cost incurred by reason of the abnormal conditions.

8. This rule shall not be construed as prohibiting the Company from making a contract with a customer in a different manner, if the contract provides a more favorable method of extension to the customer. Such determination to be made on the basis of specific extension characteristics.

9. Temporary loads, such as gravel pit operations, carnivals, etc., shall follow the Company rules for temporary services.

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

A. NEW METERS

A sampling of 5% will be tested at full load and at light load. If any meter is found to be off more than ±1%, the entire lot will be tested or rejected.

B. RESIDENTIAL WATTHOUR METERS IN SERVICE

1. A random selection of meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979, 1980 to 1989, etc., will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 96% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 96% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of four years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

C. COMMERCIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 98% of the meters shall be not more than plus or minus 2% in error, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 98% of the tested meters in a given vintage class fail to meet the requirements of ±2% error limit, the entire vintage class will be tested and adjusted or, if more economic, replaced within a period of two years. In the event the meter type failing the ±2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

D. INDUSTRIAL WATTHOUR METERS

1. A random selection of electro-mechanical meters from each vintage class - 1950 to 1959, 1960 to 1969, 1970 to 1979 and meters manufactured since 1980, will be tested annually at full load and light load. A separate selection of solid state meters from each decade - 1990's, 2000's, etc. will be tested annually at full load and light load. The sample size will depend on lot size and will be calculated per Inspection Level V in Military Standards 414 of the Department of Defense.

2. Full load readings will be given a weighting of 4 and light load readings a weighting of 1 to determine the weighted average values of meter accuracies.

3. The criteria for acceptance shall be: at least 99% of the meters shall be not more than ±2% in error at both light load and full load, as determined by the Variability Unknown, Standard Deviation Method described in Military Standards 414 of the Department of Defense.

4. Whenever it is found that less than 99% of the tested meters fail to meet these requirements, the entire vintage class will be tested and adjusted or, if more economic, replaced within two years. In the event the meter type failing the $\pm$2% error limit may be identified, that meter type, regardless of vintage class, will be tested and adjusted or replaced within a period of four years rather than the entire vintage class.

General Rules for Generation:

1. The interconnection between the utility and the qualifying facility will be limited to the service voltage and phases available at the qualifying facility. If different voltages or phases are required, the necessary changes will be provided by the qualifying facility.

2. The power factor and frequency of the qualifying facility shall be such as to not adversely affect the utility system. If corrective devices are required, they will be provided by the qualifying facility.

3. Fault protection equipment shall be provided by the qualifying facility. The utility and qualifying facility shall coordinate protective devices in order to limit damage to each system.

4. The qualifying facility's interconnection shall meet the requirements of local, state and federal codes.

5. The owner of the qualifying facility shall submit equipment specifications as requested by the utility prior to owner's installation of such equipment to assure compatibility and coordination with the utility system.

6. The owner of a qualifying facility will be requested to curtail, interrupt or reduce deliveries of electric energy, in order that the utility may construct, install, maintain, repair, replace, remove or inspect any of its equipment or any part of its system, or if it determines that curtailment, interruption or reduction of delivery is necessary because of safety, emergencies, forced outages or operating conditions on its system. Except in case of emergency, in order to minimize operating problems, the utility and qualifying facility shall give the other reasonable prior notice of any curtailment, interruption or reduction of delivery and its probable duration.

7. The Company reserves the right for periodic inspection of safety devices which are part of the interconnection. This does not affect the responsibility of the qualifying facility to assure the operating safety of the equipment on its side of the interconnection point.

8. The Company reserves the right to disconnect any facility that has interconnected without utility authorization.

9. The Company has the right to disconnect and lock-out a qualifying facility's generating equipment with due notice whenever it has been determined that harmonics are being produced or other factors are present which would interfere with communications or otherwise cause degradation of service to other customers. If, in the judgment of the utility, an unsafe condition is created on the utility system by the operation of the qualifying facility the utility shall have the right to disconnect the facility until the cause of such condition is eliminated.

10. In the event of a utility system outage or interruption of service, a qualifying facility's generator shall be capable of automatically disconnecting itself to prevent the utility's line from being energized. Also, a qualifying facility's system shall not be capable of energizing the utility's line when that line is de-energized.

11. A manually operated generator disconnect switch, provided by the owner of a qualifying facility, shall be accessible to utility personnel at all times. Such a switch would be used, whether or not the owner is present to remove the qualifying facility's generator from the line in an emergency situation as determined by utility system conditions.

12. All necessary rights-of-way and easements to install, operate, maintain, replace and remove utility facilities, including adequate access rights are to be furnished by the owner of the qualifying facility on owner's property.

13. The metering shall be adequate to measure energy, or energy and capacity, from the qualifying facility to the utility, from the utility to the qualifying facility, and, if necessary, adequate to determine the time at which energy is transferred from one party to another.

14. If the qualifying facility is located at a site outside of Company service territory and energy is delivered to Company through facilities owned by another utility, energy payments will be adjusted reflecting losses occurring between point of metering and point of delivery.

15. In the event the qualifying facility desires wheeling by the Company of its output, arrangements will be made subject to negotiation.

16. A Metering Charge will be assessed the qualifying facility for installation by the Company of additional metering equipment plus operation and maintenance costs.

17. An Interconnection Charge will be assessed for any additional facilities (exclusive of the items included in Metering Charge) or changes in existing facilities to permit interconnection with the Company. Payment shall be a one-time payment.

18. The owner of a qualifying facility will indemnify and save the utility harmless from all loss on account of injury, death or damage to property caused by the qualifying facility unless the injury, death or damage is the direct result of the negligence of the utility.

19. Qualifying facilities shall be required to execute a contract that specifies a one or five-year minimum term depending upon applicable rate schedule and describes the responsibilities, liabilities, ownership of equipment, and location.

20. The owner of a qualifying facility shall obtain and maintain general liability insurance in an amount established by negotiation between the owner of a qualifying facility and the Company.

21. Qualifying facilities with generating capacity greater than 1000 Kw, or operating as a base loaded unit regardless of size, will require individual negotiation.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case No. PU-22-___

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. as well as 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 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 1.165 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 electric operations in the state of North Dakota. I will also provide an overview of the Company's request for an electric rate increase and discuss the policies and reasons underlying the major aspects of the request. Finally, I will address the need for an interim increase and introduce the other Company witnesses that will present testimony and exhibits in further support of the Company's request.

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

A. North Dakota is a part of Montana-Dakota’s interconnected electric system, which consists of generation, transmission, distribution, and general plant facilities serving approximately 93,500 customers in 119 communities in North Dakota. The Company’s North Dakota electric service area is divided into two operating regions with regional offices located in Bismarck and Dickinson. In addition, there are several district offices located in communities throughout the state. As of December 31, 2021, the Company had 542 full and part-time employees who live and work throughout the Company’s North Dakota electric and gas service area.

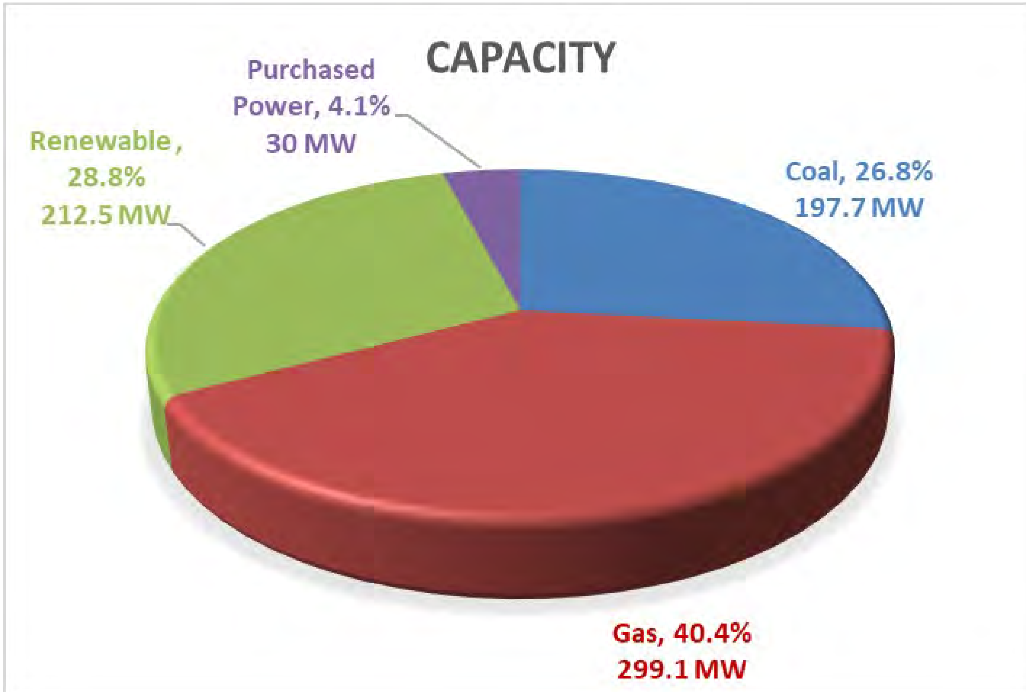
Montana-Dakota’s customers have toll-free access to the Customer Experience Team and the Credit Center to place routine utility service requests and inquiries from 7:30 am to 6:30 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A scheduling center, part of the Customer Experience 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 describe Montana-Dakota’s interconnected electric system?

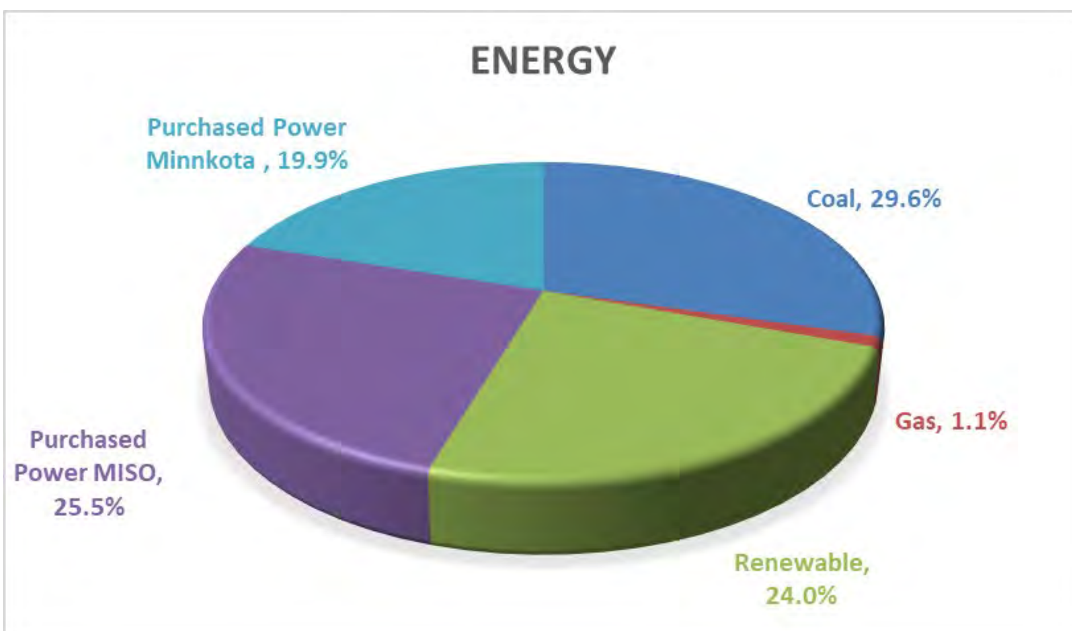
A. Through its interconnected electric system, Montana-Dakota serves approximately 127,000 retail customers in portions of North Dakota, Montana, and South Dakota. Montana-Dakota's current portfolio of generation assets is comprised of baseload coal-fired generation, natural gas-fired peaking generation, wind generation, portable diesel units, and a waste heat generating unit. Capacity and energy are also provided through a Power Purchase Agreement. Montana-Dakota plans to maintain and operate its current fleet of generation resources which provides the best cost power supply for our customers. The Company's projected 2023 capacity mix is as shown below and is comprised of:

Facility	Nameplate Capacity (MW)
Coal	
Big Stone	94.1
Coyote	103.6
Total	197.7
Gas	
Miles City	23.2
Glendive Unit I and II	75.5
Heskett Unit III	89.0
Heskett Unit IV	88.0
Lewis and Clark Unit II - RICE	18.7
Portables	3.7
Total	298.1
Renewable	
Diamond Willow	30.0
Ormat	7.5
Cedar Hills	19.5
Thunder Spirit	155.5
Total	212.5
Purchased Power	
Minnkota	30.0
Grand Total 1/	738.3

1/ Additionally the Company has a Demand-Side Management program that can reduce demand by 13.6 MW for Interruptible customers and 25.0 MW for Commercial Customers.



Customers' projected 2023 energy requirements are provided by the following resources as shown below.



Q. How are the costs associated with the ice storm that affected North Dakota on the weekend of April 23, 2022 handled in this case?

A. The storm caused widespread outages and unprecedented damage to the Company's transmission and distribution system. Due to the outstanding efforts of employees, all Montana-Dakota customers were re-energized by April 30, 2022. Because the Company is currently evaluating the current and future costs related to this event, there are no associated costs included in this case.

There are certain capital improvement projects included in the planned additions for 2022 and 2023 that were in the storm affected area. As a result, certain upgrades were necessary to complete the restoration; however, additional work is likely necessary to achieve the desired transmission standards.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for an electric rate increase?

A. Montana-Dakota is requesting an increase in its electric rates at this time because our current rates do not reflect the cost of providing electric service to the Company's North Dakota customers.

Q. When was the Company's last general rate case?

A. The Company's last rate case was Case No. PU-16-666. The resulting rate increase was $7.5 million or a 3.7 percent overall increase. Final rates in that case became effective on August 7, 2017. On March 9, 2018, Montana-Dakota filed Case No. PU-18-89 which represented revised electric rates in response to the federal 2017 Tax Cuts and Jobs Act. This resulted in a revenue reduction in base rates of $8,843,826 effective November 1, 2018.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting $25,365,558, which represents a 12.3 percent increase, based on a projected 2023 test year. Montana-Dakota currently has four riders: the Generation Resource Recovery Rider (Generation Rider), the Renewable Resource Cost Adjustment (Renewable Rider), the Transmission Cost Adjustment (Transmission Rider), and the Environmental Cost Recovery Rider (Environmental Rider) (with no current recovery). The 12.3 percent increase includes the effect on the base electric rates and the Generation Rider. No changes to the Renewable and Transmission Rider are included in this request.

More specifically, Montana-Dakota is proposing to move or expand the cost recovery from certain riders and base rates as follows:

- Move the retired investment and related expenses of Lewis & Clark Unit I and Heskett Unit I and II from base rates to the Generation Rider.

- Move the production investment and related expenses of Lewis & Clark Unit II (RICE) currently recovered through the Generation Rider to base retail rates.
- Recover the production investment and related expenses of Heskett Unit IV in base retail rates.

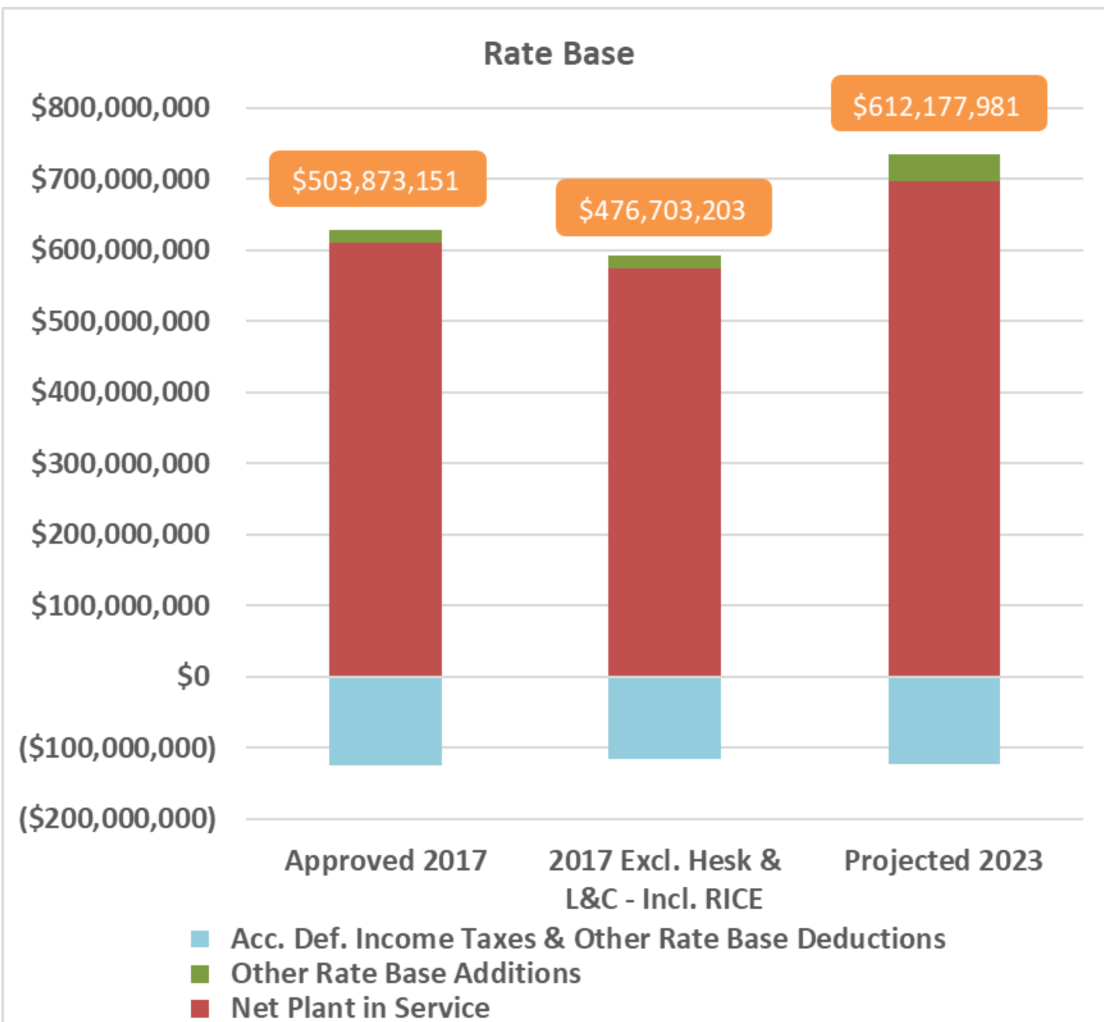
Q. How would this increase effect the Company's residential customers?

A. The typical non-space heating residential customer using an average of 800 kWh per month would see a monthly increase of approximately $14.94 or 16.6 percent. This equates to an annual increase of approximately $179. This filing also includes an increase in the daily basic service charge from 46 cents per day ($13.99 monthly) to 67 cents per day ($20.38 monthly).

Since the Company last filed a rate case in 2016 in Case No. PU–16-666, this filing represents an average annual increase of 2.5 percent per year, inclusive of riders.

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

A. As noted earlier, the last rate increase was implemented August 7, 2017 based on a projected 2017 revenue requirement. It was then adjusted to reflect the Tax Cuts and Jobs Act of 2017 on November 1, 2018. The major reason for this request is driven by the investments made since the last rate case, including the Heskett IV gas turbine. This additional investment results in an increase in the associated depreciation expense and property tax. As depicted in the graph below, the Company's net adjusted rate base has grown approximately $135.5 million or 28.4 percent since the 2017 rate base when adjusted to exclude Lewis & Clark Unit I and Hesket Unit I & II and to include the Lewis & Clark RICE Unit. This adjustment was performed to more accurately compare the rate base to the Projected 2023 which also excludes Lewis & Clark Unit I and Hesket Unit I & II and includes the Lewis & Clark RICE Unit.



Changes in O&M expenses represent another factor for the increase at this time. The closure of Lewis & Clark Unit I and Heskett Unit I & II coal units has resulted in significant savings. In addition, lower pension and post retirement costs have resulted in lower overall benefit costs. However, those savings have been offset by annual increases in labor since 2017, significant increases in software maintenance expenses and insurance expenses, as well as more recent inflationary increases. As shown in the table below, the Company's total O&M costs are expected to remain in line with those approved in the Company's last electric rate case.

	2017	Heskett & L&C Adj. 2017	2023	Adj. 2017 vs. 2023 Variance	% Variance
F&PP	$53,528,720	$53,528,720	$46,856,802	($6,671,918)	-12%
Labor	23,812,846	18,450,012	23,925,931	5,475,919	30%
Benefits	5,127,898	4,066,421	3,979,334	(87,087)	-2%
Coyote/Big Stone	7,322,372	7,322,372	7,901,511	579,139	8%
Insurance	1,738,625	1,738,625	2,844,554	1,105,929	64%
Software Mtnce	1,093,503	1,093,503	2,326,137	1,232,634	113%
Other O&M	16,278,879	12,032,465	13,744,897	1,712,432	14%
Total O&M	$108,902,843	$98,232,118	$101,579,166	$3,347,048	3%
Excl. F&PP	$55,374,123	$44,703,398	$54,722,364	$10,018,966	22%

Finally, the fuel and purchased power costs requested in this filing do reflect the savings associated with the closures of the Heskett and Lewis & Clark coal units and other changes since the last rate case. Customers have already been receiving the benefit of those savings as these have been passed on to customers through the monthly fuel and purchased power filings (Fuel Clause Adjustment) that reflect the actual costs incurred.

Q. How have the Company's labor expenses changed since the last case?

A. Since 2017, Montana-Dakota's labor expenses have been flat when compared to 2017. However, when comparing the Adjusted 2017 (which is exclusive of those costs associated with Lewis & Clark Unit I and Heskett Unit I & II), to the Projected 2023 expense, the Company realized a 4.4 percent increase per year, including additional positions.

Q. Have you performed a depreciation study for inclusion in this request?

A. Yes. A depreciation study for Montana-Dakota's electric plant in service was performed by Mr. Larry Kennedy of Concentric Advisors, ULC. Mr. Kennedy has provided testimony on behalf of the Company and is recommending a composite depreciation rate of 2.95 percent based on plant in service as of December 31, 2020 as compared to the 2.54 percent composite rate previously approved by this commission. The impact of the depreciation study results on the North Dakota electric jurisdiction is an increase of approximately $4.6 million in the revenue requirement.

Q. What other adjustments are contributing to the need for an increase in distribution rates?

A. In addition to the increase in rate base and the associated operating expenses including the updated depreciation rates, the

Company is requesting the inclusion of the provision for pension and post-retirement benefits, net of the associated deferred taxes, to be added to rate base.

Q. Why has the Company proposed to include the pension and post retirement regulatory assets in rate base at this time?

A. From 2009 through 2021, the Company made approximately $80 million in required cash contributions to the pension trust fund. The cash contributions made by the Company have significantly exceeded the pension expense, which is the amount included in the Company's revenue requirement as a component of O&M expenses and recovered through rates charged to customers. Similar to other investments, Montana-Dakota has a significant outlay in cash and its only opportunity to earn a return on the outlay of cash is by inclusion in the Company's rate base.

Montana-Dakota has taken a number of steps to minimize pension costs, including closing the pension plan to new participants and freezing the level of benefits accrued.

The post retirement prepaid asset, while much smaller in size, has similar characteristics as the prepaid pension asset and was included in the pro forma rate base as well.

Due in large part to the Company's recent contributions, pension and post retirement annual expenses have been reduced as they are recovered through the revenue requirement. In this case, pension and post retirement reflect a negative cost of $1.0 million which is a savings to customers and largely offsets the inclusion of the pension and post retirement net assets.

The inclusion of pension and post retirement is fully explained by Ms. Vesey.

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 $25.4 million increase in revenue is driven primarily by:

	Amount (in millions)
Increase in Rate Base	$13.8
Lower Sales	2.7
Higher O&M Expenses	10.0
Higher Depreciation	10.0
Property Tax	1.7
Other	1.0
Amortization of L&C and Heskett	7.8
Offset by:	
L&C and Heskett Savings	($21.6)
Net Increase	$25.4

The Heskett Unit IV addition is included in the Rate Base and represents approximately $5.6 million of the increase. The Depreciation Study effect of $4.6 million is also included in the depreciation increase.

Q. What actions has the Company taken to mitigate this increase?

A In Case No. PU-21-421, the Company calculated the revenue requirement associated with Lewis & Clark Unit I and Heskett Unit I and II currently included in the base rates to be $21,633,216. The Company is now proposing to reduce annual amortization to $7,832,580, which will extend the amortization period to 10 years. The $13.8 million reduction will extend the amortization period by approximately 6 years; however, it will also result in a significant decrease in customers' rates.

Q. What investments has the Company made since Case No. PU-16-666?

A. Montana-Dakota's invested approximately $245 million from 2018 through 2021. The investments have included:

- Production investments of approximately $91 million, which includes the $58 million expansion to the Thunder Spirit Wind facility which is currently being recovered in the Company's Renewable Rider.
- Transmission investments of approximately $73 million which include upgrades to aging substations and transmission lines, along with line projects to enhance reliability. The Company currently has approximately $51 million of these projects which are currently being recovered in the Transmission Rider.
- Distribution investments of approximately $54 million which include upgrading substations, replacing or upgrading transformers, replacing or upgrading distribution lines and reliability projects to maintain service to customers.

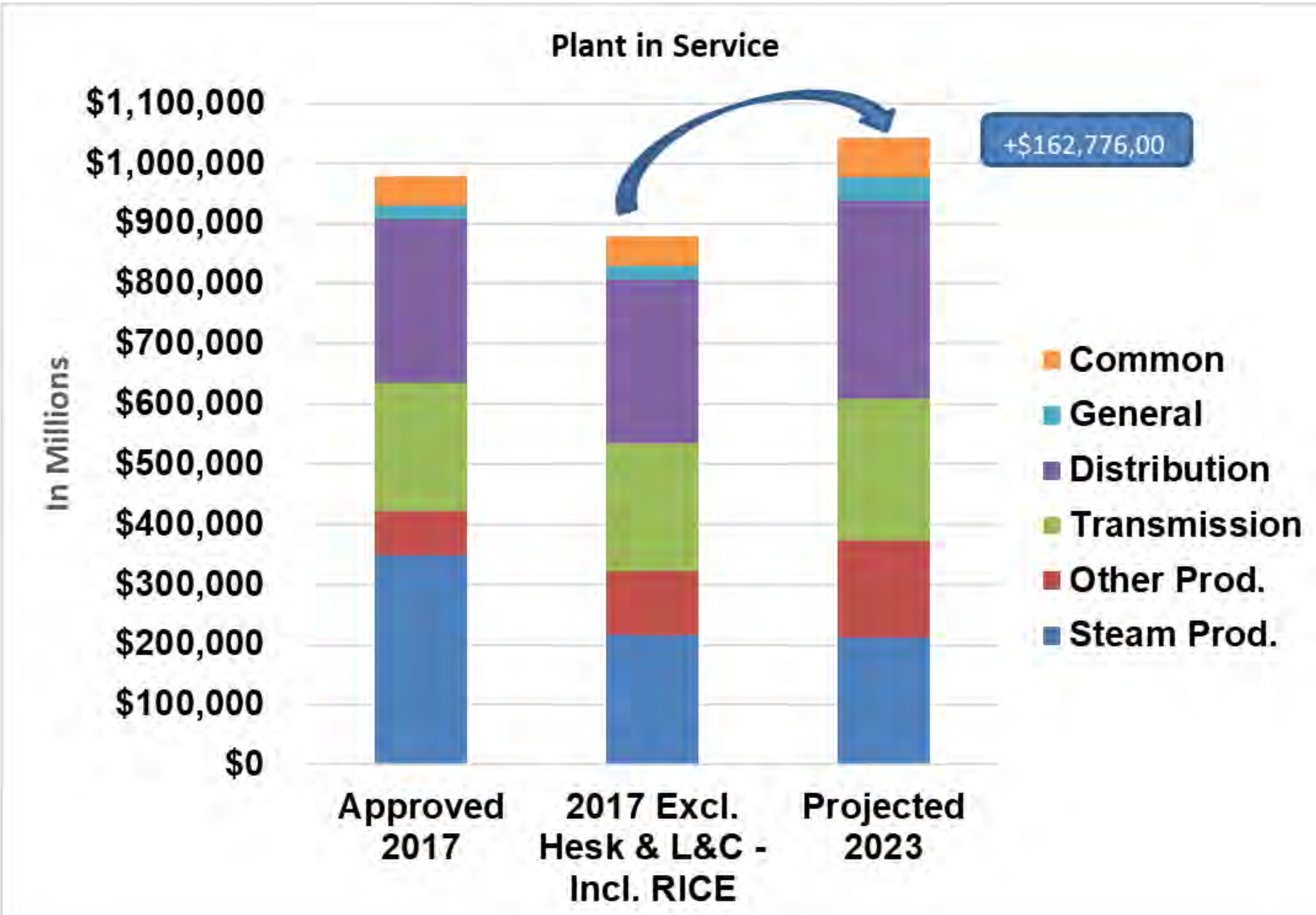
- General and Common investments of approximately $27 million, with larger investments coming from work equipment, software and hardware additions, building and shop upgrades.

Q. What incremental investments are included in this case as projected 2022 and 2023?

A. The Company has included incremental investments in 2022 and 2023 of approximately $142 million and are associated with the following investments:

- Production investments of approximately $58 million, the bulk of which are associated with the new generation addition of Heskett Unit IV, as discussed in greater detail by Mr. Geiger;
- Transmission investments of approximately $26 million including continued reliability upgrades necessary due to aging infrastructure, and is discussed in greater detail by Mr. Frank;
- Distribution investment of approximately $35 million including substation replacements and upgrades required to maintain reliable service, as discussed in greater detail by Mr. Frank;
- General and common plant additions of approximately $23 million primarily associated with work equipment, software systems, and the construction of structural buildings as discussed in greater detail by Mr. Martuscelli, Mr. Anderson, and Mr. Neigum.

The table below shows the investment in plant assigned and allocated to North Dakota electric operations from 2017 to projected 2023, excluding the Renewable and Transmission Riders.



Q. Montana-Dakota submitted its Integrated Resource Plan (IRP) on July 1, 2019. Attachment I of the IRP discussed the retirement of the Lewis & Clark and Heskett coal units and indicated that the Company's projections indicated a cost savings of $20.1 million for the integrated system. In light of this request for additional revenue, have customer seen those benefits?

A. Montana-Dakota's projections have come to fruition. Customers began seeing a reduction of Fuel & Purchase Power (F&PP) costs beginning in April 2021 with the closure of the Lewis & Clark station. Montana-Dakota entered into a Power Purchase Agreement (PPA) in 2021 that was favorable to the Company's projections. The PPA was sized to largely offset generation from the Lewis & Clark station and increased to match the closure of the Heskett stations. Therefore, the overall F&PP savings is greater than originally projected.

The projected changes in Operating Expenses and a reduction in the revenue requirement due to the removal of the plant investment from rate base continue to be in line with the original projections as well.

The last part of the cost savings was an offset related to the replacement generation resource, the Heskett IV gas combustion turbine, which is scheduled to be in operation in April 2023. The revenue requirement for that resource continues to be on track as the overall capital budget and anticipated operating costs are in line with those contemplated in the 2019 IRP.

Therefore, while the Company is requesting an increase in the overall revenue requirement at this time, if the 3 coal units had continued operating, rather than being retired, the requested increase would have been higher.

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

Rate Class	Overall Class Impact
Residential Service	17.3%
Small General Service	18.4%
General Service	7.8%
Municipal Lighting	7.3%
Municipal Pumping	13.8%
Outdoor Lighting Service	4.2%
Total	12.3%

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

A. Montana-Dakota is requesting an overall return of 7.513 percent, inclusive of a return on equity (ROE) of 10.5 percent. Ms. Bulkley's analysis indicates that a 10.5 percent ROE is fully justified and supported based on the results of her studies.

Q. Is Montana-Dakota 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. Montana-Dakota's overall rate of return on its investment was 5.942 percent as of December 31, 2021, resulting in a return on equity of 7.834 percent, below the authorized return of 9.65 percent. The amount of interim relief sought is $11,422,625 or 6.6 percent and consists of the Company's projected 2023 revenue requirement adjusted to reflect the return on equity of 9.65 percent authorized in Case No. PU-16-666 and the exclusion of items that were not a part of the last rate case. As noted above, Montana-Dakota is proposing to extend the amortization period of Lewis & Clark Unit I and Heskett Unit I & II by reducing the amortization to mitigate the overall increase. The Company proposes to similarly reduce the amortization period at the time interim rates are implemented. If the reduced amortization is not granted, the amount of interim relief sought would be higher.

The interim request will be described in more detail by Ms. Vesey. The proposed interim rates are described by Ms. 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 in this proceeding?

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

- Ms. Tammy J. Nygard, Controller for Montana-Dakota, will testify regarding the overall cost of capital, capital structure, and overall debt costs.
- Ms. Ann E. Bulkley, Principal of The Brattle Group, will testify regarding The appropriate cost of common equity for Montana-Dakota's North Dakota electric operations.
- Mr. Joseph E. Geiger, Director of Generation for Montana-Dakota, will testify regarding Heskett Unit IV and the Power Production capital expenditures.
- Mr. Robert Frank, Director of Electric Transmission Engineering, will testify regarding transmission and substation capital expenditures.
- Mr. Darcy J. Neigum, Director of System Operations and Planning for Montana-Dakota, will testify regarding the Company's electric load forecast and the two-way radio replacement project.
- Mr. Eric P. Martuscelli, Vice President of Field Operations for Montana-Dakota, will testify regarding the Field Operations capital expenditures and the Work and Asset Management System.
- Mr. Daryl Anderson, Director of Electric Distribution Services for Montana-Dakota, will testify regarding the Outage Management System and the transformer purchases and replacements.
- Mr. Larry E. Kennedy, Senior Vice President of Concentric Energy Advisors, Inc., will testify regarding the Company's depreciation study

of the plant in service as of December 31, 2020 that supports the proposed depreciation rates in this filing.

- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement, the interim revenue requirement, and the proposed changes in the generation rider necessary for North Dakota electric operations.
- Mr. Ron J. Amen, Managing Partner with Atrium Economics, LLC, will testify regarding the Company's embedded class cost of service study and the proposed rate design.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota, will testify regarding proposed tariff changes and the derivation of interim rates.

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

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

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case No. PU-22___

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. 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 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 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. 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 shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2021 and the projected capital structure for 2022 and 2023. Statement E includes the associated costs of short and long term debt and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.513 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 Bulkley.

As shown on page 1, the components of the 2023 projected overall annual rate of return, which are used by Ms. Tara Vesey to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.008%
Short Term Debt	0.170%
Common Equity	5.335%
Required Rate of Return	7.513%

Q. How does the Company finance its electric 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 significant capital expenditures for new plant investment throughout its service territory, including new generation sources for capacity and energy such as the Heskett IV natural gas turbine, the Diamond Willow wind repower, as well as transmission upgrades to enhance system reliability across the Company's integrated system. 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 targeting a 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 obtained $15.0 million of additional common equity in 2021. In addition, the Company expects to receive approximately $23.5 million of common equity during 2022 and $5.0 million of common equity in 2023 in order to achieve and maintain the targeted capital structure.

In December 2020, the Company had $50.0 million short-term debt outstanding which was repaid in March 2021. In March 2021, the

Company entered into a separate $50.0 million term loan agreement with a maturity date of March 7, 2022. The Company repaid this $50.0 million term loan in December 2021 utilizing the proceeds of recently issued long-term debt as noted below.

On September 15, 2021, the Company entered into a $125.0 million note purchase agreement with $75.0 million issuance September 15, 2021 and a delayed draw of $50.0 million on December 15, 2021. The $50.0 million delayed draw was used to pay off the $50.0 million short-term debt. The Company is not projecting to issue any new long-term debt in 2022 or 2023.

Q. Were there any adjustments made to the short or long-term debt in the rate of return calculation? If so, please explain.

A. As described above, the Company had $50.0 million of short-term debt at December 31, 2020. This short-term debt was repaid in March 2021. In March 2021, the Company entered into another short-term debt of $50.0 million which was repaid in December 2021 with long term debt. Therefore, since this $50.0 million short-term note outstanding at 12/31/2020 was converted to a long-term note in 2021, the $50.0 million was presented as a long-term note in the capital structure. The Company felt this was the most appropriate way to account for this $50.0 million to avoid including in both short-term debt and long-term debt at the end of the year.

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, 2021, and associated cost of debt, and it shows the projected long-term debt and associated costs for 2022 and 2023. Page 2 shows the cost and the long-term debt balance by issue at December 31, 2021. Page 3 shows the projected cost and the long-term debt balance by issue at December 31, 2022 and page 4 shows the projected cost and the long-term debt balance by issue at December 31, 2023. The average cost of long-term debt for 2023, as shown on page 1, is 4.503 percent. This compares to the currently authorized cost of long-term debt of 5.341 percent. This equates to a savings of approximately $2.3 million in the revenue requirement as calculated in this filing.

Q. How did you derive the projected cost of long-term debt for 2022 and 2023?

A. The projected cost of debt for 2022 and 2023 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 2021 and projected 2022 and 2023 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. This schedule presents the average common equity balance at December 31, 2021 and the projected balance for December 31, 2022 and December 31, 2023 reflecting the projected activity in the balance.

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 Company uses the same calculation for accounting purposes. The balance of the PCN Notes issuance expense became fully amortized during 2022, which corresponds to the initial maturity dates of the associated PCN Notes. There is no cost associated with these notes in 2023.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No.___(AEB-1)

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
CASE NO. PU-22___
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.

Q2. What is your position with The Brattle Group ("Brattle")?

A2. I am employed by The Brattle Group ("Brattle") as a Principal.

Q3. On whose behalf are you submitting this testimony?

A3. I am submitting Direct Testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated electric utility operations of Montana-Dakota Utilities Co. within North Dakota ("Montana-Dakota" or the "Company").

Q4. Please describe your background and professional experience in the energy and utility industries.

A4. 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 provided testimony regarding financial matters, including the cost of capital, before multiple regulatory agencies. 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. A summary of my professional and educational background is presented in Exhibit No. ___ (AEB-2), Schedule 1.

Q5. Have you testified before any regulatory authorities?

A5. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No. ___ (AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q6. What is the purpose of your Direct Testimony?

A6. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Montana-Dakota's return on equity ("ROE")[1] for its electric utility operations to be used for ratemaking purposes. I also address the appropriateness of the Company's proposed capital structure. My analyses and recommendations are supported by the data presented in Exhibit No. ___(AEB-2), Schedules 2 through 11, which were prepared by me or under my direction.

Q7. Please provide a brief overview of the analyses that led to your ROE recommendation.

A7. As discussed more in Section VI in developing my ROE recommendation, I applied the Constant Growth Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Risk Premium approach. My recommendation also takes into consideration: (1) the regulatory environment in which the Company operates; (2) the Company's customer concentration;

[1] Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity".

and (3) flotation costs. While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate where the Company's ROE falls within the range of analytical results. Finally, I consider the Company's proposed capital structure as compared to the capital structures of the proxy companies.

Q8. How is the remainder of your Direct Testimony organized?

A8. 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 on Montana-Dakota's cost of equity. Section V explains my selection of proxy group of electric utilities. Section VI describes my analyses and the analytical basis for the 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 discusses the capital structure of the Company as compared with the proxy group. Section IX presents my conclusions and recommendations for the market cost of equity.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q9. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A9. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[2, 3] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that the end result must lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q10. Please explain how you considered those factors.

A10. I have relied on several analytical approaches to estimate Montana-Dakota's cost of equity based on a proxy group of publicly traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results. My conclusion as to where within that range of results Montana-Dakota's ROE falls is based on Montana-Dakota's business and financial risk relative to the proxy group. While my proxy group is generally comparable to Montana-Dakota, Montana-Dakota faces higher risk than the group. In order for Montana-Dakota to compete for capital within the proxy companies, those additional risk factors should be acknowledged and reflected in Montana-Dakota's ROE.

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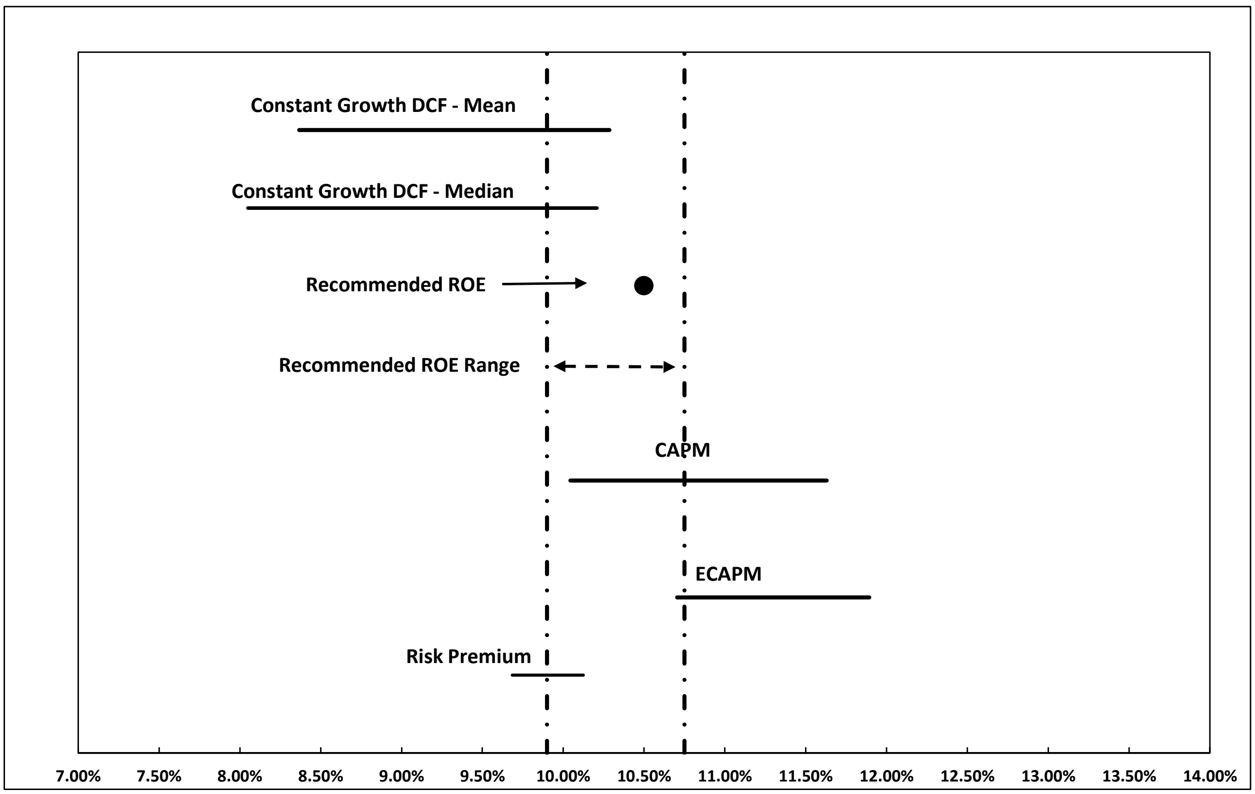
[2] U.S. Supreme Court, *Bluefield Water works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923).

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

Q11. Please summarize the ROE estimation models that you considered to establish the range of ROEs for Montana-Dakota.

A11. I considered the results of the Constant Growth DCF model, the Capital Asset Pricing Model ("CAPM"), the Empirical CAPM and the Bond Yield Plus Risk Premium methodology. Figure 1 summarizes the range of results established using each of these estimation methodologies.

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1, (and in Exhibit No.___(AEB-2), Schedule 2), the range of results produced by the ROE 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. As a result, my ROE recommendation considers the range of results of the Constant Growth DCF model, as well as the results of the CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses. My ROE recommendation also considers Montana-Dakota's company-specific risk factors and current and prospective capital market conditions.

Q12. What is your recommended ROE for Montana-Dakota?

A12. Considering the analytical results presented in Figure 1, as well as the level of regulatory, business, and financial risk faced by Montana-Dakota's electric operations in North Dakota relative to the proxy group, I believe a range from 9.90 to 10.75 percent is reasonable. Within that range, a return of 10.50 percent is reasonable. This recommendation reflects the range of results for the proxy group companies, the relative risk of Montana-Dakota's electric operations in North Dakota as compared to the proxy group, and current capital market conditions.

Q13. Please summarize your analysis of the appropriate ratemaking capital structure for the Company.

A13. Based on the analysis presented in Section VIII of my testimony, I conclude that Montana-Dakota's proposed 50.79 percent common equity ratio for the rate year ending December 31, 2022 and 50.81 percent common equity ratio for the rate year ending December 31, 2023 are reasonable. To determine if Montana-Dakota's requested capital structure was reasonable, I reviewed the capital structures of the utility subsidiaries of the proxy companies. As shown in Exhibit No.___(AEB-2), Schedule 11, the results of that analysis demonstrate that the average equity ratios for the utility operating companies of the proxy group range from 46.83 percent to 59.91 percent, with an average of 52.35 percent. Comparing the recommended equity ratio to the proxy group demonstrates that the Company's requested equity ratio is significantly below the average equity ratio for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering the negative effects from Tax Cuts and Jobs Act of 2017 ("TCJA") on coverage ratios and increased capital expenditures on the cash flows and credit metrics of regulated utilities.

III. REGULATORY GUIDELINES

Q14. Please describe the guiding principles to be used in establishing the cost of capital for a regulatory utility.

A14. 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) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[4]

Based on those recognized standards, the return authorized in this case should provide the Company with the opportunity to earn an ROE that is:

- Adequate to attract capital on reasonable terms, thereby enabling the Company to provide safe, reliable service;
- Sufficient to ensure the financial soundness of the Company's operations; and
- Commensurate with returns on investments in comparable risk enterprises.

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[4] *Supra 3 and 4.*

The allowed ROE should enable the Company to finance capital expenditures on reasonable terms and optimize its financial flexibility over the period during which rates are expected to remain in effect.

Q15. Is fixing a fair rate of return just about protecting the utility's interests?

A15. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties." Bluefield Waterworks & Imp. Co. vs. Pub. Serv. Commn. of W. Va., 262 US 679, 693, 43 S Ct 675, 679, 67 L Ed 1176 (1923). As the Court went on to explain in *Hope*, "[t]the rate-making process … involves balancing of the investor and consumer interests." Fed Power Commn. v. Hope Nat. Gas Co., 320 US 591, 603 (1944).

Q16. 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?

A16. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric utility service while maintaining its financial integrity. To the extent the Company has the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q17. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A17. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to 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 for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE that is not in line with authorized ROEs for other natural gas and electric utilities, on a risk adjusted basis, can inhibit the utility's ability to attract capital for investment in North Dakota.

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.

Q18. What are your conclusions regarding regulatory guidelines and capital market expectations?

A18. 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. Further, in light of the Company's market and regulatory risks as discussed below, it is important that Montana-Dakota be afforded the opportunity to maintain a financial profile that will enable it to access the capital markets at reasonable rates.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or the expectations of market risk, in the case of the CAPM. The results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the practitioner uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE to be determined for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE 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 are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A20. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: 1) changes in monetary policy, 2) currently high inflation continuing into 2022, 3) increasing interest rates, and 4) volatile market conditions. These factors affect the assumptions used in the ROE estimation models. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

Q21. What effect do current and prospective market conditions have on the cost of equity for Montana-Dakota?

A21. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation, the Federal Reserve's changes in monetary policy, and the dramatic shifts in market conditions resulting from political influences all contribute to an expectation of increased market risk and an increase in the cost of the investor-required return on equity. It is essential that these factors be considered in setting a forward-looking cost of equity. Inflation is currently at its highest level seen in approximately 40 years. Interest rates, which have increased from significantly from pandemic-related lows seen in 2020 are expected to continue to increase in direct response to the Federal Reserve's use of monetary policy. As discussed later herein, since there is a strong historical inverse correlation between interest rates and the share prices of utility stocks, it is reasonable to expect that investors' cost of equity is increasing. Because the cost of equity in this proceeding is being estimated for the 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, ROE estimates based in whole or in part on current market conditions will understate the ROE during the future period that the Company's rates will be in effect.

A. The Effect of Monetary Policy on Market Dynamics

Q22. Please summarize the monetary policy actions of the Federal Reserve in response to the economic effects of COVID-19.

A22. In response to the COVID-19 pandemic, the Federal Reserve:

- decreased the Federal Funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent;
- increased its holdings of both Treasury and mortgaged-back securities;
- started expansive programs to support credit to large employers – the Primary Market Corporate Credit Facility to provide liquidity for new issuances of corporate bonds; and the Secondary Market Corporate Credit Facility to provide liquidity for outstanding corporate debt issuances; and
- supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.

In addition, Congress also passed the Coronavirus Aid, Relief, and Economic Security ("CARES") Act in March 2020, the Consolidated Appropriations Act, 2021 in December 2020, and the American Rescue Plan Act in March 2021, which included $2.2. trillion, $900 billion, and $1.9 trillion, respectively, in fiscal stimulus aimed at also mitigating the economic effects of COVID-19. These expansive monetary and fiscal programs mitigated the economic effects of the COVID-19 pandemic and provided additional support as the economy recovers from the COVID-19 recession.

Q23. How did the accommodative monetary and fiscal policy affect the U.S. economy?

A23. The expansive monetary and fiscal policy programs resulted in a strong economic recovery in 2021 from the COVID-19 induced recessionary period in 2020. In fact, according to the Bureau of Economic Analysis, real GDP grew by 5.7 percent in 2021 driven primarily by a 7.9 percent increase in personal consumption expenditures.[5] Moreover, the unemployment rate decreased from a high of 14.7 percent in April 2020 to 3.9 percent as of December 2021.[6] Finally, as I will discuss in more detail below, the economic recovery has also included a substantial increase in inflation with the year-over-year ("YOY") change in the Consumer Price Index ("CPI") at 8.56 percent in March 2022. The strong economic recovery along with the increase in inflation has resulted in the Federal Reserve normalizing monetary policy and removing the accommodative policy programs that it used to mitigate the effect of COVID-19.

Q24. Is the Federal Reserve currently normalizing monetary policy?

A24. Yes. In response to the significant increase in inflation that will be discussed in more detail below, the Federal Reserve is currently pursuing an aggressive normalization of monetary policy. As of the May 4, 2022 meeting, the Federal Reserve:

- Completed its taper of Treasury bond and mortgage-backed securities purchases[7];
- Increased the target federal funds rate from 0.00 – 0.25 percent to 0.25 – 0.50 percent at the March 16, 2022 meeting[8] and then from 0.25 – 0.50 percent to 0.75 to 1.00 percent at the May 4, 2022 meeting[9];
- Forecasted a total of seven rate increases in 2022 and four rate increases in 2023 which resulted a median forecast of the federal funds rate of 1.9 percent and 2.8 percent, respectively[10];
- Will begin reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022.[11] The Federal Reserve will reduce the size of its balance sheet by

[5] Source: Bureau of Economic Analysis, News Release, February 24, 2022, at 8.
[6] Source: Bureau of Labor Statistics. https://data.bls.gov/timeseries/LNS14000000
[7] Source: Federal Reserve Bank of New York, https://www.newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.
[8] Source: Federal Reserve, Press Release, (Mar. 16, 2022).
[9] Source: Federal Reserve, Press Release, (May 4, 2022).
[10] Federal Reserve, Summary of Economic Projections, March 16, 2022, at 2.
[11] Source: Federal Reserve, Press Release, (May 4, 2022).

only reinvesting principal payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury Securities, the cap will be set at $30 billion per month for the first three months and $60 billion per month after the first three months while for mortgage-backed securities the cap will be set at $17.5 billion per month for the first three months and $35 billion per month after the first three months.[12]

Q25. What is the market response to the recent FOMC meetings?

A25. The market response is an expectation that interest rates will increase to address inflation. The CME Group calculates investors' views regarding the probability of the target federal funds rate range at upcoming Federal Reserve meetings based on federal funds rate futures contracts. Figure 2 below contains investors' expectations regarding the level of the federal funds rate at each of the next eleven meetings as of May 5, 2022. As shown in Figure 2, investors expect the Federal Reserve to increase the federal funds rate at a faster pace than what was indicated in the forecasts released at the Federal Reserve's March 16, 2022 meeting. For example, as shown in Figure 2, according to the CME Group, there is a 53.6 percent probability[13] that the target federal funds rate range is 3.00 percent to 3.25 percent as of December 2022 which is greater than the Federal Reserve's median forecast of 1.90 percent. In particular:

- Citigroup, Inc. is now projecting 50 basis point increases at the next four FOMC meetings followed by 25 basis point increases in October and December, reaching 3.50 to 3.75 percent.
- Bank of America Corp. is projecting a 25 basis point increase in May, followed by two 50 basis point increases, and then a 25 basis point increase at each subsequent meeting through May 2023, reaching a range of 3.00 to 3.25 percent.

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[12] Source: Federal Reserve, Plans for Reducing the Size of the Federal Reserve's Balance Sheet, Press Release, (May 4, 2022).

[13] The probability of a rate hike is calculated by adding the probabilities of all target rate levels above the current target rate.

- Goldman Sachs Group Inc. is projecting 50 basis point increases at the May and June FOMC meetings with a 25 basis point increase at the four remaining meetings in 2022.[14]Moody's recently noted that the financial markets are close to fully pricing in three 50-basis point rate increases this year.[15]

Thus, investors expect that the Federal Reserve will pursue more aggressive monetary policy than indicated at the March 16 meeting to combat persistent high levels of inflation.

Figure 2: Investor Expectation of Future Federal Funds Rate Increases[16]

MEETING PROBABILITIES															
MEETING DATE	125-150	150-175	175-200	200-225	225-250	250-275	275-300	300-325	325-350	350-375	375-400	400-425	425-450	450-475	475-500
6/15/2022	12.9%	87.1%	0.0%	0.0%											
7/27/2022	0.0%	0.0%	12.8%	86.9%	0.3%	0.0%	0.0%	0.0%	0.0%						
9/21/2022	0.0%	0.0%	0.0%	6.8%	52.1%	41.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
11/2/2022	0.0%	0.0%	0.0%	0.0%	5.4%	43.0%	43.2%	8.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12/14/2022	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%	41.2%	43.2%	10.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%
2/1/2023	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	17.4%	41.9%	31.9%	6.8%	0.3%	0.0%	0.0%	0.0%	0.0%
3/15/2023	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	8.8%	28.4%	37.4%	20.6%	3.8%	0.2%	0.0%	0.0%
5/3/2023	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.5%	10.5%	29.2%	36.0%	19.2%	3.5%	0.1%	0.0%	0.0%
6/14/2023	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	6.4%	20.7%	32.9%	26.8%	10.6%	1.7%	0.1%
7/26/2023	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	5.5%	18.4%	30.9%	27.8%	13.2%	3.1%	0.3%

Q26. Has the Federal Reserve provided support for investors' expectations regarding the federal funds rate since the Federal Reserve's projections were released at the March 2022 meeting?

A26. Yes. Specifically, at the May 4, 2022 meeting, the Federal Reserve increased the federal funds rate 50 basis points from 0.25 – 0.50 percent to 0.75 to 1.00 percent and at his press

14 Lanman, Scott, "Wall Street Lifts Fed Forecasts; Citi See Four Half-Point Hikes," Bloomberg, March 25, 2022.

15 Moody's Analytics, Weekly Market Outlook, "Fed Girds for Stagflation", April 14, 2022.

16 CME Group; FedWatch tool as of May 5, 2022.

conference, Federal Reserve Chairman Powell noted that additional 50 basis point increases may be needed at the next couple of meetings:

> "[w]e are on a path to move our policy rate expeditiously to more normal levels. Assuming that economic and financial conditions evolve in line with expectations, there is a broad sense on the Committee that additional 50 basis point increases should be on the table at the next couple of meetings. We will make our decisions meeting by meeting, as we learn from incoming data and the evolving outlook for the economy. And we will continue to communicate our thinking as clearly as possible. Our overarching focus is using our tools to bring inflation back down to our 2 percent goal."[17]

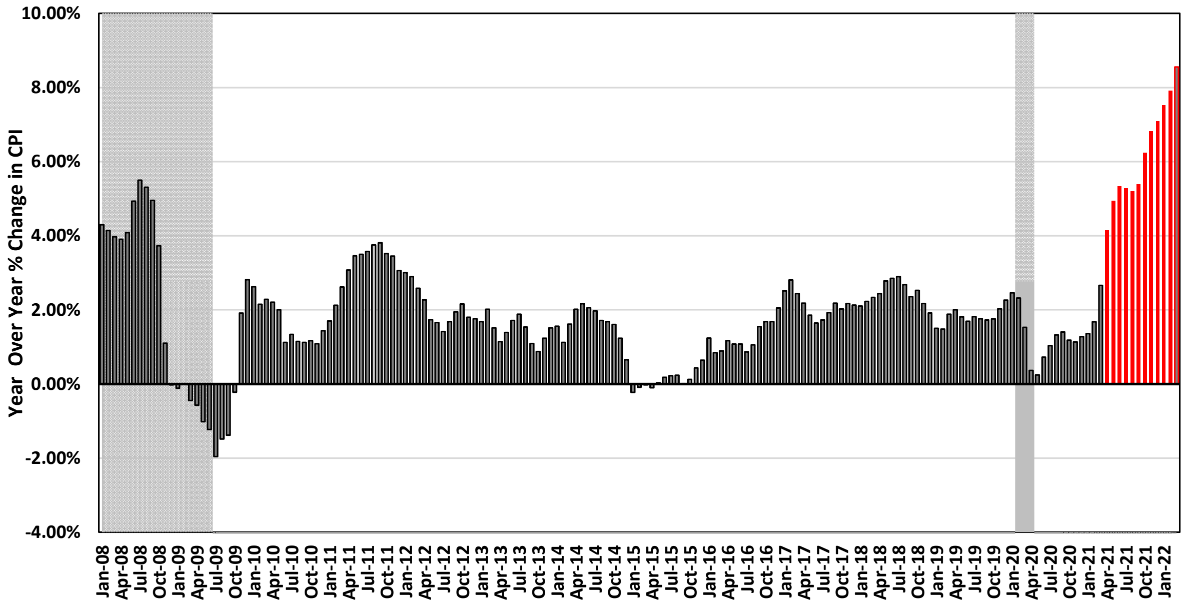
B. Inflationary Expectations in Current and Projected Market Conditions

Q27. Is the increase in inflation significant?

A27. Yes. As shown in Figure 3, the YOY change in the Consumer Price Index ("CPI") published by the Bureau of Labor statistics has increased steadily over the past year rising from 1.37 percent in January 2021 to 8.56 percent in March 2022. The 8.56 percent YOY in the CPI in March 2022 is the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008.

[17] Source: Federal Reserve, Transcript of Chair Powell's Press Conference Opening Statement, (May 4, 2022), at 3.

Figure 3: Consumer Price Index – YOY Percent Change – January 2008 – March 2022[18]



Q28. What are the expectations for inflation over the near-term?

A28. In his press conference following the May 4, 2022 meeting, Chairman Powell noted that "[i]nflation is much too high and we understand the hardship it is causing, and we're moving expeditiously to bring it back down".[19] Therefore, investors expect inflation to remain elevated over the near-term. One measure of investors' expectations regarding inflation is the breakeven inflation rate calculated as the spread between the yield on a Treasury bond and the yield on a Treasury Inflation-Protected bond, since a Treasury Inflation-Protected bond would account for the effect of inflation. The maturity of the bond selected would then reflect investors' views of inflation during the holding period of the bond. For example, the 10-year breakeven inflation rate calculated as the spread between the 10-year Treasury bond yield and the 10-year Treasury Inflation-Protected bond yield

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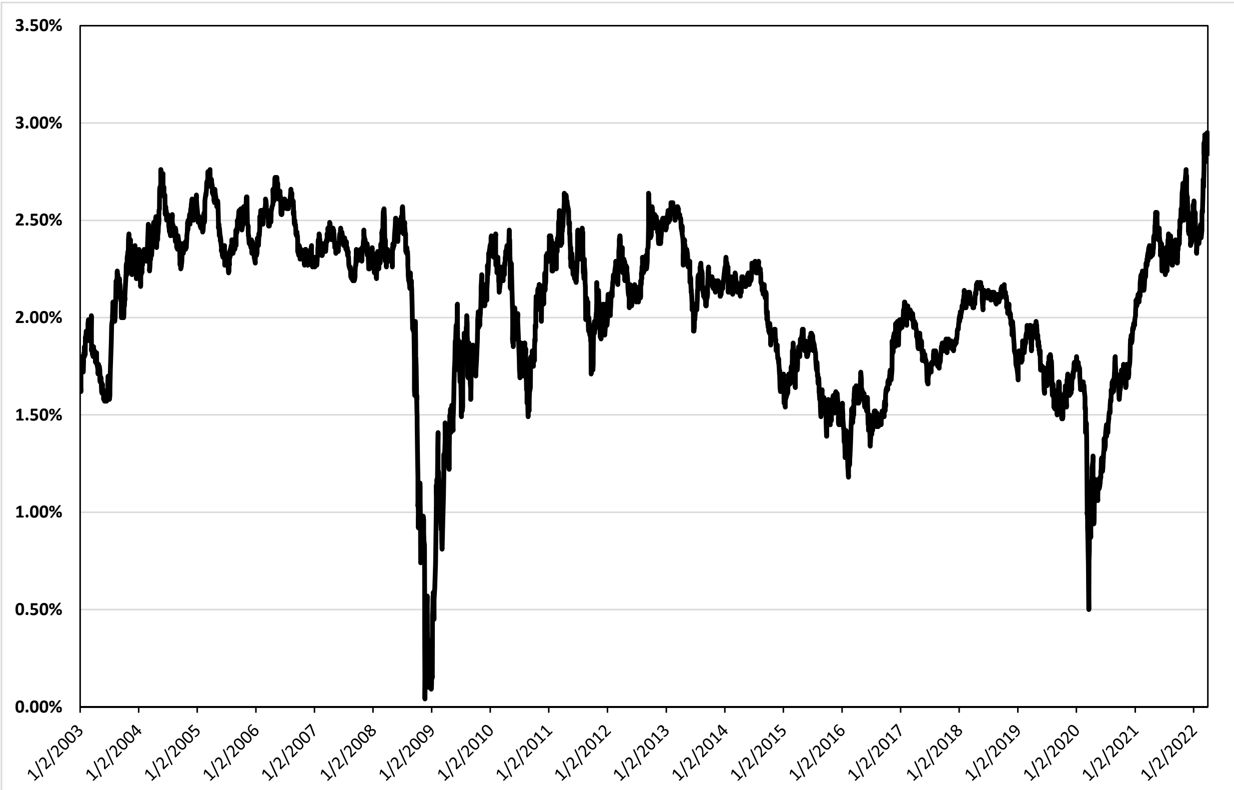
[18] Source: Bureau of Labor Statistics, shaded area indicates a recession.
[19] Source: Federal Reserve, Transcript of Chair Powell's Press Conference Opening Statement, (May 4, 2022), at 1.

would reflect investors' expectations of inflation over the next 10 years. As shown in Figure 4 below, the 10-year breakeven inflation rate is currently greater than any level seen since January 2003. Furthermore, the 10-year breakeven inflation rate as of March 31, 2022 was 2.84 percent indicating that investors expect inflation will remain well above the Federal Reserve's 2 percent target over the next 10 years. There are many factors as to why inflation is expected to remain elevated, Kiplinger recently noted a few factors including supply shortages due to COVID-19 and Russia's war in Ukraine which led them to forecast an inflation rate of 5.5 percent for 2022:

> The surge in gasoline prices in March boosted annual inflation to 8.5%, the highest in 40 years. This is likely to be the peak for the year, with inflation beginning to ease soon. But it will end the year at a still high 5.5%. The inflation rate will ease because oil prices are coming down off their peaks, though they remain high. Even if the war in Ukraine ends soon, disincentives to imports of Russian oil and gas will likely continue for quite a while. Ukraine is also a major world producer of wheat. Those prices have surged 40% this year. Other grain and meat prices are also at double or triple their previous long-term averages. Plus, there are expectations of continued upward price pressures on rent, housing costs and prices of many services, as the pandemic eases and demand rebounds.[20]

[20] Payne, David, "Inflation Rate Will Ease, But Prices Will Remain High," Kiplinger, April 13, 2022.

Figure 4: 10-year Breakeven Inflation Rate – Janaury 2003 – March 2022[21]



C. The Effect of Inflation on Interest Rates and the Investor-Required Return

Q29. What effect will inflation have on long-term interest rates?

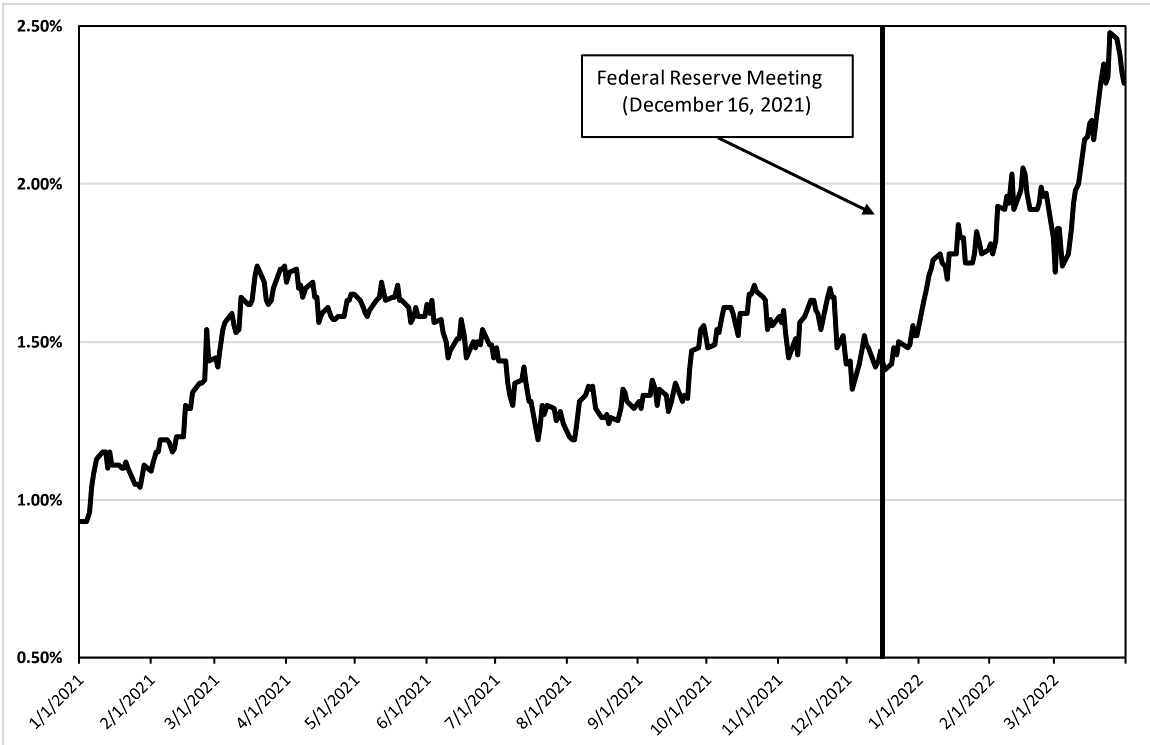
A29. Inflation and the Federal Reserve's normalization of monetary policy will likely result in increases in long-term interest rates. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect increased levels of inflation, they will require higher yields to compensate for the increased risk of inflation, which means interest rates will increase.

[21] Federal Reserve Bank of St. Louis, 10-Year Breakeven Inflation Rate [T10YIE], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10YIE, March 31, 2022.

Q30. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A30. Yes, they have. As shown in Figure 5, since the Federal Reserve's December 2021 meeting, as the process of normalizing monetary policy has accelerated to respond to inflation, the yield on the 10-year Treasury bond has increased over 90 basis points from 1.47 percent on December 15, 2021 to 2.38 percent on April 1, 2022. The increase is due to the Federal Reserve's announcements at the December 2021, January 2022 and March 2022 meetings and the continued increased levels of inflation that are now expected to persist much longer than the Federal Reserve and investors had originally projected.

Figure 5: 10-Year Treasury Bond Yield – Janaury 2021 – March 2022[22]



Q31. What have equity analysts said about long-term government bond yields?

A31. Several equity analysts have noted that they expect economic conditions to continue to improve and thus the yields on long-term government bonds to continue to increase through the end of 2022. As shown in Figure 6, according to various equity analysts, the yield on the 10-year Treasury Bond is expected to range from 2.70 percent to 2.80 percent in 2022, and the current 30-day average yield on the 10-year Treasury Bond as of March 31, 2022 is already 2.08 percent and was trading close to 2.90 percent as of April 29, 2022.

[22] S&P Capital IQ Pro.

Figure 6: Equity Analysts Forecast of the 10-year Treasury Yield

	Actual
30-Day Average as of March 31, 2022	2.08%
	2022 Forecast
Credit Suisse[23]	2.70%
Goldman Sachs[24]	2.70%
Blue Chip Financial Forecasts (Consensus Estimate)[25]	2.80%
BMO Economics[26]	2.70%

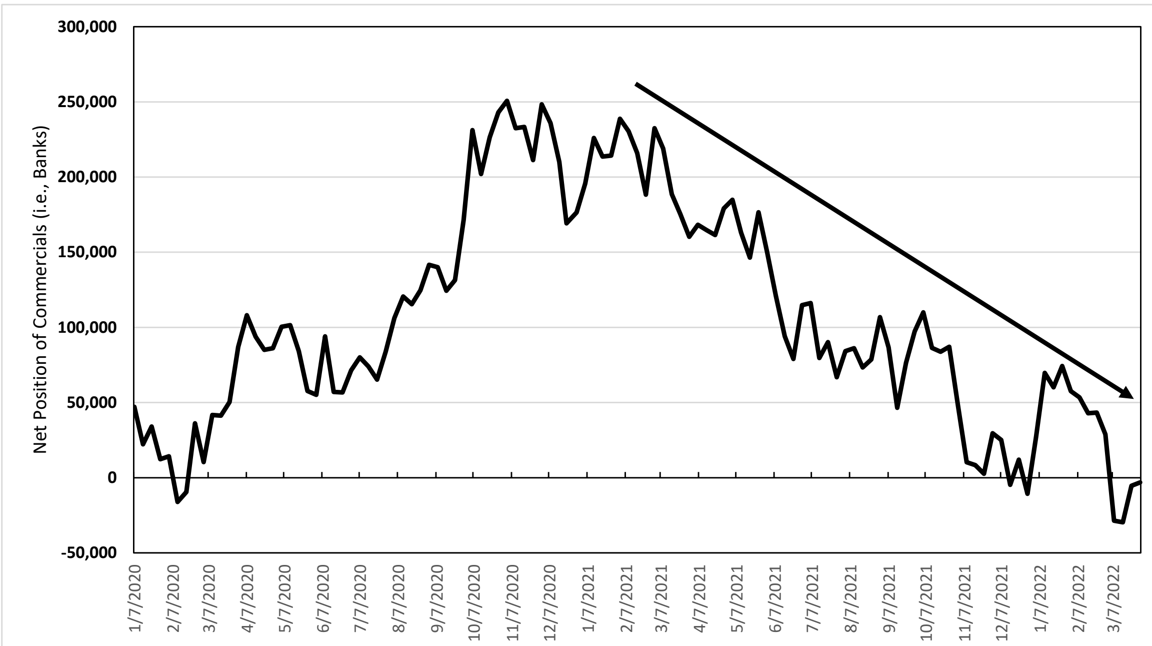
Q32. Have you considered any additional indicators that may imply long-term interest rates are expected to increase?

A32. Yes, I have. I considered the net position of commercials (i.e., banks) in U.S. Treasury Bond futures contracts as reported in the Commitment of Traders ("COT") Report produced by the Commodity Futures Trading Commission ("CFTC"). A net position is defined as the total number of long positions in a futures contract minus the total number of short positions in a futures contract. A long position means that an investor agrees to purchase an asset in the future at a specified price today and therefore profits if the price of the underlying asset increases. Conversely, short position is when an investor agrees to sell an asset at a time in the future at a specified price today and profits if the price of the asset declines. Therefore, if banks are increasing the number of short positions and thus have a declining net position, the banks are assuming that the price of the asset will decline.

23 Reuters, "U.S. 10-year yield to hit 2.7% this year - Credit Suisse," February 16, 2022.
24 Worrachate, Anchalee. "Goldman Sees Higher U.S. Treasury Yields, Curve Inversion." Bloomberg.com, March 25, 2022.
25 Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2.
26 BMO Economics, "North American Outlook: Out of the Pandemic and Into the Fire," March 31, 2022.

As shown in Figure 7, the net position of banks in U.S. Treasury Bonds has been decreasing since the end of 2020. Therefore, banks are forecasting a decrease in the price of long-term government bonds and thus the yields (which are inversely related to the price) to increase over the near-term.

Figure 7: Commitment of Traders Report – Net Position of Commercials (i.e., Banks) in U.S. Treasury Bond Futures Contracts[27]



D. Expected Performance of Utility Stocks and the Investor-Required ROE on Utility Investments

Q33. Are utility share prices correlated to changes in the yields on long-term government bonds?

A33. Yes, interest rates and utility share prices are inversely correlated which means, for example, that an increase in interest rates will result in a decline in the share prices of

[27] Commitment of Traders Report, as of March 31, 2022 - https://www.cftc.gov/MarketReports/CommitmentsofTraders/HistoricalCompressed/index.htm

utilities. For example, Goldman Sachs and Deutsche Bank recently examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman 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).[28]

Q34. Have electric utility stock prices recently increased?

A34. Yes. Utility stock prices had trended down as interest rates moved higher; however, as a result of the political turmoil associated with the war in Ukraine, investors have recently returned to utility stocks as a safe haven seeking to lower risk, resulting in higher electric utility stock prices and thus lower dividend yields.

Q35. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A35. Even with the recent increase in electric utility stock prices, equity analysts project that utilities are expected to continue to underperform the broader market as interest rates increase. For example, in its most recent Big Money poll, which closed in mid-April and surveyed 112 money managers regarding the outlook for the next twelve months, the professional investors selected the utility sector as the least attractive of all industries for investment.[29] In addition, Fidelity recently recommended underweighting the utility sector and noted that it classified the sector as underweight due to a combination of "poor

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[28] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, 11 Mar. 2021, www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.

29 Jasinski, Nicholas, Bearish Now, Bullish Later: How Investors Are Sizing Up Stocks, Barron's, updated April 24, 2022.

fundamentals and expensive valuations".[30] Furthermore, regarding the recent increase in utility share prices, Fidelity stated that:

> Energy stocks have garnered a lot of attention, but in February utilities was the only sector with monthly returns in the 90th percentile of its historical range. In the past, powerful utilities rallies have signaled investors getting too defensive. The market typically has gained, and utilities have underperformed, in 12-month periods after top-decile monthly relative returns for the sector.[31]

Q36. Have you reviewed any market indicators that may imply that utilities will underperform over the near-term?

A36. Yes, I have. As discussed above, the utility sector is considered a "bond proxy" or a sector in which investors are attracted as a safe haven alternative to bonds, and utility stock prices are therefore inversely related to changes in interest rates. For example, the utility sector tends to perform well when interest rates are low since the dividend yields for utilities offer investors the prospect of higher returns when compared to the yields on long-term government bonds. Conversely, the utility sector underperforms as the yields on long-term government bonds increase and the spread between the dividend yields on utility stocks and the yields on long-term government bonds decreases. Therefore, I examined the yield spread between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through April 2022. 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 8, the yield spread as of April 8, 2022 was 0.00 percent indicating that yield on the 10-year Treasury Bond is equivalent to the dividend yield for the S&P Utilities

30 Fidelity, "Top sectors to watch in Q2," May 4, 2022.

31 *Ibid*

Index which is the smallest yield spread since at least 2010. Furthermore, the current yield spread of 0.00 percent is well below the long-term average since January 2010 of 1.47 percent. Given that the yield spread is currently well below the long-term average as well as the expectation that interest rates will continue to increase, it is reasonable to conclude that utility sector will underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the low yields on long-term government bonds will begin to rotate back into government bonds as the yields on long-term government bonds continue to increase thus resulting in a decrease in the share prices of utilities.

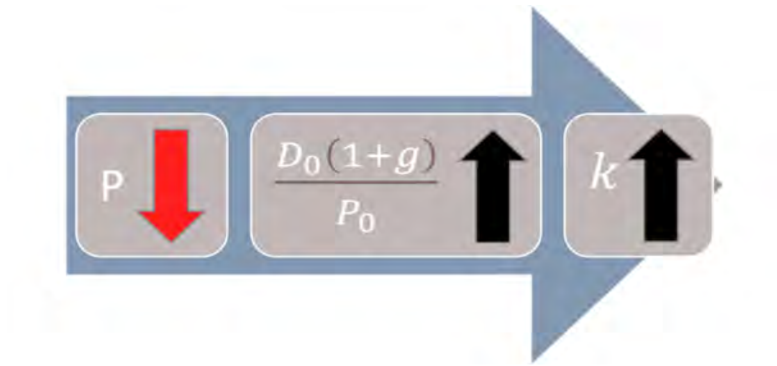
Figure 8: Yield Spread between the Dividend Yield on the S&P Utilities Index and the Yield on the 10-year Treasury Bond – January 2010 – April 2022[32]

Q37. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A37. As discussed above, the Federal Reserve is currently normalizing monetary policy in response to inflation which is expected to increase long-term government bond yields. If interest rates increase as expected, then the share prices of utilities will decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices, is likely to understate the cost of equity. For example, Figure 9, below summarizes the effect of price on the dividend yield in the Constant Growth DCF model.

[32] Bloomberg Professional and S&P Capital IQ Pro.

Figure 9: The Effect of a Decline in Stock Prices on the Constant Growth DCF Model



A decline in stock prices will increase the dividend yields and thus the estimate of the ROE produced by the Constant Growth DCF model. Therefore, this expected change in market conditions supports consideration of the range of ROE results produced by the mean to mean-high DCF results since the mean DCF results would likely understate the cost of equity during the period that the Company's rates will be in effect. Moreover, prospective market conditions warrant consideration of other ROE estimation models such as the CAPM and ECAPM, which may better reflect expected market conditions. For example, two out of three inputs to the CAPM (i.e., the market risk premium and risk-free rate) are forward-looking.

Q38. Have state regulatory commissions considered market events and the utility's ability to attract capital in determining the equity return?

A38. Yes. In a recent rate case for Consumers Energy Company, the Michigan Public Service Commission ("Michigan PSC") noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past. Specifically, the Michigan PSC stated that:

> [i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. *It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE*.[33]

The Michigan PSC references "global events" and the overall effect the events could have on the ability of a utility to access capital. Consistent with the Michigan PSC's views, it is important to consider current market conditions and the impact of those conditions on the access to and cost of capital, and to position utilities to be able to maintain access in rapidly changing market conditions.

E. Conclusion

Q39. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A39. Over the near-term, investors expect long-term interest rates to increase 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, an increase in long-term government bond yields will likely result in a decline in utility share prices, which is the reason a number of equity analysts expect the utility sector to

[33] Michigan Public Service Commission Order, Cause No. U-20697, Consumers Energy Company, at 165 (Dec. 17, 2020).

underperform over the near-term. 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. This change in market conditions also supports the use of other ROE estimation models such as the CAPM and the ECAPM, which may better reflect expected market conditions.

V. PROXY GROUP SELECTION

Q40. Why have you used a group of proxy companies to estimate the Cost of Equity for Montana-Dakota?

A40. In this proceeding, we are focused on estimating the Cost of Equity for Montana-Dakota's electric utility operations. Since the Cost of Equity is a market-based concept, and given that Montana-Dakota does 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 Montana-Dakota in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if Montana-Dakota's electric utility operations in North Dakota did constitute the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given period of time. 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 ROE for Montana-Dakota.

Q41. Please provide a brief profile of Montana-Dakota.

A41. Montana-Dakota Utilities Co. is a wholly owned subsidiary of MDU Resources. It provides regulated retail natural gas and/or electric service to parts of Montana, North Dakota, South Dakota, and Wyoming. The Company's electric utility operations in North Dakota serves approximately 93,344 residential, general, lighting and municipal customers. As of December 31, 2021, the Company's net utility electric plant in North Dakota was approximately 903.6 million.[34] In addition, the Company had total electric sales in North Dakota in 2021 of approximately 2,075,391,863 MWh, composed of 35.94 percent residential, 61.02 percent general and 3.04 percent lighting and municipal customers.[35] For the Company's parent entity, MDU Resources, North Dakota accounted for 64.00 percent of its total electric retail sales revenue in 2021, while Montana operations were 22.00 percent, South Dakota was 5.00 percent, and Wyoming was 9.00 percent.[36] Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Stable) from S&P and BBB+ (Outlook: Stable) from Fitch[37].

Q42. How did you select the companies included in your proxy group?

A42. I began with the group of 36 companies that *Value Line* classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends because such companies cannot be analyzed using the Constant Growth DCF model.

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34 Montana-Dakota Utilities Co. 2021 Annual Report to the North Dakota Public Service Commission, at Intrastate Return on Equity, at 2.

35 Montana-Dakota Utilities Co. 2021 Annual Report to the North Dakota Public Service Commission, at Miscellaneous, at 1.

36 MDU Resources Group, Inc., Form 2021 SEC Form 10-K at 12.

37 S&P and Fitch Ratings accessed March 31, 2022.

- have positive long-term earnings growth forecasts from at least two equity analysts.
- have investment grade long-term issuer ratings from both S&P and Moody's.
- own generation assets included in rate base
- have more than 40 percent of company-owned generation;
- derive more than 60 percent of total operating income from regulated operations;
- derive more than 80 percent of their total regulated operating income from regulated electric operations; and
- were not party to a merger or transformative transaction during the analytical period considered.

Q43. Did you exclude any other companies from the proxy group?

A43. Yes. I also excluded Pinnacle West Capital Corporation ("PNW") and Hawaiian Electric Industries, Inc. ("HE"). For PNW, the share price decreased approximately 24 percent over a two-month period from October through November 2021 resulting from a negative regulatory decision for its largest operating company, Arizona Public Service Company ("APS"). Therefore, similar to the reason that I exclude transformative transactions; because the stock price can be affected by one-time events, I also excluded PNW from the proxy group.

HE's operations are concentrated on the islands of Hawaii; therefore, the company faces geographic concentration risk. As HE noted in the company's 2021 Form10-K:

> The Company is subject to the risks associated with the geographic concentration of its businesses and current lack of interconnections that could result in service interruptions at the Utilities or higher default rates on loans held by ASB [American Savings Bank].[38]

[38] Hawaii Electric Industries, Inc., 2021 Form 10-K, at 23.

The increased risk of service interruptions resulting from HE's geographic location which could result in revenue loss and increased costs is a risk unique to HE and would not apply to utilities located on the U.S. mainland. Furthermore, HE's unregulated operations which represent approximately 33 percent of the company's operation income in 2021 are concentrated in the banking sector through the ownership of American Savings Bank ("ASB").[39] ASB also only operates on Hawaii; thus, all of the company's consumer and commercial loans are to customers on Hawaii. If Hawaii were to face an adverse economic or political event, ASB could face severe financial effects given the company's geographic concentration in Hawaii.[40] As a result, I have excluded HE from my proxy group considering HE's unique geographical risks.

Q44. What is the composition of your proxy group?

A44. 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 in Figure 10 below .

Figure 10: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG

39 *Id.*, at 86.
40 *Id.*, at 20.

IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q45. Please briefly discuss the ROE in the context of the regulated rate of return.

A45. The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the cost 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.

Q46. How is the required ROE determined?

A46. While the cost of debt can be directly observed, the cost of equity and the required ROE are market-based and, therefore, must be estimated based on observable market information. The required ROE is determined by using one or more analytical techniques that rely on market data to quantify investor expectations regarding the range of required equity returns. Informed judgment is applied, based on the results of those analyses, to determine where within the range of results the cost of equity for a company falls. As a general proposition, the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets, the proxy group companies, and the subject company's risk profile.

Q47. What methods did you use to determine the Company's ROE?

A47. I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, and the Bond Yield Plus Risk Premium Analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q48. Why is it important to use more than one analytical approach?

A48. 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. A number of models have been developed to estimate the Cost of Equity, and I use multiple approaches to estimate the Cost of Equity. As a practical matter, however, all of the models available for estimating the Cost of Equity are subject to limiting assumptions or other methodologies constraints. Consequently, many well-regarded finance texts recommended using multiple approaches when estimating the Cost of Equity. For example, Copeland, Koller, and Murrin[41] suggest using the CAPM and

[41] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

Arbitrage Pricing Theory model, while Brigham and Gapenski[42] recommend the CAPM, DCF, and "bond yield plus risk premium" approaches.

Q49. Do current market conditions support the use of more than one analytical approach?

A49. Yes. The effect of the low interest rate environment can be seen in the low dividend yields for utilities which result in DCF cost of equity estimates that are understating the forward-looking cost of equity. The CAPM and Bond Yield Plus Risk Premium method offer some balance to the sensitivity of the DCF model to low Treasury yields. Low interest rates might also affect the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates, (*i.e.*, it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. However, when applied appropriately, the CAPM will take into account the relationship between ROE and interest rates through the market risk premium component. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates, especially the DCF analysis, and where possible consider using projected market data in the models to estimate the return for the forward-looking period.

Q50. Are you aware of any regulatory commissions that have recognized the importance of considering the results of multiple models?

A50. Yes, several regulatory commissions consider the results of multiple ROE estimation methodologies such as the DCF, CAPM, and ECAPM in determining the authorized ROE,

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[42] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

including the Minnesota Public Utilities Commission ("Minnesota PUC")[43], the Michigan Public Service Commission ("Michigan PSC")[44], the Iowa Utilities Board ("IUB")[45], the Washington Utilities and Transportation Commission ("Washington UTC")[46] and the New Jersey Board of Public Utilities ("NJBPU")[47]. For example, the Washington UTC has repeatedly emphasized that it "places value on each of the methodologies used to calculate the cost of equity and does not find it appropriate to select a single method as being the most accurate or instructive."[48] The Washington UTC has also explained that "[f]inancial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies."[49]

Additionally, in its recent order for DTE Gas Company ("DTE Gas") in Case No. U-18999, the Michigan PSC considered the results of each of the models presented by the ROE witnesses, which included the DCF, CAPM, and ECAPM in the determination of the authorized ROE.[50] The Commission also considered authorized ROEs in other states, increased volatility in capital markets and the company-specific business risks of DTE Gas.

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[43] Docket No. G011/GR-17-563, Findings of Fact, Conclusions and Order, at 27; Docket No. E015/GR-16-664, Findings of Fact, Conclusions and Order, at 60-61.

[44] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

[45] Iowa Utilities Board, Iowa-American Water Company, RPU-2016-0002, Final Decision and Order issued February 27, 2017, at 35.

[46] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

[47] NJBPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

[48] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013).

[49] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

[50] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

Q51. What are your conclusions about the results of the DCF and CAPM models?

A51. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historically low dividend yields that are not expected to continue over the period that the new rates will be in effect will underestimate the ROE for Montana-Dakota.

Furthermore, as discussed in Section IV above, long-term interest rates have increased since August 2020 and this trend is expected to continue as the Federal Reserve normalizes monetary policy in response to increased inflation. Therefore, the use of current averages of Treasury bond yields as the estimate of the risk-free rate in the CAPM is not appropriate since recent market conditions are not expected to continue over the long-term. Instead, analysts should rely on projected yields of Treasury Bonds in the CAPM. The projected Treasury Bond yields result in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q52. Please describe the DCF approach.

A52. 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:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

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.

Q53. What assumptions are required for the Constant Growth DCF model?

A53. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ("P/E") ratio; and (4) a discount rate greater than the expected growth rate. To the extent any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q54. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A54. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of March 31, 2022.

Q55. Why did you use three averaging periods for stock prices?

A55. In my Constant Growth DCF model, I use an average of recent trading days to calculate the price term (P_0) in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, as discussed above, recent market data is not representative of expected market conditions over the long-term. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the median to median-high results produced by my Constant Growth DCF model.

Q56. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A56. Yes, I did. 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.

Q57. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A57. In its Constant Growth form, the DCF model (i.e., Equation [2]) assumes a single long-term growth rate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the dividend 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.

Q58. What sources of long-term growth rates did you rely on in your Constant Growth DCF model?

A58. My Constant Growth DCF model incorporates the following sources of long-term growth rates: (1) consensus long-term earnings growth estimates from Zacks Investment Research; (2) consensus long-term earnings growth estimates from Thomson First Call (provided by Yahoo! Finance); and (3) long-term earnings growth estimates from Value Line.

Q59. How did you calculate the expected dividend yield?

A59. I adjusted the dividend yield to reflect the growth rate that was being used in that particular scenario. This ensures that the growth rate used in the dividend yield calculation and the growth rate used as the "g" term of the DCF model are internally consistent.

Q60. How did you calculate the range of results for the Constant Growth DCF model?

A60. I calculated the low DCF result using the minimum growth rate (i.e., the lowest of the Thomson First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q61. Please summarize the results of your Constant Growth DCF analyses.

A61. Figure 11 (see also Exhibit No. ___(AEB-2), Schedule 4), present the results of the Constant Growth DCF analyses using a 30-Day, 90-Day, or 180-Day average for the closing stock price of the proxy groups as of March 31, 2022. The mean results range from 9.34 percent to 9.42 percent. The mean high results range from 10.25 percent to 10.33 percent. The median and median high results range from 9.50 percent to 9.56 percent and 10.18 percent to 10.24 percent respectively.

Figure 11: Summary of Constant Growth DCF Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.33%	9.34%	10.25%
90-Day Average	8.36%	9.37%	10.28%
180-Day Average	8.41%	9.42%	10.33%
	Median Low	Median	Median High
30-Day Average	7.98%	9.50%	10.18%
90-Day Average	8.02%	9.40%	10.21%
180-Day Average	8.15%	9.56%	10.24%

Q62. What are your conclusions about the results of the Constant Growth DCF model?

A62. As discussed previously, one primary assumption of the DCF model is a constant P/E ratio. 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 increase, it is important to consider the results of the DCF models with caution because the DCF tends to understate the cost of equity in rising interest rate and higher inflationary environments, which, as discussed previously, currently exist. Therefore, while I have given weight to the results of the Constant Growth DCF model, my recommendation also gives weight to the results of other ROE estimation models.

C. Capital Asset Pricing Model

Q63. Please briefly describe the Capital Asset Pricing Model ("CAPM")

A63. 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 or "systematic" risk of that security. Systematic risk is the risk inherent in the entire market or market segment. This form of risk cannot be diversified away using a portfolio of assets. Non-systematic risk is the risk of a specific company that can be mitigated through portfolio diversification.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free ROR; and

r_m = the required return on the market as a whole.

In this specification, the term ($r_m - r_f$) represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic risk. Systematic risk is measured by Beta. Beta is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market. 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.

Q64. What risk-free rate did you use in your CAPM analysis?

A64. I relied on three sources for my estimate of the risk-free rate: (1) the current 30 day average yield on 30-year U.S. Treasury bonds (i.e., 2.37 percent);[51] (2) the projected 30-year U.S. Treasury bond yield for Q3 2022 through Q3 2023 (i.e., 3.12 percent);[52] and (3) the projected 30-year U.S. Treasury bond yield for 2023 through 2027 (i.e., 3.40 percent).[53]

Q65. Would you place more weight on one of these scenarios?

A65. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward-looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. While I have included the results of a CAPM analysis that relies on the current average risk-free

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51 Bloomberg, as of March 31, 2022

52 Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2.

53 Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.

rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q66. What beta coefficients did you use in your CAPM analysis?

A66. As shown in Exhibit No. ___(AEB-2), Schedule 5, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported by Bloomberg were calculated using ten years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Additionally, as shown in Exhibit No. ___(AEB-2), Schedule 6, I also considered an additional CAPM analysis which relies on the long-term average utility Beta coefficient for the companies in my proxy group. 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 2021.

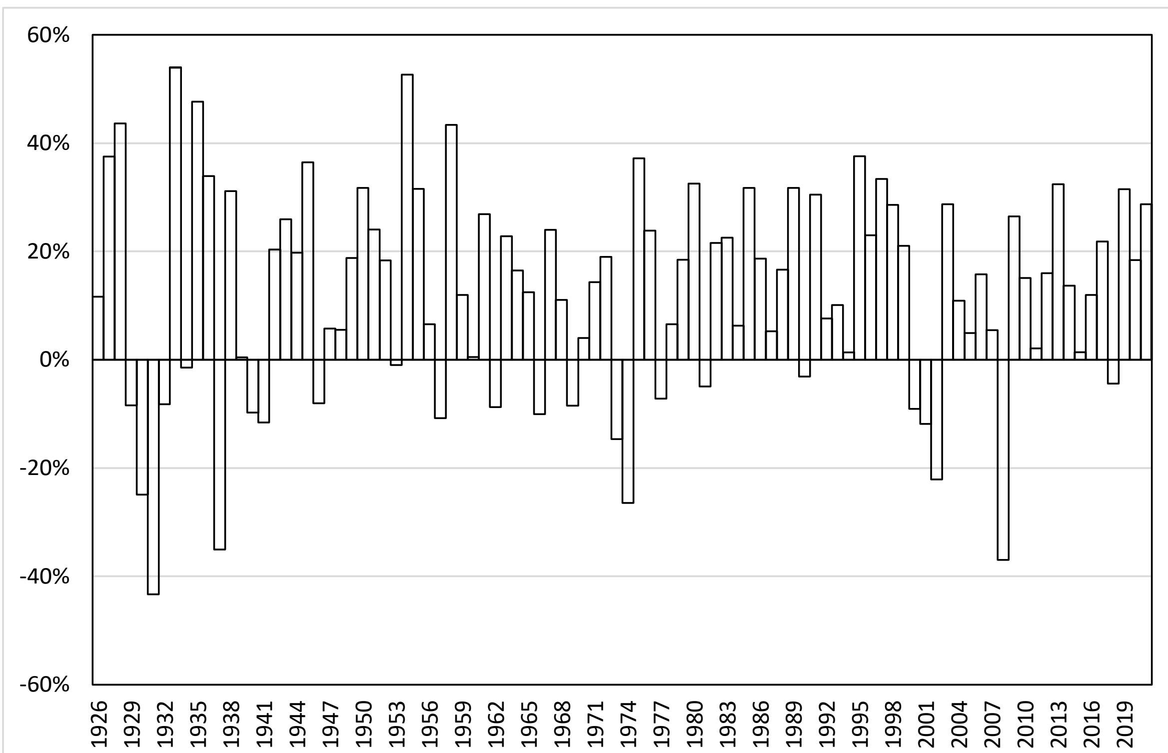
Q67. How did you estimate the Market Risk Premium in the CAPM?

A67. I estimated the Market Risk Premium ("MRP") 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 return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my testimony for 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 10.99 percent, the estimated required market return for the S&P 500 Index is 12.68 percent.

Q68. How does the current expected market return of 12.68 percent compare to observed historical market returns?

A68. Given the range of annual equity returns that have been observed over the past 96 years (shown in Figure 12 below), a current expected return of 12.68 percent is not unreasonable. In 50 of the past 96 years (i.e., in approximately half of all observations), the realized total equity return was at least 12.68 percent or greater.

Figure 12: Realized U.S. Equity Market Returns (1926-2021)[54]



Q69. Did you consider another form of the CAPM in your analysis?

A69. Yes. I have also considered the results of an Empirical CAPM ("ECAPM" or alternatively referred to as the Zero-Beta CAPM)[55] in estimating the cost of equity for MDU-ND. The ECAPM calculates the product of the adjusted Beta coefficient and the market risk

[54] Depicts total annual returns on large company stocks, as reported in the 2022 Duff & Phelps SBBI Yearbook.
[55] See e.g., Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

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:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE

β = Adjusted Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

In essence, the Empirical form of the CAPM 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; 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.[56]

As with the 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 Bloomberg, Value Line and long-term average Beta coefficients.

[56] *Id.*, at 191.

Q70. What are the results of your CAPM analyses?

A70. As shown in Figure 13 (see also Exhibit No. ___(AEB-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.04 percent to 11.63 percent. The ECAPM analysis results range from 10.70 percent to 11.89 percent.

Figure 13: CAPM and ECAPM Results

CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.51%	11.60%	11.63%
Bloomberg Beta	10.71%	10.85%	10.90%
Long-term Avg. Beta	10.04%	10.24%	10.31%
ECAPM			
Value Line Beta	11.80%	11.87%	11.89%
Bloomberg Beta	11.20%	11.31%	11.35%
Long-term Avg. Beta	10.70%	10.85%	10.90%

D. Bond Yield Plus Risk Premium Analysis

Q71. Please describe the Bond Yield Plus Risk Premium approach.

A71. 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 a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, 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 used actual authorized returns for electric utility companies as the historical measure of the cost of equity to determine the risk premium.

Q72. Are there other considerations that should be addressed in conducting this analysis?

A72. Yes. 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. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). 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. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[57]

Q73. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A73. Yes. Investors are aware of ROE awards 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 Bond Yield Plus Risk Premium 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.

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[57] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

Q74. What did your Bond Yield Plus Risk Premium analysis reveal?

A74. As shown in Figure 14 below, from 1992 through March 2022, 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:

$$RP = a + b(T) \qquad [6]$$

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 allowed ROEs were derived from 681 vertically integrated electric utility rate cases from 1992 through March 2022 as reported by Regulatory Research Associates ("RRA").[58] This equation's coefficients were statistically significant at the 99.00 percent level.

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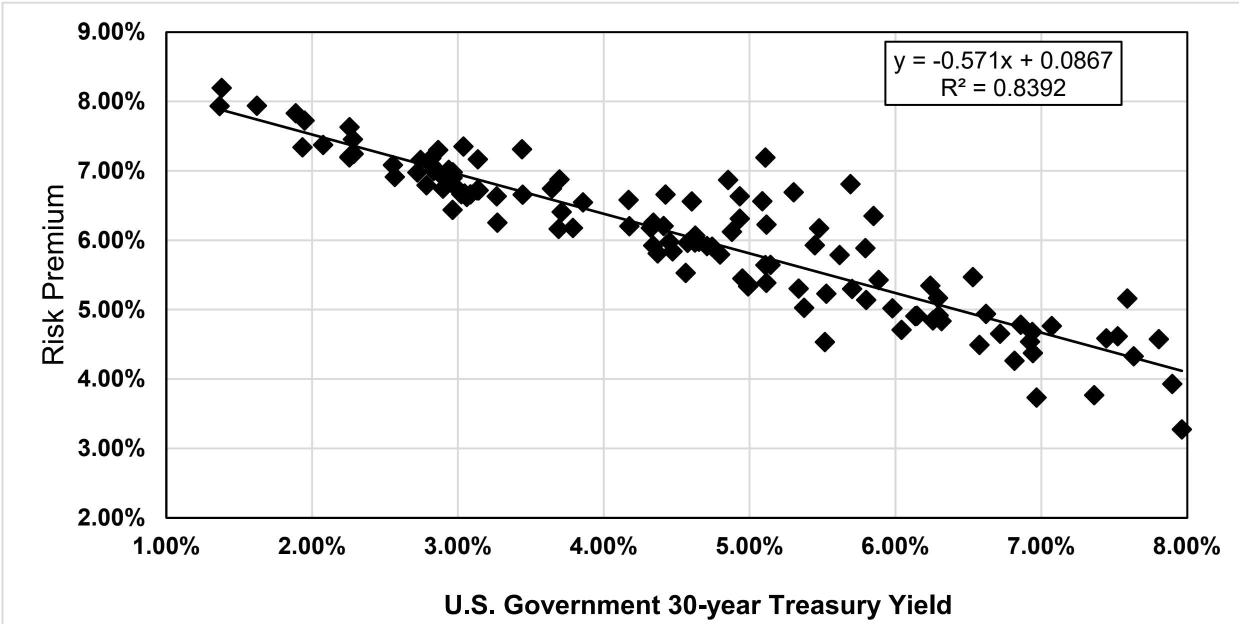
[58] This analysis began with a total of 1,371 cases and was screened to eliminate limited issue rider cases, transmission-only cases, distribution cases, and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 681 cases.

Figure 14: Risk Premium Results



As shown on Exhibit No. ___(AEB-2), Schedule 8, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 2.37 percent), the risk premium would be 7.31 percent, resulting in an estimated ROE of 9.68 percent. Based on the near-term (Q3 2022 – Q3 2023) projections of the 30-year U.S. Treasury bond yield (i.e., 3.12 percent), the risk premium would be 6.88 percent, resulting in an estimated ROE of 10.00 percent. Based on longer-term (2023-2027) projections of the 30-year U.S. Treasury bond yield (i.e., 3.40 percent), the risk premium would be 6.73 percent, resulting in an estimated ROE of 10.13 percent.

Q75. How did the results of the Bond Yield Risk Premium inform your recommended ROE for Montana-Dakota?

A75. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for Montana-Dakota. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the US.

VII. REGULATORY AND BUSINESS RISKS

Q76. Do the DCF, CAPM, and ECAPM results for the proxy group, taken alone, provide an appropriate estimate of the cost of equity for Montana-Dakota?

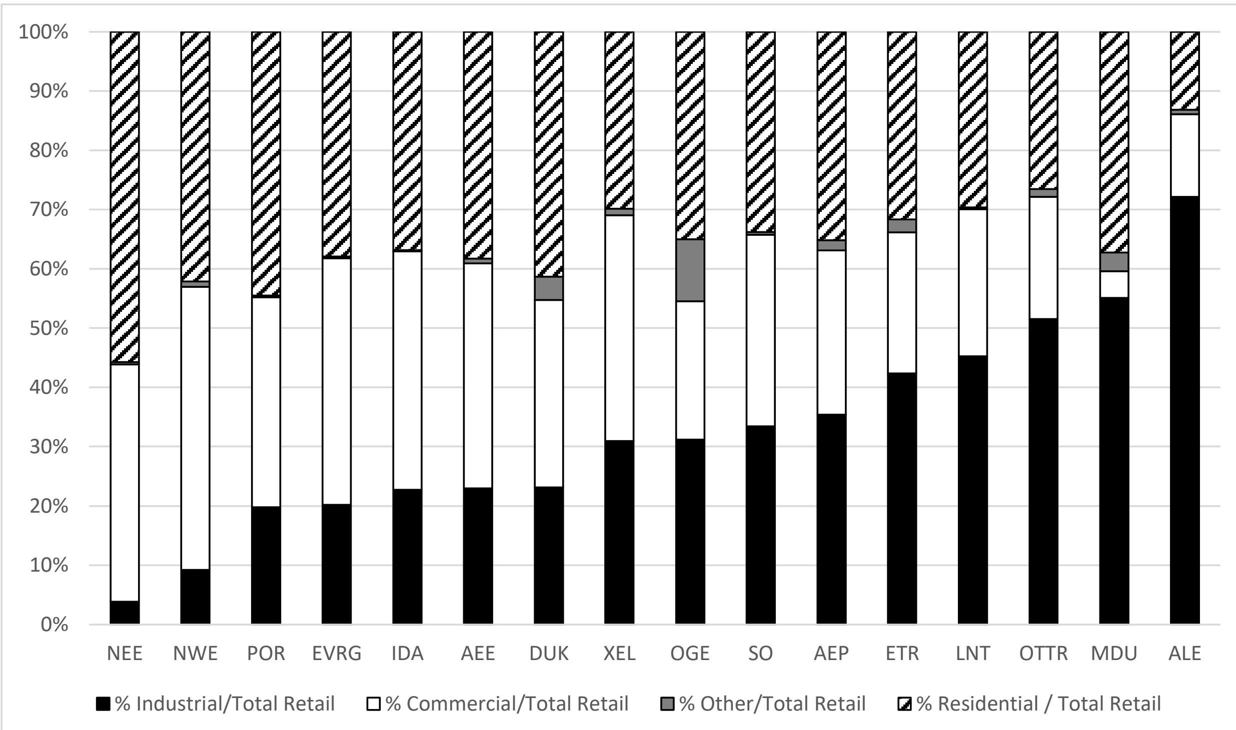
A76. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Service Territory Risk

Q77. Please summarize Montana-Dakota's service territory risk.

A77. As noted above, Montana-Dakota provides electric service to approximately 93,000 customers in North Dakota. The Company's service area is in Central and Western North Dakota, where a number of Montana-Dakota's large general service customers are engaged in crude oil refining, oil and natural gas production, precious metal refining and manufacturing. As I will discuss in more detail below, the oil and natural gas production industry represents a large portion of the economy in North Dakota and supports the Company's residential and commercial customers. Approximately 55 and 56 percent of Montana-Dakota's 2020 and 2021 total retail kWh electric sales in North Dakota were derived from the large general customer class. As shown in Figure 15, Montana-Dakota's large general service sales volume as a percentage of total retail electric sales was higher than all but one of the companies in the proxy group.[59]

Figure 15: Customer Concentration[60]



Q78. How does customer concentration and the Company's service territory affect business risk?

A78. An extremely high concentration of industrial customers results in higher business risk. Since the customers are large, they can represent a significant portion of a company's sales which could be lost if a customer goes out of business. Moreover, the loss of large industrial customers would have an effect on the local economy which would ultimately also affect

59 Does not include "other", commercial or residential customers.
60 Source: S&P Capital IQ Pro - Other sales includes: Total Public Street and Highway Lighting, Other Sales to Public Authorities, Sales to Railroad and Railways, and Interdepartmental Sales.

the sales to residential and commercial customers. As noted by Dhaliwal, Judd, Serfling and Shaikh in their article, *Customer Concentration Risk and the Cost of Equity Capital*:

> Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons. First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock returns to the announcement that a major customer declares bankruptcy. Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt. This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).[61]

Therefore, a company that has a high degree of customer concentration will be inherently riskier than a company that derived income from a larger customer base. Furthermore, as Dhaliwal, Judd, Serfling and Shaik detail in the article, the increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[62]

Q79. Please describe how changes in economic conditions and the interdependent nature of Montana-Dakota's service territory can affect its business risk?

A79. While Montana-Dakota doesn't necessarily depend on any one major customer, it is important to note that one large general service customer in the oil refining industry did comprise 8.87 percent of the Company's 2021 total retail electric sales. Furthermore, the Company has a high concentration of large general service customers. Montana-Dakota's

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[61] Dhaliwal, Dan S., J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh. "Customer Concentration Risk and the Cost of Equity Capital." SSRN Electronic Journal (2016): 1-2. Web.

[62] *Id.,* at 4.

major large general service customers are engaged in industries such as crude oil refining, oil and natural gas production, precious metal refining and manufacturing. Additionally, North Dakota's state economy depends on the oil and natural gas production industry; thus the industry also supports the Company's commercial and residential customers. It is well-documented that the oil and natural gas production industry is very cyclical. Additionally, like other industries, the oil and natural gas production industries are also dependent on the general business cycle. As a result, the production of the customers could change based on general or industry specific economic conditions thereby impacting the customers' energy consumption.

Furthermore, the oil and natural gas production industries could also be facing a downward trend in overall demand over the long-term given state, national and global initiatives to significantly reduce carbon emissions by 2050. In addition, achieving long-term carbon emissions goals requires the steady reduction in emissions over time which means investment is needed in the near-term to begin to reduce the carbon emissions associated with natural gas and oil production. In fact, many companies in the oil and natural gas industry have set their own carbon emissions goals as part of their environmental social governance plans ("ESG"). For example, as noted in a recent article in the Williston Herald, the recent recovery in oil and gas production in North Dakota has been slower than expected given the increase in oil prices due in part to lack of infrastructure to transport the oil and natural gas to market because of companies' carbon gas capture rate goals:

> North Dakota Pipeline Authority Justin Kringstad has talked about this issue [lack of infrastructure to transport the gas to market] frequently. Even 5 percent growth in oil production would be difficult, as things stand now, when it comes to gas

takeaway. That sets a new ceiling, as many companies have set ambitious 98 and 99 percent gas capture rates for their ESG goals.[63]

Companies are currently weighing the cost/benefit of making additional investments over the near-term to increase oil and natural gas production in industries that could face significant declines in demand over time to meet long-term carbon emissions standards. This means the oil and natural gas industry in North Dakota is unlikely to experience significant growth even if commodity prices continue to increase in the near-term. The lack of growth in the near-term and the expected decline in demand for oil and natural gas over the long-term, increases uncertainty and the risk for Montana-Dakota because as I will discuss in more detail below, the economy of the Company's service territory is heavily dependent on the oil and natural gas industry.

Q80. How has employment in the oil and natural gas production industry faired in recent economic conditions?

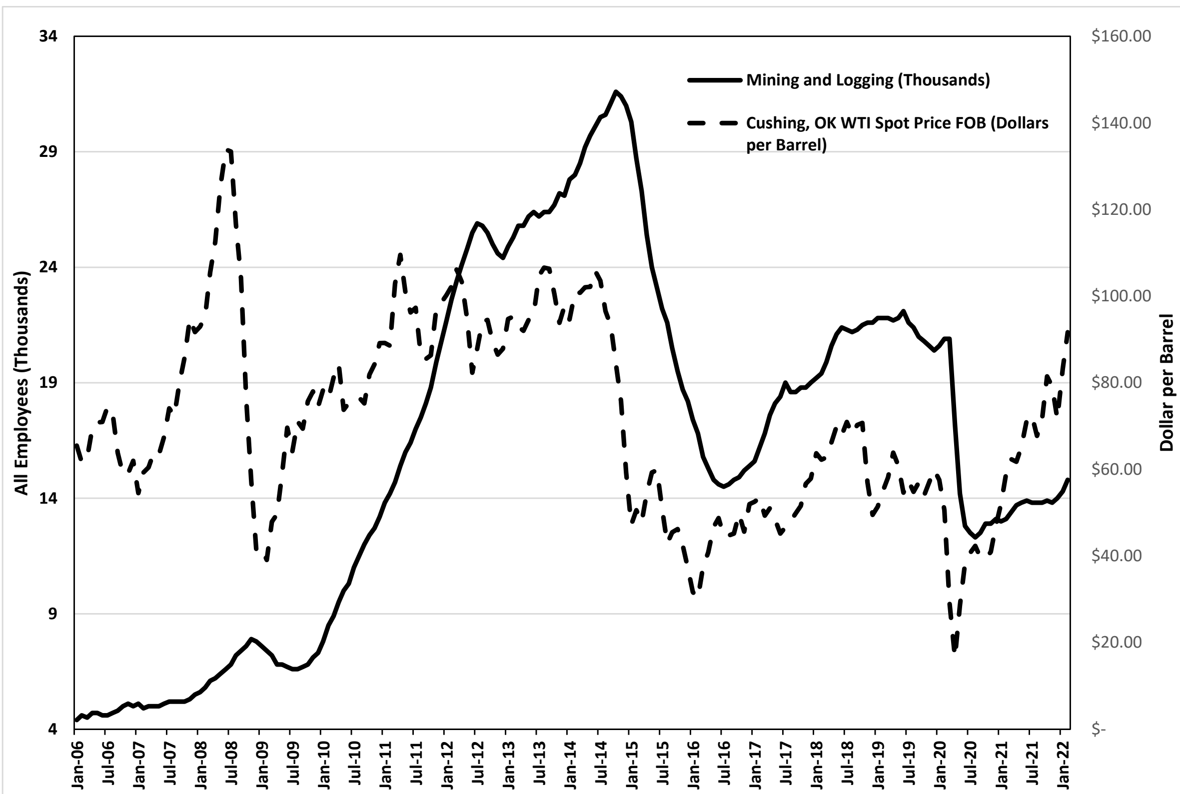
A80. Figure 16 below contains data on mining and logging employment in North Dakota from January 2006 through February 2022. I reviewed mining and logging employment[64] because this data series considers employment in the oil and natural gas production industry. As shown in Figure 16, mining and logging employment in North Dakota has been highly dependent on the price of oil which has been very volatile since 2006. In fact, the decline in the price of oil that began in 2014 and ended in 2016 resulted in a decrease in mining and logging employment in North Dakota from 31,600 in October 2014 to a low

[63] Jean, Renee, "Labor, lack of infrastructure are taking the top off North Dakota's oil and gas recovery," Williston Herald, February 21, 2022. https://www.willistonherald.com/news/oil_and_energy/labor-lack-of-infrastructure-are-taking-the-top-off-north-dakotas-oil-and-gas-recovery/article_68672a6c-935e-11ec-a69e-df734464fe8d.html

[64] Logging is not a significant source of employment in North Dakota; however, the Bureau of Labor Statistics combines mining and logging employment when reporting state level employment statistics.

of 14,500 in July 2016 (i.e., a decline of approximately 50 percent). Furthermore, while oil prices have increased significantly over the past year from the lows in 2020 that occurred as a result of the COVID-19 pandemic, mining and logging employment in North Dakota has not yet similarly recovered due in part to the transportation constraints and carbon emissions standards discussed above.

Figure 16: North Dakota Mining and Logging Employment (Thous.) & West Texas Intermediate Spot Price for a Barrel of Oil[65]



Q81. Are Montana-Dakota's electric sales dependent on the oil refining and natural gas and oil production industries?

A81. Yes. As discussed above, a large portion of the Company's electric sales were to large general service customers some of which operate in the natural gas and oil production and

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[65] Source: Bureau of Labor Statistics and the EIA.

oil refining industries. Moreover, since the economy in Western North Dakota is heavily reliant on the oil and natural gas production industry, Montana-Dakota's commercial and residential customers also rely on the industry for sales and employment. For example, a recent study conducted by North Dakota State University noted the oil and gas industries contribution to the North Dakota economy in 2019:

> Overall, the industry was estimated to support 59,100 jobs in the state having a \$4.45 billion payroll. The industry's economic contribution was estimated at \$40.2 billion in 2019. The industry was estimated to contribute \$25 billion to North Dakota's gross state product. The industry was responsible for \$3.8 billion in local and state government revenues.[66]

The study further noted that while the industry has not recovered to the levels of production seen in 2014, the oil and gas industry is still one of the key contributors to the North Dakota economy.[67] Therefore, fluctuations in the price of oil as a result of the overall business cycle or external events that occur in the industry as well as the expected overall decline in the demand for oil over the long-term due to carbon emission standards and goals could have a significant effect on the economic conditions in Montana-Dakota's service territory in the near- and long-term. This could result in a reduction in sales to large general service customers. Additionally, if large general service customers reduce output, the effect would be compounded by a decline in local employment which would also reduce the electric sales for Montana-Dakota's residential and commercial customers.

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[66] Bangsund, Dean, and Nancy Hodur, "Petroleum Industry's Economic Contribution to North Dakota in 2019," North Dakota State University, February 2021, at 31.

[67] *Ibid.*

Q82. What is your conclusion regarding the Company's service territory and its effect on the cost of equity for Montana-Dakota?

A82. Montana-Dakota is heavily reliant on sales to large general service customers. As noted above, approximately 56 percent of Montana-Dakota's 2021 total electric sales in North Dakota were to large general service customers. This concentration is higher than all but one of the proxy group companies. A high degree of customer concentration increases Montana-Dakota's risk related to customer migration and changes in economic conditions. This risk is greater in Montana-Dakota's service territory because the residential and commercial customers rely on the success of the oil and natural gas production industry for sales and employment. Increased customer and economic diversity decreases the effect that any one customer or industry can have on a company's sales. Thus, Montana-Dakota's service territory, where large general service customers represent a large portion of electric sales and commercial and residential customers rely economically on the success of the one industry segment, implies that Montana-Dakota has an above average risk profile when compared to the companies in the proxy group.

B. Regulatory Environment

Q83. Please explain how the regulatory framework affects investors' risk assessments.

A83. 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.

Q84. Please explain how credit rating agencies consider the regulatory framework in establishing a company's credit rating.

A84. 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. [68]

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." [69] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory environment in which investor-owned regulated utilities operate: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[70]

Q85. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A85. 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."[71] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly

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68 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

69 Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

70 *Id.*, at 1.

71 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 6 (June 23, 2017).

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." [72]

Q86. Have you conducted any analysis of the regulatory framework in North Dakota relative to the jurisdictions in which the companies in your proxy group operate?

A86. Yes. I have evaluated the regulatory framework in North Dakota considering two factors which are important to ensuring Montana-Dakota maintains access to capital at reasonable terms. As I will discuss in more detail below, the two factors are: 1) cost recovery mechanisms which allow a utility to recover costs in a timely manner between rate cases and provide the utility the opportunity to earn its authorized return; and 2) the ability of the Company to earn its authorized ROE because while an authorized ROE may be consistent with the authorized ROEs of other comparable vertically integrated electric utilities, if the Company is unable to earn its authorized ROE, Montana-Dakota's ability to attract capital at reasonable terms could be affected.

1. Cost Recovery Mechanisms

Q87. Have you conducted any 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?

A87. Yes. I selected four mechanisms that are important to provide a regulated utility an opportunity to earn its authorized ROE. These are: 1) test year convention (i.e., forecast vs. historical); 2) method for determining rate base (i.e., average vs. year-end); 3) use of

[72] *Ibid.*

revenue decoupling mechanisms or formula-based rates that mitigate volumetric risk; and 4) prevalence of capital cost recovery between rate cases. The results of this cost recovery assessment are shown in Exhibit No. ___(AEB-2), Schedule 9 and are summarized below.

Test year convention: Montana-Dakota is proposing to use projected test years as of December 31, 2022 and December 31, 2023 in North Dakota which is similar to the proxy group. As shown in Exhibit No. ___(AEB-2), Schedule 9, 50.00 percent of the proxy group provide service in jurisdictions that use a fully or partially forecast test year.

Rate base: Montana-Dakota's rate base in North Dakota is determined based on the average of the beginning and ending test year rate base balances, while 46.15 percent of the operating companies held by proxy group are allowed to use year-end rate base, meaning that the rate base includes capital additions that occurred in the second half of the test year and is more reflective of total net utility plant going forward.

Non-Volumetric Rate Design: Montana-Dakota has not requested approval of a non-volumetric rate design mechanism such as straight fixed variable rate design, a revenue decoupling mechanism or a formula rate plan and thus does not have protection against volumetric risk in North Dakota. However, 44 out of 78 (56.41 percent) of the operating companies held by the proxy group have some form of non-volumetric rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: As discussed above, Montana-Dakota does have capital tracking mechanisms and is proposing to use a fully forecast test year which will allow the Company to recover a portion of its capital expenditures plan. Similarly, 56.41

percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

2. Earned ROE

Q88. Is there evidence that Montana-Dakota has been unable to earn its authorized ROE?

A88. Yes. As shown in Figure 17, Montana-Dakota's electric operations in North Dakota has persistently under-earned its authorized ROE in each year since 2015. Over this period, the average earned ROE on the Company's electric operations in North Dakota was 8.59 percent, as compared with the average authorized ROE of 9.96 percent, for an average under-earning of 137 basis points per year. This under-earning occurred despite the fact that Montana-Dakota relied on a forecast test year and was allowed to recover a portion of qualifying capital investments through capital tracking mechanisms.

Figure 17: Montana-Dakota's Earned vs. Authorized ROE (2015-2021)

	EARNED ROE	AUTHORIZED ROE	EARNINGS DIFFERENTIAL (BPS)
2015	6.88%	10.75%	-387
2016	9.27%	10.75%	-148
2017	9.09%	9.65%	-56
2018	8.89%	9.65%	-76
2019	8.82%	9.65%	-83
2020	9.39%	9.65%	-26
2021	7.83%	9.65%	-182
Average	**8.59%**	**10.02%**	**-137**

Q89. What is your conclusion regarding the regulatory framework in North Dakota as compared with the jurisdictions in which the proxy group companies operate?

A89. 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, year-end rate base, cost recovery trackers and revenue stabilization mechanisms than Montana-Dakota has in North Dakota. While Montana-Dakota relies on a forecast test year and has capital tracking mechanisms, the Company does not have a revenue decoupling mechanism to mitigate volumetric risk and determines rate base using the average method. Additionally, the Company has not earned its authorized ROE since 2015. For these reasons, I conclude that Montana-Dakota has greater than average regulatory risk when compared to the proxy group, indicating that the authorized ROE for Montana-Dakota should be higher than the proxy group median.

C. Flotation Cost

Q90. What are flotation costs?

A90. 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.

Q91. Why is it important to consider flotation costs in the allowed ROE?

A91. 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.

Q92. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A92. 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 cost is incurred prior to the test year but remains 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 Montana-Dakota the opportunity to earn its required ROR in the future.

Q93. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A93. Suppose MDU Resources issues stock with a value of $100, and an equity investor invests $100 in MDU Resources 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 Resources ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU Resources 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.

Q94. Is the date of MDU Resources' last issued common equity important in the determination of flotation costs?

A94. No. As shown in Exhibit No. ___(AEB-2), Schedule 10, MDU Resources 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. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that he should have a reasonable opportunity to earn a return on the full amount of capital that he has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q95. Is the need to consider flotation costs recognized by the academic and financial communities?

A95. 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 ROR. 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.[73]

Q96. How did you calculate the flotation costs for MDU Resources?

A96. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU Resources in its two most recent common equity issuance. These issuance costs were applied to my proxy group. Applying the actual issuance costs for MDU Resources provided in Exhibit No. ___(AEB-2), Schedule 10, to the DCF analysis, the flotation costs are estimated to be 0.13 percent (i.e., 13 basis points).

Q97. Do your final results include an adjustment for flotation cost recovery?

A97. No. I did not make an explicit adjustment for flotation costs to any of my quantitative analyses. Rather, I provide the above result for consideration in my recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, ECAPM and Risk Premium analyses.

[73] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

VIII. CAPITAL STRUCTURE

Q98. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A98. Yes, it is. Assuming other factors are equal, a higher debt ratio increases the risk to 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, who are the residual claimants on the cash flow of the Company. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q99. What is Montana-Dakota's proposed capital structure?

A99. Montana-Dakota's is proposing a projected capitalization for 2022 that is composed of 50.787 percent equity, 46.688 long-term debt and 2.525 percent short-term debt. The Company's proposed capitalization for 2023 is composed of 50.810 percent equity, 44.587 percent long-term debt and 4.603 percent short-term debt.

Q100. Did you conduct any analysis to determine if this projected equity ratio was reasonable?

A100. Yes, I did. I reviewed the Company's proposed capital structure and the capital structures of the utility operating subsidiaries of the proxy companies. Because the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the proxy group average capital structure to benchmark the equity ratio for the Company.

Q101. Please discuss your analysis of the capital structures of the proxy group companies.

A101. I calculated the mean proportions of common equity, long-term debt and short-term debt for the most recent eight quarters[74] for each of the companies in the proxy group at the operating subsidiary level. My analysis of the capital structures of the proxy group companies is provided in Exhibit No. ___(AEB-2), Schedule 11. As shown in Exhibit No. ___(AEB-2), Schedule 11, the equity ratios for the proxy group ranged from 46.83 percent to 59.91 percent, with an average of 52.35 percent. Montana-Dakota's proposed equity ratios of 50.787 percent in 2022 and 50.810 percent in 2023 are below the average equity ratio for the utility operating subsidiaries of the proxy group and are therefore reasonable.

Q102. Are there other factors to be considered in setting the Company's capital structure?

A102. The credit rating agencies' response to the Tax Cuts and Jobs Act of 2017 ("TCJA") must also be considered when determining the equity ratio. All three rating agencies have noted that the TCJA has negative implications for utility cash flows. S&P and Fitch specifically identified increasing the equity ratio as one approach to ensure that utilities have sufficient cash flows following the federal income tax rate reductions and the loss of bonus depreciation. As S&P noted "[r]egulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact".[75] Furthermore, Moody's downgraded the rating outlook for the entire utilities sector in June 2018 and has continued to

[74] The source data for this analysis is the operating company data provided in FERC Form 1 reports. Due to the timing of those filings, my average capital structure analysis uses the quarterly capital structures reported for the proxy group companies for the period from fourth quarter of 2019 through the third quarter of 2021.

[75] Standard & Poor's Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound", January 24, 2018, at 5.

downgrade the ratings of utilities based in part on the negative effects of the TCJA on cash flows.

S&P continues to maintain a negative outlook for the utility industry in 2022 and noted that since downgrades outpaced upgrades for a second consecutive year in 2021 for the first time ever the median investor-owned utility credit rating fell to the "BBB" category.[76] Further, S&P expects continued pressure on cash flows over the near-term as utilities continue to increase leverage to fund capital expenditure plans necessary to reduce greenhouse gas emission and improve safety and reliability. Finally, S&P also highlighted inflation, higher interest rates and rising commodity prices as additional risks that could further constrain the credit metrics for utilities over the near-term. In regards to inflation S&P noted:

> Inflation recently spiked to its highest level in decades after rising for several consecutive months in 2021. Given the sustained increase to the U.S. consumer price index in 2021, inflation no longer appears to be just transitory and may have financial implications for the investor-owned North American regulated utility industry. Because of the regulatory lag within the industry, inflation, which causes prices to rise, typically leads to a weakening of financial performance. The regulatory lag is the timing difference between when costs are incurred and when regulators allow those costs to be fully recovered from ratepayers.[77]

The credit ratings agencies continued concerns over the negative effects or the TCJA, inflation, and increased capital expenditures underscores the importance of maintaining adequate cash flow metrics for the industry, as a whole, and Montana-Dakota, particularly, in the context of this proceeding.

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[76] S&P Global Ratings, "For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category," January 20, 2022.

[77] Ibid.

Q103. Is there a relationship between the equity ratio and the authorized ROE?

A103. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. 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.

Q104. What is your conclusion regarding an appropriate equity ratio for Montana-Dakota?

A104. Considering the actual capital structures of the proxy group operating companies, I believe that Montana-Dakota's proposed common equity ratios of 50.787 percent for 2022 and 50.810 percent for 2023 are reasonable. These projected equity ratios are well within the range of equity ratios established by the capital structures of the utility operating subsidiaries of the proxy companies. Finally, based on the cash flow concerns raised by credit rating agencies as a result of the TCJA, inflation, and increased capital expenditures, it is reasonable to rely on a higher equity ratio than the Company may have relied on in prior rate cases.

IX. CONCLUSION AND RECOMMENDATION

Q105. What is your conclusion regarding a fair ROE for Montana-Dakota?

A105. Figure 18 below provides a summary of my analytical results for the proxy group. Based on these results, the qualitative analyses presented in my Direct Testimony, the business and financial risks of Montana-Dakota compared to the proxy group, and current conditions in capital markets including the expectation for rising interest rates and increase in inflationary pressure, it is my view that an ROE of 10.50 percent is reasonable and would fairly balance the interests of customers and shareholders. This ROE would enable the

Company to maintain its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable, and affordable electric utility service to customers in North Dakota.

Figure 18: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.33%	9.34%	10.25%
90-Day Average	8.36%	9.37%	10.28%
180-Day Average	8.41%	9.42%	10.33%
	Median Low	Median	Median High
30-Day Average	7.98%	9.50%	10.18%
90-Day Average	8.02%	9.40%	10.21%
180-Day Average	8.15%	9.56%	10.24%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.51%	11.60%	11.63%
Bloomberg Beta	10.71%	10.85%	10.90%
Long-Term Avg. Beta	10.04%	10.24%	10.31%
ECAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.80%	11.87%	11.89%
Bloomberg Beta	11.20%	11.31%	11.35%
Long-Term Avg. Beta	10.70%	10.85%	10.90%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.68%	10.00%	10.13%
ROE Recommendation			
Range of Reasonableness		9.90%	10.75%
Recommendation		10.50%	

Q106. What is your conclusion regarding the Company's proposed common equity ratio?

A106. I conclude that Montana-Dakota's projected rate-making capital structures are reasonable when compared to the capital structures of the companies in the proxy group and taking in consideration the effect of the TCJA, and increased capital expenditures on cash flows and therefore should be adopted.

Q107. Does this conclude you direct testimony?

A107. 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 sectors, including rate of return, cost of equity, 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 several 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.

- 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.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- 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 for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- 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.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
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	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				
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				
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				
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
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	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
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
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Department of Public Service				
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
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				
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	02/22	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				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
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				
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
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	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
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	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
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 ROE ANALYSES RESULTS

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.33%	9.34%	10.25%
90-Day Average	8.36%	9.37%	10.28%
180-Day Average	8.41%	9.42%	10.33%
Constant Growth Average	8.37%	9.38%	10.29%
	Median Low	Median	Median High
30-Day Average	7.98%	9.50%	10.18%
90-Day Average	8.02%	9.40%	10.21%
180-Day Average	8.15%	9.56%	10.24%
Constant Growth Average	8.05%	9.49%	10.21%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.51%	11.60%	11.63%
Bloomberg Beta	10.71%	10.85%	10.90%
Long-term Avg. Beta	10.04%	10.24%	10.31%
ECAPM			
Value Line Beta	11.80%	11.87%	11.89%
Bloomberg Beta	11.20%	11.31%	11.35%
Long-term Avg. Beta	10.70%	10.85%	10.90%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.68%	10.00%	10.13%

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Company-Owned Generation > 40%	% Regulated Operating Income > 60%	% Regulated Electric Operating Income > 80%	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB	Yes	Yes	Yes	46.42%	95.6%	97.18%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	69.07%	96.6%	91.18%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	76.86%	100.0%	85.23%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	53.74%	95.4%	100.00%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	Yes	82.70%	99.4%	90.89%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	66.73%	100.0%	99.47%	No
Evergy, Inc.	EVRG	Yes	A-	Yes	Yes	Yes	64.10%	100.0%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	71.93%	99.8%	100.00%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	97.24%	85.1%	100.00%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	57.89%	99.7%	84.22%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	57.21%	100.0%	100.00%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	56.26%	62.7%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	62.41%	100.0%	100.00%	No
Southern Company	SO	Yes	BBB+	Yes	Yes	Yes	78.45%	84.6%	80.48%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	57.43%	100.0%	86.47%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] to [6] Source: S&P Capital IQ Pro
[7] to [8] Source: Form 10-K's for 2021, 2020, and 2019
[9] Source: S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF -- MONTANA-DAKOTA PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.60	$64.44	4.03%	4.15%	6.00%	5.67%	n/a	5.84%	9.82%	9.99%	10.16%
Alliant Energy Corporation	LNT	$1.71	$59.72	2.86%	2.94%	4.50%	6.10%	6.10%	5.57%	7.43%	8.51%	9.05%
Ameren Corporation	AEE	$2.36	$87.98	2.68%	2.78%	6.50%	7.40%	7.20%	7.03%	9.27%	9.81%	10.18%
American Electric Power Company, Inc.	AEP	$3.12	$93.63	3.33%	3.43%	6.50%	6.10%	5.80%	6.13%	9.23%	9.57%	9.94%
Duke Energy Corporation	DUK	$3.94	$104.74	3.76%	3.88%	7.00%	5.85%	6.10%	6.32%	9.72%	10.20%	10.89%
Entergy Corporation	ETR	$4.04	$109.57	3.69%	3.78%	3.00%	6.00%	6.00%	5.00%	6.74%	8.78%	9.80%
Evergy, Inc.	EVRG	$2.29	$64.00	3.58%	3.69%	7.50%	5.12%	6.10%	6.24%	8.79%	9.93%	11.21%
IDACORP, Inc.	IDA	$3.00	$108.85	2.76%	2.81%	4.00%	4.40%	4.30%	4.23%	6.81%	7.05%	7.22%
NextEra Energy, Inc.	NEE	$1.70	$80.31	2.12%	2.22%	11.00%	9.95%	8.80%	9.92%	11.01%	12.14%	13.23%
NorthWestern Corporation	NWE	$2.52	$59.44	4.24%	4.31%	2.00%	4.50%	3.10%	3.20%	6.28%	7.51%	8.84%
OGE Energy Corporation	OGE	$1.64	$38.44	4.27%	4.37%	6.50%	3.90%	3.50%	4.63%	7.84%	9.00%	10.91%
Otter Tail Corporation	OTTR	$1.65	$62.03	2.66%	2.75%	4.50%	9.00%	n/a	6.75%	7.22%	9.50%	11.78%
Portland General Electric Company	POR	$1.72	$52.99	3.25%	3.35%	7.00%	7.15%	4.60%	6.25%	7.92%	9.60%	10.51%
Southern Company	SO	$2.64	$67.65	3.90%	4.00%	5.50%	6.20%	4.00%	5.23%	7.98%	9.24%	10.22%
Xcel Energy Inc.	XEL	$1.95	$69.08	2.82%	2.91%	6.00%	6.90%	6.40%	6.43%	8.91%	9.35%	9.82%
Mean				3.33%	3.43%	5.83%	6.28%	5.54%	5.92%	8.33%	9.34%	10.25%
Median				3.33%	3.43%	6.00%	6.10%	6.00%	6.13%	7.98%	9.50%	10.18%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of March 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF -- MONTANA-DAKOTA PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.60	$63.95	4.07%	4.18%	6.00%	5.67%	n/a	5.84%	9.85%	10.02%	10.19%
Alliant Energy Corporation	LNT	$1.71	$59.27	2.89%	2.97%	4.50%	6.10%	6.10%	5.57%	7.45%	8.53%	9.07%
Ameren Corporation	AEE	$2.36	$87.24	2.71%	2.80%	6.50%	7.40%	7.20%	7.03%	9.29%	9.83%	10.21%
American Electric Power Company, Inc.	AEP	$3.12	$89.41	3.49%	3.60%	6.50%	6.10%	5.80%	6.13%	9.39%	9.73%	10.10%
Duke Energy Corporation	DUK	$3.94	$103.21	3.82%	3.94%	7.00%	5.85%	6.10%	6.32%	9.78%	10.25%	10.95%
Entergy Corporation	ETR	$4.04	$108.85	3.71%	3.80%	3.00%	6.00%	6.00%	5.00%	6.77%	8.80%	9.82%
Evergy, Inc.	EVRG	$2.29	$65.13	3.52%	3.63%	7.50%	5.12%	6.10%	6.24%	8.73%	9.87%	11.15%
IDACORP, Inc.	IDA	$3.00	$109.01	2.75%	2.81%	4.00%	4.40%	4.30%	4.23%	6.81%	7.04%	7.21%
NextEra Energy, Inc.	NEE	$1.70	$83.19	2.04%	2.14%	11.00%	9.95%	8.80%	9.92%	10.93%	12.06%	13.16%
NorthWestern Corporation	NWE	$2.52	$57.75	4.36%	4.43%	2.00%	4.50%	3.10%	3.20%	6.41%	7.63%	8.96%
OGE Energy Corporation	OGE	$1.64	$37.44	4.38%	4.48%	6.50%	3.90%	3.50%	4.63%	7.96%	9.12%	11.02%
Otter Tail Corporation	OTTR	$1.65	$64.39	2.56%	2.65%	4.50%	9.00%	n/a	6.75%	7.12%	9.40%	11.68%
Portland General Electric Company	POR	$1.72	$52.15	3.30%	3.40%	7.00%	7.15%	4.60%	6.25%	7.97%	9.65%	10.57%
Southern Company	SO	$2.64	$66.93	3.94%	4.05%	5.50%	6.20%	4.00%	5.23%	8.02%	9.28%	10.27%
Xcel Energy Inc.	XEL	$1.95	$68.03	2.87%	2.96%	6.00%	6.90%	6.40%	6.43%	8.95%	9.39%	9.87%
Mean				3.36%	3.46%	5.83%	6.28%	5.54%	5.92%	8.36%	9.37%	10.28%
Median				3.49%	3.60%	6.00%	6.10%	6.00%	6.13%	8.02%	9.40%	10.21%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of March 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF -- MONTANA-DAKOTA PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth	[6] Yahoo! Finance EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.60	$64.61	4.02%	4.14%	6.00%	5.67%	n/a	5.84%	9.81%	9.98%	10.14%
Alliant Energy Corporation	LNT	$1.71	$58.72	2.91%	2.99%	4.50%	6.10%	6.10%	5.57%	7.48%	8.56%	9.10%
Ameren Corporation	AEE	$2.36	$86.15	2.74%	2.84%	6.50%	7.40%	7.20%	7.03%	9.33%	9.87%	10.24%
American Electric Power Company, Inc.	AEP	$3.12	$87.74	3.56%	3.66%	6.50%	6.10%	5.80%	6.13%	9.46%	9.80%	10.17%
Duke Energy Corporation	DUK	$3.94	$103.02	3.82%	3.95%	7.00%	5.85%	6.10%	6.32%	9.79%	10.26%	10.96%
Entergy Corporation	ETR	$4.04	$107.44	3.76%	3.85%	3.00%	6.00%	6.00%	5.00%	6.82%	8.85%	9.87%
Evergy, Inc.	EVRG	$2.29	$65.21	3.51%	3.62%	7.50%	5.12%	6.10%	6.24%	8.72%	9.86%	11.14%
IDACORP, Inc.	IDA	$3.00	$107.01	2.80%	2.86%	4.00%	4.40%	4.30%	4.23%	6.86%	7.10%	7.27%
NextEra Energy, Inc.	NEE	$1.70	$82.83	2.05%	2.15%	11.00%	9.95%	8.80%	9.92%	10.94%	12.07%	13.17%
NorthWestern Corporation	NWE	$2.52	$59.06	4.27%	4.34%	2.00%	4.50%	3.10%	3.20%	6.31%	7.54%	8.86%
OGE Energy Corporation	OGE	$1.64	$35.92	4.57%	4.67%	6.50%	3.90%	3.50%	4.63%	8.15%	9.31%	11.21%
Otter Tail Corporation	OTTR	$1.65	$60.70	2.72%	2.81%	4.50%	9.00%	n/a	6.75%	7.28%	9.56%	11.84%
Portland General Electric Company	POR	$1.72	$50.78	3.39%	3.49%	7.00%	7.15%	4.60%	6.25%	8.07%	9.74%	10.66%
Southern Company	SO	$2.64	$65.46	4.03%	4.14%	5.50%	6.20%	4.00%	5.23%	8.11%	9.37%	10.36%
Xcel Energy Inc.	XEL	$1.95	$67.11	2.91%	3.00%	6.00%	6.90%	6.40%	6.43%	8.99%	9.43%	9.91%
Mean				3.40%	3.50%	5.83%	6.28%	5.54%	5.92%	8.41%	9.42%	10.33%
Median				3.51%	3.62%	6.00%	6.10%	6.00%	6.13%	8.15%	9.56%	10.24%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of March 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	2.37%	0.90	12.68%	10.31%	11.65%	11.91%
Alliant Energy Corporation	LNT	2.37%	0.85	12.68%	10.31%	11.13%	11.52%
Ameren Corporation	AEE	2.37%	0.80	12.68%	10.31%	10.62%	11.13%
American Electric Power Company, Inc.	AEP	2.37%	0.75	12.68%	10.31%	10.10%	10.75%
Duke Energy Corporation	DUK	2.37%	0.85	12.68%	10.31%	11.13%	11.52%
Entergy Corporation	ETR	2.37%	0.95	12.68%	10.31%	12.17%	12.29%
Evergy, Inc.	EVRG	2.37%	0.95	12.68%	10.31%	12.17%	12.29%
IDACORP, Inc.	IDA	2.37%	0.80	12.68%	10.31%	10.62%	11.13%
NextEra Energy, Inc.	NEE	2.37%	0.95	12.68%	10.31%	12.17%	12.29%
NorthWestern Corporation	NWE	2.37%	0.95	12.68%	10.31%	12.17%	12.29%
OGE Energy Corporation	OGE	2.37%	1.05	12.68%	10.31%	13.20%	13.07%
Otter Tail Corporation	OTTR	2.37%	0.85	12.68%	10.31%	11.13%	11.52%
Portland General Electric Company	POR	2.37%	0.90	12.68%	10.31%	11.65%	11.91%
Southern Company	SO	2.37%	0.95	12.68%	10.31%	12.17%	12.29%
Xcel Energy Inc.	XEL	2.37%	0.80	12.68%	10.31%	10.62%	11.13%
Mean						11.51%	11.80%
Median						11.65%	11.91%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2022
[2] Source: Value Line
[3] Source: Schedule 7
[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 & VL BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q3 2022 - Q3 2023)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.12%	0.90	12.68%	9.56%	11.73%	11.96%
Alliant Energy Corporation	LNT	3.12%	0.85	12.68%	9.56%	11.25%	11.61%
Ameren Corporation	AEE	3.12%	0.80	12.68%	9.56%	10.77%	11.25%
American Electric Power Company, Inc.	AEP	3.12%	0.75	12.68%	9.56%	10.29%	10.89%
Duke Energy Corporation	DUK	3.12%	0.85	12.68%	9.56%	11.25%	11.61%
Entergy Corporation	ETR	3.12%	0.95	12.68%	9.56%	12.20%	12.32%
Evergy, Inc.	EVRG	3.12%	0.95	12.68%	9.56%	12.20%	12.32%
IDACORP, Inc.	IDA	3.12%	0.80	12.68%	9.56%	10.77%	11.25%
NextEra Energy, Inc.	NEE	3.12%	0.95	12.68%	9.56%	12.20%	12.32%
NorthWestern Corporation	NWE	3.12%	0.95	12.68%	9.56%	12.20%	12.32%
OGE Energy Corporation	OGE	3.12%	1.05	12.68%	9.56%	13.16%	13.04%
Otter Tail Corporation	OTTR	3.12%	0.85	12.68%	9.56%	11.25%	11.61%
Portland General Electric Company	POR	3.12%	0.90	12.68%	9.56%	11.73%	11.96%
Southern Company	SO	3.12%	0.95	12.68%	9.56%	12.20%	12.32%
Xcel Energy Inc.	XEL	3.12%	0.80	12.68%	9.56%	10.77%	11.25%
Mean						11.60%	11.87%
Median						11.73%	11.96%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2
[2] Source: Value Line
[3] Source: Schedule 7
[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 & VL 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 (2023 - 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.90	12.68%	9.28%	11.75%	11.99%
Alliant Energy Corporation	LNT	3.40%	0.85	12.68%	9.28%	11.29%	11.64%
Ameren Corporation	AEE	3.40%	0.80	12.68%	9.28%	10.82%	11.29%
American Electric Power Company, Inc.	AEP	3.40%	0.75	12.68%	9.28%	10.36%	10.94%
Duke Energy Corporation	DUK	3.40%	0.85	12.68%	9.28%	11.29%	11.64%
Entergy Corporation	ETR	3.40%	0.95	12.68%	9.28%	12.22%	12.33%
Evergy, Inc.	EVRG	3.40%	0.95	12.68%	9.28%	12.22%	12.33%
IDACORP, Inc.	IDA	3.40%	0.80	12.68%	9.28%	10.82%	11.29%
NextEra Energy, Inc.	NEE	3.40%	0.95	12.68%	9.28%	12.22%	12.33%
NorthWestern Corporation	NWE	3.40%	0.95	12.68%	9.28%	12.22%	12.33%
OGE Energy Corporation	OGE	3.40%	1.05	12.68%	9.28%	13.15%	13.03%
Otter Tail Corporation	OTTR	3.40%	0.85	12.68%	9.28%	11.29%	11.64%
Portland General Electric Company	POR	3.40%	0.90	12.68%	9.28%	11.75%	11.99%
Southern Company	SO	3.40%	0.95	12.68%	9.28%	12.22%	12.33%
Xcel Energy Inc.	XEL	3.40%	0.80	12.68%	9.28%	10.82%	11.29%
Mean						11.63%	11.89%
Median						11.75%	11.99%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: Value Line
[3] Source: Schedule 7
[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 & 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)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.37%	0.83	12.68%	10.31%	10.97%	11.40%
Alliant Energy Corporation	LNT	2.37%	0.79	12.68%	10.31%	10.54%	11.07%
Ameren Corporation	AEE	2.37%	0.75	12.68%	10.31%	10.12%	10.76%
American Electric Power Company, Inc.	AEP	2.37%	0.77	12.68%	10.31%	10.27%	10.87%
Duke Energy Corporation	DUK	2.37%	0.71	12.68%	10.31%	9.72%	10.46%
Entergy Corporation	ETR	2.37%	0.86	12.68%	10.31%	11.25%	11.61%
Evergy, Inc.	EVRG	2.37%	0.80	12.68%	10.31%	10.60%	11.12%
IDACORP, Inc.	IDA	2.37%	0.82	12.68%	10.31%	10.82%	11.29%
NextEra Energy, Inc.	NEE	2.37%	0.78	12.68%	10.31%	10.44%	11.00%
NorthWestern Corporation	NWE	2.37%	0.89	12.68%	10.31%	11.57%	11.85%
OGE Energy Corporation	OGE	2.37%	0.93	12.68%	10.31%	11.93%	12.12%
Otter Tail Corporation	OTTR	2.37%	0.87	12.68%	10.31%	11.38%	11.71%
Portland General Electric Company	POR	2.37%	0.80	12.68%	10.31%	10.64%	11.15%
Southern Company	SO	2.37%	0.78	12.68%	10.31%	10.40%	10.97%
Xcel Energy Inc.	XEL	2.37%	0.73	12.68%	10.31%	9.95%	10.63%
Mean						10.71%	11.20%
Median						10.60%	11.12%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2022
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of March 31, 2022
[3] Source: Schedule 7
[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 & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q3 2022 - Q3 2023)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.12%	0.83	12.68%	9.56%	11.09%	11.49%
Alliant Energy Corporation	LNT	3.12%	0.79	12.68%	9.56%	10.69%	11.19%
Ameren Corporation	AEE	3.12%	0.75	12.68%	9.56%	10.31%	10.90%
American Electric Power Company, Inc.	AEP	3.12%	0.77	12.68%	9.56%	10.45%	11.00%
Duke Energy Corporation	DUK	3.12%	0.71	12.68%	9.56%	9.94%	10.62%
Entergy Corporation	ETR	3.12%	0.86	12.68%	9.56%	11.36%	11.69%
Evergy, Inc.	EVRG	3.12%	0.80	12.68%	9.56%	10.75%	11.23%
IDACORP, Inc.	IDA	3.12%	0.82	12.68%	9.56%	10.96%	11.39%
NextEra Energy, Inc.	NEE	3.12%	0.78	12.68%	9.56%	10.60%	11.12%
NorthWestern Corporation	NWE	3.12%	0.89	12.68%	9.56%	11.65%	11.91%
OGE Energy Corporation	OGE	3.12%	0.93	12.68%	9.56%	11.99%	12.16%
Otter Tail Corporation	OTTR	3.12%	0.87	12.68%	9.56%	11.48%	11.78%
Portland General Electric Company	POR	3.12%	0.80	12.68%	9.56%	10.79%	11.26%
Southern Company	SO	3.12%	0.78	12.68%	9.56%	10.57%	11.10%
Xcel Energy Inc.	XEL	3.12%	0.73	12.68%	9.56%	10.15%	10.78%
Mean						10.85%	11.31%
Median						10.75%	11.23%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of March 31, 2022
[3] Source: Schedule 7
[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 & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2023 - 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.83	12.68%	9.28%	11.14%	11.53%
Alliant Energy Corporation	LNT	3.40%	0.79	12.68%	9.28%	10.75%	11.23%
Ameren Corporation	AEE	3.40%	0.75	12.68%	9.28%	10.38%	10.95%
American Electric Power Company, Inc.	AEP	3.40%	0.77	12.68%	9.28%	10.51%	11.05%
Duke Energy Corporation	DUK	3.40%	0.71	12.68%	9.28%	10.02%	10.68%
Entergy Corporation	ETR	3.40%	0.86	12.68%	9.28%	11.40%	11.72%
Evergy, Inc.	EVRG	3.40%	0.80	12.68%	9.28%	10.80%	11.27%
IDACORP, Inc.	IDA	3.40%	0.82	12.68%	9.28%	11.01%	11.43%
NextEra Energy, Inc.	NEE	3.40%	0.78	12.68%	9.28%	10.66%	11.17%
NorthWestern Corporation	NWE	3.40%	0.89	12.68%	9.28%	11.68%	11.93%
OGE Energy Corporation	OGE	3.40%	0.93	12.68%	9.28%	12.01%	12.18%
Otter Tail Corporation	OTTR	3.40%	0.87	12.68%	9.28%	11.51%	11.80%
Portland General Electric Company	POR	3.40%	0.80	12.68%	9.28%	10.84%	11.30%
Southern Company	SO	3.40%	0.78	12.68%	9.28%	10.63%	11.14%
Xcel Energy Inc.	XEL	3.40%	0.73	12.68%	9.28%	10.22%	10.84%
Mean						10.90%	11.35%
Median						10.80%	11.27%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of March 31, 2022
[3] Source: Schedule 7
[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 & VALUE LINE LT AVERAGE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	2.37%	0.77	12.68%	10.31%	10.33%	10.92%
Alliant Energy Corporation	LNT	2.37%	0.74	12.68%	10.31%	9.99%	10.66%
Ameren Corporation	AEE	2.37%	0.71	12.68%	10.31%	9.70%	10.45%
American Electric Power Company, Inc.	AEP	2.37%	0.67	12.68%	10.31%	9.24%	10.10%
Duke Energy Corporation	DUK	2.37%	0.64	12.68%	10.31%	9.02%	9.93%
Entergy Corporation	ETR	2.37%	0.72	12.68%	10.31%	9.82%	10.53%
Evergy, Inc.	EVRG	2.37%	0.98	12.68%	10.31%	12.42%	12.49%
IDACORP, Inc.	IDA	2.37%	0.72	12.68%	10.31%	9.82%	10.53%
NextEra Energy, Inc.	NEE	2.37%	0.71	12.68%	10.31%	9.65%	10.40%
NorthWestern Corporation	NWE	2.37%	0.73	12.68%	10.31%	9.87%	10.58%
OGE Energy Corporation	OGE	2.37%	0.92	12.68%	10.31%	11.88%	12.08%
Otter Tail Corporation	OTTR	2.37%	0.85	12.68%	10.31%	11.13%	11.52%
Portland General Electric Company	POR	2.37%	0.74	12.68%	10.31%	9.99%	10.66%
Southern Company	SO	2.37%	0.63	12.68%	10.31%	8.84%	9.80%
Xcel Energy Inc.	XEL	2.37%	0.64	12.68%	10.31%	8.96%	9.89%
Mean						10.04%	10.70%
Median						9.82%	10.53%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2022
[2] Source: Schedule 6
[3] Source: Schedule 7
[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 & VALUE LINE LT AVERAGE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q3 2022 - Q3 2023)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.12%	0.77	12.68%	9.56%	10.50%	11.05%
Alliant Energy Corporation	LNT	3.12%	0.74	12.68%	9.56%	10.18%	10.81%
Ameren Corporation	AEE	3.12%	0.71	12.68%	9.56%	9.92%	10.61%
American Electric Power Company, Inc.	AEP	3.12%	0.67	12.68%	9.56%	9.49%	10.29%
Duke Energy Corporation	DUK	3.12%	0.64	12.68%	9.56%	9.28%	10.13%
Entergy Corporation	ETR	3.12%	0.72	12.68%	9.56%	10.03%	10.69%
Evergy, Inc.	EVRG	3.12%	0.98	12.68%	9.56%	12.44%	12.50%
IDACORP, Inc.	IDA	3.12%	0.72	12.68%	9.56%	10.03%	10.69%
NextEra Energy, Inc.	NEE	3.12%	0.71	12.68%	9.56%	9.87%	10.57%
NorthWestern Corporation	NWE	3.12%	0.73	12.68%	9.56%	10.08%	10.73%
OGE Energy Corporation	OGE	3.12%	0.92	12.68%	9.56%	11.94%	12.12%
Otter Tail Corporation	OTTR	3.12%	0.85	12.68%	9.56%	11.25%	11.61%
Portland General Electric Company	POR	3.12%	0.74	12.68%	9.56%	10.18%	10.81%
Southern Company	SO	3.12%	0.63	12.68%	9.56%	9.12%	10.01%
Xcel Energy Inc.	XEL	3.12%	0.64	12.68%	9.56%	9.23%	10.09%
Mean						10.24%	10.85%
Median						10.03%	10.69%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2
[2] Source: Schedule 6
[3] Source: Schedule 7
[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 & VALUE LINE LT BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2023 - 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.77	12.68%	9.28%	10.57%	11.10%
Alliant Energy Corporation	LNT	3.40%	0.74	12.68%	9.28%	10.26%	10.86%
Ameren Corporation	AEE	3.40%	0.71	12.68%	9.28%	10.00%	10.67%
American Electric Power Company, Inc.	AEP	3.40%	0.67	12.68%	9.28%	9.59%	10.36%
Duke Energy Corporation	DUK	3.40%	0.64	12.68%	9.28%	9.38%	10.21%
Entergy Corporation	ETR	3.40%	0.72	12.68%	9.28%	10.10%	10.75%
Evergy, Inc.	EVRG	3.40%	0.98	12.68%	9.28%	12.45%	12.51%
IDACORP, Inc.	IDA	3.40%	0.72	12.68%	9.28%	10.10%	10.75%
NextEra Energy, Inc.	NEE	3.40%	0.71	12.68%	9.28%	9.95%	10.63%
NorthWestern Corporation	NWE	3.40%	0.73	12.68%	9.28%	10.15%	10.79%
OGE Energy Corporation	OGE	3.40%	0.92	12.68%	9.28%	11.96%	12.14%
Otter Tail Corporation	OTTR	3.40%	0.85	12.68%	9.28%	11.29%	11.64%
Portland General Electric Company	POR	3.40%	0.74	12.68%	9.28%	10.26%	10.86%
Southern Company	SO	3.40%	0.63	12.68%	9.28%	9.23%	10.09%
Xcel Energy Inc.	XEL	3.40%	0.64	12.68%	9.28%	9.33%	10.17%
Mean						10.31%	10.90%
Median						10.10%	10.75%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: Schedule 6
[3] Source: Schedule 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA - 2013 - 2021

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
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	Average
ALLETE, Inc.	ALE	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.77
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.74
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.71
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.67
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.64
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.72
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.98
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.72
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.71
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.73
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	0.92
Otter Tail Corporation	OTTR	0.95	0.90	0.85	0.85	0.90	0.75	0.70	0.85	0.90	0.85
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.74
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.63
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.64
Mean		0.73	0.74	0.75	0.69	0.70	0.59	0.58	0.88	0.89	0.74

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] Average ([1] - [9])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.61%
[2] Estimated Weighted Average Long-Term Growth Rate	10.99%
[3] S&P 500 Estimated Required Market Return	12.68%

STANDARD AND POOR'S 500 INDEX

		[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	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Agilent Technologies Inc	A	300.11	132.33	39,713.95	0.14%	0.63%	0.00%	11.50%	0.02%
American Airlines Group Inc	AAL	649.16	18.25	11,847.17					
Advance Auto Parts Inc	AAP	61.10	206.96	12,644.84	0.04%	2.90%	0.00%	11.00%	0.00%
Apple Inc	AAPL	16,319.44	174.61	2,849,537.59	9.70%	0.50%	0.05%	14.00%	1.36%
AbbVie Inc	ABBV	1,766.29	162.11	286,332.46	0.97%	3.48%	0.03%	4.50%	0.04%
AmerisourceBergen Corp	ABC	209.14	154.71	32,355.59	0.11%	1.19%	0.00%	6.50%	0.01%
ABIOMED Inc	ABMD	45.52	331.24	15,076.72	0.05%			7.50%	0.00%
Abbott Laboratories	ABT	1,763.48	118.36	208,725.73	0.71%	1.59%	0.01%	10.00%	0.07%
Accenture PLC	ACN	662.43	337.23	223,392.62	0.76%	1.15%	0.01%	12.00%	0.09%
Adobe Inc	ADBE	472.50	455.62	215,280.45	0.73%			15.50%	0.11%
Analog Devices Inc	ADI	523.32	165.18	86,441.17	0.29%	1.84%	0.01%	11.00%	0.03%
Archer-Daniels-Midland Co	ADM	562.48	90.26	50,769.17	0.17%	1.77%	0.00%	12.50%	0.02%
Automatic Data Processing Inc	ADP	420.05	227.54	95,577.04	0.33%	1.83%	0.01%	9.00%	0.03%
Autodesk Inc	ADSK	217.31	214.35	46,579.97	0.16%			18.00%	0.03%
Ameren Corp	AEE	258.09	93.76	24,198.71	0.08%	2.52%	0.00%	6.50%	0.01%
American Electric Power Co Inc	AEP	504.55	99.77	50,338.65	0.17%	3.13%	0.01%	6.50%	0.01%
AES Corp/The	AES	667.40	25.73	17,172.07	0.06%	2.46%	0.00%	14.00%	0.01%
Aflac Inc	AFL	649.37	64.39	41,812.81	0.14%	2.48%	0.00%	9.00%	0.01%
American International Group Inc	AIG	806.25	62.77	50,608.19		2.04%		31.50%	
Assurant Inc	AIZ	57.71	181.83	10,493.05	0.04%	1.50%	0.00%	15.50%	0.01%
Arthur J Gallagher & Co	AJG	209.61	174.60	36,598.60	0.12%	1.17%	0.00%	14.50%	0.02%
Akamai Technologies Inc	AKAM	160.90	119.39	19,209.73	0.07%			9.50%	0.01%
Albemarle Corp	ALB	117.11	221.15	25,899.32	0.09%	0.71%	0.00%	6.50%	0.01%
Align Technology Inc	ALGN	78.80	436.00	34,354.62	0.12%			17.00%	0.02%
Alaska Air Group Inc	ALK	126.09	58.01	7,314.31					
Allstate Corp/The	ALL	278.35	138.51	38,553.70	0.13%	2.45%	0.00%	5.00%	0.01%
Allegion plc	ALLE	88.23	109.78	9,685.89	0.03%	1.49%	0.00%	10.50%	0.00%
Applied Materials Inc	AMAT	883.40	131.80	116,431.46	0.40%	0.79%	0.00%	14.50%	0.06%
Amcor PLC	AMCR	1,513.73	11.33	17,150.53	0.06%	4.24%	0.00%	15.00%	0.01%
Advanced Micro Devices Inc	AMD	1,627.37	109.34	177,936.09	0.61%			17.50%	0.11%
AMETEK Inc	AME	231.17	133.18	30,787.35	0.10%	0.66%	0.00%	9.00%	0.01%
Amgen Inc	AMGN	557.03	241.82	134,700.75	0.46%	3.21%	0.01%	5.50%	0.03%
Ameriprise Financial Inc	AMP	110.58	300.36	33,212.91	0.11%	1.50%	0.00%	13.50%	0.02%
American Tower Corp	AMT	455.89	251.22	114,527.43	0.39%	2.23%	0.01%	9.00%	0.04%
Amazon.com Inc	AMZN	508.84	3,259.95	1,658,806.00				26.50%	
Arista Networks Inc	ANET	307.77	138.98	42,773.46	0.15%			4.50%	0.01%
ANSYS Inc	ANSS	87.03	317.65	27,643.81	0.09%			8.50%	0.01%
Anthem Inc	ANTM	241.30	491.22	118,533.35	0.40%	1.04%	0.00%	12.50%	0.05%
Aon PLC	AON	213.94	325.63	69,666.58	0.24%	0.63%	0.00%	7.00%	0.02%
A O Smith Corp	AOS	131.05	63.89	8,372.72	0.03%	1.75%	0.00%	10.00%	0.00%
APA Corp	APA	346.78	41.33	14,332.25		1.21%			
Air Products and Chemicals Inc	APD	221.72	249.91	55,409.30	0.19%	2.59%	0.00%	12.00%	0.02%
Amphenol Corp	APH	598.94	75.35	45,130.13	0.15%	1.06%	0.00%	12.00%	0.02%
Aptiv PLC	APTV	270.92	119.71	32,431.23				21.50%	
Alexandria Real Estate Equities Inc	ARE	159.94	201.25	32,188.53	0.11%	2.29%	0.00%	9.00%	0.01%
Atmos Energy Corp	ATO	135.43	119.49	16,182.77	0.06%	2.28%	0.00%	7.50%	0.00%
Activision Blizzard Inc	ATVI	780.92	80.11	62,559.74	0.21%	0.59%	0.00%	15.00%	0.03%
AvalonBay Communities Inc	AVB	139.75	248.37	34,710.20	0.12%	2.56%	0.00%	6.50%	0.01%
Broadcom Inc	AVGO	408.28	629.68	257,086.38		2.60%		23.00%	
Avery Dennison Corp	AVY	82.36	173.97	14,327.30	0.05%	1.56%	0.00%	9.00%	0.00%
American Water Works Co Inc	AWK	181.75	165.53	30,085.57	0.10%	1.46%	0.00%	8.50%	0.01%
American Express Co	AXP	757.29	187.00	141,613.04	0.48%	1.11%	0.01%	12.00%	0.06%
AutoZone Inc	AZO	19.85	2,044.58	40,582.87	0.14%			16.50%	0.02%
Boeing Co/The	BA	590.39	191.50	113,058.73					
Bank of America Corp	BAC	8,064.86	41.22	332,433.32	1.13%	2.04%	0.02%	7.50%	0.08%
Baxter International Inc	BAX	503.20	77.54	39,017.90	0.13%	1.44%	0.00%	9.50%	0.01%
Bath & Body Works Inc	BBWI	238.91	47.80	11,419.90		1.67%		26.00%	
Best Buy Co Inc	BBY	225.23	90.90	20,473.23	0.07%	3.87%	0.00%	8.50%	0.01%
Becton Dickinson and Co	BDX	284.77	259.33	73,850.80	0.25%	1.34%	0.00%	6.00%	0.02%
Franklin Resources Inc	BEN	502.12	27.92	14,019.30	0.05%	4.15%	0.00%	11.00%	0.01%
Brown-Forman Corp	BF/B	309.80	67.02	20,762.46	0.07%	1.13%	0.00%	13.00%	0.01%
Biogen Inc	BIIB	146.96	210.60	30,950.41				-10.50%	
Bio-Rad Laboratories Inc	BIO	24.86	563.23	14,003.59	0.05%			9.50%	0.00%
Bank of New York Mellon Corp/The	BK	807.11	49.63	40,056.67	0.14%	2.74%	0.00%	5.00%	0.01%
Booking Holdings Inc	BKNG	40.89	2,348.45	96,023.42	0.33%			14.00%	0.05%
Baker Hughes Co	BKR	953.34	36.41	34,711.15		1.98%			
BlackRock Inc	BLK	152.04	764.17	116,185.94	0.40%	2.55%	0.01%	11.00%	0.04%
Ball Corp	BLL	321.21	90.00	28,909.08		0.89%		21.00%	
Bristol-Myers Squibb Co	BMY	2,125.20	73.03	155,203.58		2.96%			
Broadridge Financial Solutions Inc	BR	116.77	155.71	18,182.72	0.06%	1.64%	0.00%	9.00%	0.01%
Berkshire Hathaway Inc	BRK/B	1,287.63	352.91	454,418.91	1.55%			6.00%	0.09%
Brown & Brown Inc	BRO	282.22	72.27	20,395.75	0.07%	0.57%	0.00%	10.50%	0.01%
Boston Scientific Corp	BSX	1,429.45	44.29	63,310.21	0.22%			16.00%	0.03%
BorgWarner Inc	BWA	239.97	38.90	9,334.95	0.03%	1.75%	0.00%	9.50%	0.00%
Boston Properties Inc	BXP	156.68	128.80	20,179.87		3.04%		-1.50%	
Citigroup Inc	C	1,972.47	53.40	105,330.11	0.36%	3.82%	0.01%	7.00%	0.03%
Conagra Brands Inc	CAG	479.70	33.57	16,103.46	0.05%	3.72%	0.00%	4.50%	0.00%
Cardinal Health Inc	CAH	277.06	56.70	15,709.36	0.05%	3.46%	0.00%	5.00%	0.00%
Carrier Global Corp	CARR	853.01	45.87	39,127.43		1.31%			
Caterpillar Inc	CAT	535.89	222.82	119,406.56	0.41%	1.99%	0.01%	8.00%	0.03%

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Chubb Ltd	CB	426.23	213.90	91,170.38	0.31%	1.50%	0.00%	12.50%	0.04%
Cboe Global Markets Inc	CBOE	106.60	114.42	12,197.40	0.04%	1.68%	0.00%	12.00%	0.00%
CBRE Group Inc	CBRE	332.32	91.52	30,414.20	0.10%			10.00%	0.01%
Crown Castle International Corp	CCI	433.03	184.60	79,937.34	0.27%	3.19%	0.01%	12.00%	0.03%
Carnival Corp	CCL	989.70	20.22	20,011.75					
Ceridian HCM Holding Inc	CDAY	150.11	68.36	10,261.45					
Cadence Design Systems Inc	CDNS	278.38	164.46	45,781.72	0.16%			12.00%	0.02%
CDW Corp/DE	CDW	134.94	178.89	24,140.13	0.08%	1.12%	0.00%	11.00%	0.01%
Celanese Corp	CE	108.03	142.87	15,434.10	0.05%	1.90%	0.00%	6.50%	0.00%
Constellation Energy Corp	CEG	326.66	56.25	18,374.85		1.00%			
Cerner Corp	CERN	293.85	93.56	27,492.23	0.09%	1.15%	0.00%	9.50%	0.01%
CF Industries Holdings Inc	CF	209.11	103.06	21,551.29	0.07%	1.16%	0.00%	19.50%	0.01%
Citizens Financial Group Inc	CFG	422.14	45.33	19,135.74	0.07%	3.44%	0.00%	8.50%	0.01%
Church & Dwight Co Inc	CHD	242.70	99.38	24,119.13	0.08%	1.06%	0.00%	8.00%	0.01%
CH Robinson Worldwide Inc	CHRW	128.64	107.71	13,855.81	0.05%	2.04%	0.00%	9.00%	0.00%
Charter Communications Inc	CHTR	191.49	545.52	104,463.26				21.50%	
Cigna Corp	CI	320.95	239.61	76,903.55	0.26%	1.87%	0.00%	10.00%	0.03%
Cincinnati Financial Corp	CINF	160.44	135.96	21,813.29	0.07%	2.03%	0.00%	15.00%	0.01%
Colgate-Palmolive Co	CL	840.59	75.83	63,742.17	0.22%	2.48%	0.01%	5.00%	0.01%
Clorox Co/The	CLX	123.06	139.03	17,108.75	0.06%	3.34%	0.00%	5.00%	0.00%
Comerica Inc	CMA	131.09	90.43	11,854.38	0.04%	3.01%	0.00%	6.00%	0.00%
Comcast Corp	CMCSA	4,523.79	46.82	211,803.66	0.72%	2.31%	0.02%	10.50%	0.08%
CME Group Inc	CME	359.42	237.86	85,491.40	0.29%	1.68%	0.00%	8.50%	0.02%
Chipotle Mexican Grill Inc	CMG	28.03	1,582.03	44,347.46	0.15%			20.00%	0.03%
Cummins Inc	CMI	142.08	205.11	29,141.00	0.10%	2.83%	0.00%	8.00%	0.01%
CMS Energy Corp	CMS	290.14	69.94	20,292.18	0.07%	2.63%	0.00%	6.50%	0.00%
Centene Corp	CNC	582.88	84.19	49,072.25	0.17%			10.00%	0.02%
CenterPoint Energy Inc	CNP	629.43	30.64	19,285.80	0.07%	2.22%	0.00%	5.00%	0.00%
Capital One Financial Corp	COF	405.67	131.29	53,260.41		1.83%			
Cooper Cos Inc/The	COO	49.30	417.59	20,588.02	0.07%	0.01%	0.00%	19.00%	0.01%
ConocoPhillips	COP	1,296.05	100.00	129,605.10	0.44%	1.84%	0.01%	16.50%	0.07%
Costco Wholesale Corp	COST	443.22	575.85	255,230.54	0.87%	0.55%	0.00%	10.50%	0.09%
Campbell Soup Co	CPB	301.70	44.57	13,446.95	0.05%	3.32%	0.00%	5.50%	0.00%
Copart Inc	CPRT	237.50	125.47	29,798.75	0.10%			12.00%	0.01%
Charles River Laboratories International Inc	CRL	50.80	283.97	14,425.39	0.05%			6.50%	0.00%
salesforce.com Inc	CRM	990.00	212.32	210,196.80	0.72%			20.00%	0.14%
Cisco Systems Inc	CSCO	4,154.17	55.76	231,636.41	0.79%	2.73%	0.02%	8.00%	0.06%
CSX Corp	CSX	2,178.58	37.45	81,587.82	0.28%	1.07%	0.00%	10.00%	0.03%
Cintas Corp	CTAS	102.42	425.39	43,566.74	0.15%	0.89%	0.00%	13.50%	0.02%
Catalent Inc	CTLT	179.13	110.90	19,865.30				21.00%	
Coterra Energy Inc	CTRA	810.98	26.97	21,872.10		8.31%			
Cognizant Technology Solutions Corp	CTSH	524.54	89.67	47,035.05	0.16%	1.20%	0.00%	7.00%	0.01%
Corteva Inc	CTVA	726.77	57.48	41,774.97		0.97%			
Citrix Systems Inc	CTXS	125.91	100.90	12,704.62	0.04%			8.00%	0.00%
CVS Health Corp	CVS	1,312.51	101.21	132,839.14	0.45%	2.17%	0.01%	6.00%	0.03%
Chevron Corp	CVX	1,947.55	162.83	317,120.05		3.49%		25.00%	
Caesars Entertainment Inc	CZR	214.12	77.36	16,564.56					
Dominion Energy Inc	D	810.67	84.97	68,882.97	0.23%	3.14%	0.01%	11.50%	0.03%
Delta Air Lines Inc	DAL	639.93	39.57	25,322.03				49.00%	
DuPont de Nemours Inc	DD	512.91	73.58	37,739.70		1.79%			
Deere & Co	DE	306.78	415.46	127,456.48		1.01%		21.50%	
Discover Financial Services	DFS	282.03	110.19	31,076.67	0.11%	1.82%	0.00%	16.00%	0.02%
Dollar General Corp	DG	228.87	222.63	50,952.88	0.17%	0.99%	0.00%	10.50%	0.02%
Quest Diagnostics Inc	DGX	119.46	136.86	16,348.61	0.06%	1.93%	0.00%	7.50%	0.00%
DR Horton Inc	DHI	354.36	74.51	26,403.21	0.09%	1.21%	0.00%	11.00%	0.01%
Danaher Corp	DHR	715.90	293.33	209,993.48		0.34%		21.00%	
Walt Disney Co/The	DIS	1,820.63	137.16	249,718.02				37.50%	
Discovery Inc	DISCA	171.54	24.92	4,274.85	0.01%			13.50%	0.00%
Discovery Inc	DISCK	330.15	24.97	8,243.95					
DISH Network Corp	DISH	290.57	31.65	9,196.60	0.03%			2.00%	0.00%
Digital Realty Trust Inc	DLR	284.47	141.80	40,337.70		3.44%		-3.50%	
Dollar Tree Inc	DLTR	225.11	160.15	36,051.37	0.12%			10.00%	0.01%
Dover Corp	DOV	144.11	156.90	22,610.23	0.08%	1.27%	0.00%	9.00%	0.01%
Dow Inc	DOW	735.09	63.72	46,839.68		4.39%			
Domino's Pizza Inc	DPZ	36.03	407.01	14,665.79	0.05%	1.08%	0.00%	16.50%	0.01%
Duke Realty Corp	DRE	382.77	58.06	22,223.51	0.08%	1.93%	0.00%	2.50%	0.00%
Darden Restaurants Inc	DRI	127.72	132.95	16,980.91	0.06%	3.31%	0.00%	15.50%	0.01%
DTE Energy Co	DTE	193.74	132.21	25,614.63	0.09%	2.68%	0.00%	4.50%	0.00%
Duke Energy Corp	DUK	769.90	111.66	85,966.92	0.29%	3.53%	0.01%	7.00%	0.02%
DaVita Inc	DVA	96.30	113.11	10,892.49	0.04%			16.00%	0.01%
Devon Energy Corp	DVN	664.20	59.13	39,274.15		6.76%		29.50%	
DXC Technology Co	DXC	244.48	32.63	7,977.32	0.03%			6.00%	0.00%
Dexcom Inc	DXCM	97.39	511.60	49,824.72				34.00%	
Electronic Arts Inc	EA	281.22	126.51	35,577.40	0.12%	0.54%	0.00%	10.50%	0.01%
eBay Inc	EBAY	587.53	57.26	33,641.91	0.11%	1.54%	0.00%	16.50%	0.02%
Ecolab Inc	ECL	286.30	176.56	50,548.42	0.17%	1.16%	0.00%	8.00%	0.01%
Consolidated Edison Inc	ED	354.09	94.68	33,525.24	0.11%	3.34%	0.00%	3.50%	0.00%
Equifax Inc	EFX	122.91	237.10	29,141.72	0.10%	0.66%	0.00%	10.50%	0.01%
Edison International	EIX	380.80	70.10	26,693.80		3.99%			
Estee Lauder Cos Inc/The	EL	232.42	272.32	63,293.70	0.22%	0.88%	0.00%	14.00%	0.03%
Eastman Chemical Co	EMN	128.95	112.06	14,450.14	0.05%	2.71%	0.00%	8.00%	0.00%
Emerson Electric Co	EMR	594.00	98.05	58,241.70	0.20%	2.10%	0.00%	11.50%	0.02%
Enphase Energy Inc	ENPH	133.94	201.78	27,025.61				30.00%	
EOG Resources Inc	EOG	585.39	119.23	69,795.93	0.24%	2.52%	0.01%	16.00%	0.04%
EPAM Systems Inc	EPAM	56.88	296.61	16,870.88				23.50%	
Equinix Inc	EQIX	90.72	741.62	67,280.51	0.23%	1.67%	0.00%	15.00%	0.03%
Equity Residential	EQR	375.92	89.92	33,802.46		2.78%		-2.00%	
Eversource Energy	ES	344.75	88.19	30,403.15	0.10%	2.89%	0.00%	5.50%	0.01%
Essex Property Trust Inc	ESS	65.28	345.48	22,552.59		2.55%		-2.50%	
Eaton Corp PLC	ETN	399.57	151.76	60,638.74	0.21%	2.13%	0.00%	11.50%	0.02%
Entergy Corp	ETR	203.52	116.75	23,760.38	0.08%	3.46%	0.00%	3.00%	0.00%

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Etsy Inc	ETSY	127.03	124.28	15,787.66				29.00%	
Evergy Inc	EVRG	226.99	68.34	15,512.70	0.05%	3.35%	0.00%	7.50%	0.00%
Edwards Lifesciences Corp	EW	621.32	117.72	73,141.44	0.25%			12.50%	0.03%
Exelon Corp	EXC	980.14	47.63	46,683.93		2.83%			
Expeditors International of Washington Inc	EXPD	167.40	103.16	17,268.78	0.06%	1.12%	0.00%	11.50%	0.01%
Expedia Group Inc	EXPE	150.23	195.67	29,395.70					
Extra Space Storage Inc	EXR	134.15	205.60	27,581.86	0.09%	2.92%	0.00%	6.00%	0.01%
Ford Motor Co	F	3,947.97	16.91	66,760.11		2.37%		29.00%	
Diamondback Energy Inc	FANG	177.42	137.08	24,320.05		1.75%			
Fastenal Co	FAST	575.55	59.40	34,187.91	0.12%	2.09%	0.00%	8.50%	0.01%
Meta Platforms Inc	FB	2,309.08	222.36	513,447.03				21.50%	
Fortune Brands Home & Security Inc	FBHS	132.35	74.28	9,830.74	0.03%	1.51%	0.00%	11.00%	0.00%
Freeport-McMoRan Inc	FCX	1,454.78	49.74	72,360.81		1.21%		27.00%	
FactSet Research Systems Inc	FDS	37.80	434.15	16,409.57	0.06%	0.76%	0.00%	9.50%	0.01%
FedEx Corp	FDX	259.18	231.39	59,971.20	0.20%	1.30%	0.00%	13.00%	0.03%
FirstEnergy Corp	FE	570.90	45.86	26,181.61	0.09%	3.40%	0.00%	10.00%	0.01%
F5 Inc	FFIV	60.74	208.95	12,691.21	0.04%			7.00%	0.00%
Fidelity National Information Services Inc	FIS	609.59	100.42	61,215.13		1.87%		28.00%	
Fiserv Inc	FISV	652.20	101.40	66,132.78	0.23%			13.00%	0.03%
Fifth Third Bancorp	FITB	683.67	43.04	29,425.20	0.10%	2.79%	0.00%	11.50%	0.01%
FleetCor Technologies Inc	FLT	77.89	249.06	19,398.54	0.07%			11.00%	0.01%
FMC Corp	FMC	125.89	131.57	16,563.74	0.06%	1.61%	0.00%	10.50%	0.01%
Fox Corp	FOX	247.10	36.28	8,964.64		1.32%			
Fox Corp	FOXA	315.81	39.45	12,458.55	0.04%	1.22%	0.00%	10.50%	0.00%
First Republic Bank/CA	FRC	179.06	162.10	29,025.63	0.10%	0.54%	0.00%	13.50%	0.01%
Federal Realty Investment Trust	FRT	78.69	122.07	9,605.44	0.03%	3.51%	0.00%	2.50%	0.00%
Fortinet Inc	FTNT	160.82	341.74	54,956.92				24.00%	
Fortive Corp	FTV	359.07	60.93	21,877.89	0.07%	0.46%	0.00%	12.00%	0.01%
General Dynamics Corp	GD	278.14	241.18	67,080.84	0.23%	2.09%	0.00%	6.00%	0.01%
General Electric Co	GE	1,101.75	91.50	100,810.22	0.34%	0.35%	0.00%	15.00%	0.05%
Gilead Sciences Inc	GILD	1,253.89	59.45	74,543.58	0.25%	4.91%	0.01%	13.50%	0.03%
General Mills Inc	GIS	602.21	67.72	40,781.80	0.14%	3.01%	0.00%	3.50%	0.00%
Globe Life Inc	GL	99.18	100.60	9,977.31	0.03%	0.83%	0.00%	8.00%	0.00%
Corning Inc	GLW	845.65	36.91	31,212.79	0.11%	2.93%	0.00%	20.00%	0.02%
General Motors Co	GM	1,453.02	43.74	63,555.14	0.22%			12.00%	0.03%
Generac Holdings Inc	GNRC	63.78	297.26	18,960.43				23.50%	
Alphabet Inc	GOOG	315.64	2,792.99	881,576.57				23.50%	
Alphabet Inc	GOOGL	300.76	2,781.35	836,504.92					
Genuine Parts Co	GPC	141.95	126.02	17,888.16	0.06%	2.84%	0.00%	8.50%	0.01%
Global Payments Inc	GPN	281.97	136.84	38,584.50	0.13%	0.73%	0.00%	16.50%	0.02%
Garmin Ltd	GRMN	192.79	118.61	22,866.47	0.08%	2.46%	0.00%	10.00%	0.01%
Goldman Sachs Group Inc/The	GS	341.86	330.10	112,847.66	0.38%	2.42%	0.01%	8.50%	0.03%
WW Grainger Inc	GWW	51.10	515.79	26,357.90	0.09%	1.26%	0.00%	7.00%	0.01%
Halliburton Co	HAL	898.57	37.87	34,028.92	0.12%	1.27%	0.00%	9.50%	0.01%
Hasbro Inc	HAS	138.96	81.92	11,383.60	0.04%	3.42%	0.00%	11.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,444.83	14.62	21,123.37	0.07%	4.24%	0.00%	12.00%	0.01%
HCA Healthcare Inc	HCA	302.02	250.62	75,691.75	0.26%	0.89%	0.00%	12.50%	0.03%
Home Depot Inc/The	HD	1,033.35	299.33	309,312.66	1.05%	2.54%	0.03%	10.00%	0.11%
Hess Corp	HES	309.75	107.04	33,155.21		1.40%			
Hartford Financial Services Group Inc/The	HIG	331.65	71.81	23,815.57	0.08%	2.14%	0.00%	6.50%	0.01%
Huntington Ingalls Industries Inc	HII	40.07	199.44	7,990.96	0.03%	2.37%	0.00%	10.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	279.14	151.74	42,356.55					
Hologic Inc	HOLX	251.30	76.82	19,305.10				25.00%	
Honeywell International Inc	HON	685.48	194.58	133,381.09	0.45%	2.01%	0.01%	11.00%	0.05%
Hewlett Packard Enterprise Co	HPE	1,300.14	16.71	21,725.27	0.07%	2.87%	0.00%	6.50%	0.00%
HP Inc	HPQ	1,053.37	36.30	38,237.19	0.13%	2.75%	0.00%	15.50%	0.02%
Hormel Foods Corp	HRL	545.00	51.54	28,089.20	0.10%	2.02%	0.00%	6.50%	0.01%
Henry Schein Inc	HSIC	137.17	87.19	11,960.11	0.04%			7.00%	0.00%
Host Hotels & Resorts Inc	HST	714.15	19.43	13,875.93	0.05%	0.62%	0.00%	8.50%	0.00%
Hershey Co/The	HSY	145.63	216.63	31,547.39	0.11%	1.66%	0.00%	6.00%	0.01%
Humana Inc	HUM	126.74	435.17	55,154.75	0.19%	0.72%	0.00%	12.00%	0.02%
Howmet Aerospace Inc	HWM	418.91	35.94	15,055.45	0.05%	0.22%	0.00%	12.50%	0.01%
International Business Machines Corp	IBM	899.31	130.02	116,928.29	0.40%	5.05%	0.02%	0.50%	0.00%
Intercontinental Exchange Inc	ICE	560.44	132.12	74,044.80	0.25%	1.15%	0.00%	8.00%	0.02%
IDEXX Laboratories Inc	IDXX	84.25	547.06	46,089.26	0.16%			14.00%	0.02%
IDEX Corp	IEX	76.11	191.73	14,591.61	0.05%	1.13%	0.00%	8.00%	0.00%
International Flavors & Fragrances Inc	IFF	254.75	131.33	33,455.66	0.11%	2.41%	0.00%	7.00%	0.01%
Illumina Inc	ILMN	157.08	349.40	54,882.01	0.19%			10.00%	0.02%
Incyte Corp	INCY	221.33	79.42	17,577.63				25.50%	
Intel Corp	INTC	4,088.70	49.56	202,635.77	0.69%	2.95%	0.02%	6.00%	0.04%
Intuit Inc	INTU	282.81	480.84	135,987.32	0.46%	0.57%	0.00%	18.50%	0.09%
International Paper Co	IP	374.89	46.15	17,301.08	0.06%	4.01%	0.00%	12.50%	0.01%
Interpublic Group of Cos Inc/The	IPG	393.96	35.45	13,965.88	0.05%	3.27%	0.00%	12.00%	0.01%
IPG Photonics Corp	IPGP	52.94	109.76	5,810.58	0.02%			17.00%	0.00%
IQVIA Holdings Inc	IQV	190.91	231.21	44,140.76	0.15%			14.50%	0.02%
Ingersoll Rand Inc	IR	407.97	50.35	20,541.19		0.16%			
Iron Mountain Inc	IRM	289.83	55.41	16,059.48	0.05%	4.46%	0.00%	10.00%	0.01%
Intuitive Surgical Inc	ISRG	359.20	301.68	108,361.95	0.37%			13.00%	0.05%
Gartner Inc	IT	82.29	297.46	24,477.09				20.50%	
Illinois Tool Works Inc	ITW	311.90	209.40	65,311.86	0.22%	2.33%	0.01%	11.00%	0.02%
Invesco Ltd	IVZ	454.96	23.06	10,491.42	0.04%	2.95%	0.00%	15.50%	0.01%
Jacobs Engineering Group Inc	J	129.22	137.81	17,807.39	0.06%	0.67%	0.00%	15.00%	0.01%
JB Hunt Transport Services Inc	JBHT	104.85	200.79	21,052.83	0.07%	0.80%	0.00%	11.00%	0.01%
Johnson Controls International plc	JCI	702.63	65.57	46,071.25	0.16%	2.14%	0.00%	14.00%	0.02%
Jack Henry & Associates Inc	JKHY	72.83	197.05	14,350.17	0.05%	0.99%	0.00%	10.50%	0.01%
Johnson & Johnson	JNJ	2,629.62	177.23	466,046.67	1.59%	2.39%	0.04%	8.00%	0.13%
Juniper Networks Inc	JNPR	322.57	37.16	11,986.66	0.04%	2.26%	0.00%	9.00%	0.00%
JPMorgan Chase & Co	JPM	2,952.81	136.32	402,526.92	1.37%	2.93%	0.04%	7.50%	0.10%
Kellogg Co	K	340.16	64.49	21,936.66	0.07%	3.60%	0.00%	3.50%	0.00%
KeyCorp	KEY	920.13	22.38	20,592.49	0.07%	3.49%	0.00%	9.50%	0.01%
Keysight Technologies Inc	KEYS	181.98	157.97	28,746.59	0.10%			13.00%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Kraft Heinz Co/The	KHC	1,224.89	39.39	48,248.57	0.16%	4.06%	0.01%	4.00%	0.01%
Kimco Realty Corp	KIM	617.92	24.70	15,262.50	0.05%	3.08%	0.00%	8.50%	0.00%
KLA Corp	KLAC	150.72	366.06	55,170.73		1.15%		21.00%	
Kimberly-Clark Corp	KMB	336.93	123.16	41,496.05	0.14%	3.77%	0.01%	5.50%	0.01%
Kinder Morgan Inc	KMI	2,267.49	18.91	42,878.14	0.15%	5.71%	0.01%	19.00%	0.03%
CarMax Inc	KMX	161.68	96.48	15,598.89	0.05%			13.50%	0.01%
Coca-Cola Co/The	KO	4,335.00	62.00	268,769.69	0.92%	2.84%	0.03%	7.00%	0.06%
Kroger Co/The	KR	723.31	57.37	41,496.18	0.14%	1.46%	0.00%	6.50%	0.01%
Loews Corp	L	246.39	64.82	15,971.26	0.05%	0.39%	0.00%	12.50%	0.01%
Leidos Holdings Inc	LDOS	136.34	108.02	14,727.66	0.05%	1.33%	0.00%	8.50%	0.00%
Lennar Corp	LEN	257.31	81.17	20,885.53	0.07%	1.85%	0.00%	8.50%	0.01%
Laboratory Corp of America Holdings	LH	93.40	263.66	24,625.84	0.08%			6.00%	0.01%
L3Harris Technologies Inc	LHX	193.06	248.47	47,969.62		1.80%			
Linde PLC	LIN	507.23	319.43	162,022.88		1.47%			
LKQ Corp	LKQ	284.99	45.41	12,941.40	0.04%	2.20%	0.00%	14.00%	0.01%
Eli Lilly & Co	LLY	952.35	286.37	272,723.61	0.93%	1.37%	0.01%	11.50%	0.11%
Lockheed Martin Corp	LMT	266.53	441.40	117,648.11	0.40%	2.54%	0.01%	6.50%	0.03%
Lincoln National Corp	LNC	172.46	65.36	11,271.66	0.04%	2.75%	0.00%	11.50%	0.00%
Alliant Energy Corp	LNT	250.48	62.48	15,649.93	0.05%	2.74%	0.00%	4.50%	0.00%
Lowe's Cos Inc	LOW	661.56	202.19	133,761.02	0.46%	1.58%	0.01%	15.50%	0.07%
Lam Research Corp	LRCX	139.50	537.61	74,996.60	0.26%	1.12%	0.00%	17.00%	0.04%
Lumen Technologies Inc	LUMN	1,023.37	11.27	11,533.40	0.04%	8.87%	0.00%	3.50%	0.00%
Southwest Airlines Co	LUV	592.34	45.80	27,129.26				29.50%	
Las Vegas Sands Corp	LVS	763.99	38.87	29,696.37	0.10%			17.00%	0.02%
Lamb Weston Holdings Inc	LW	145.20	59.91	8,699.17	0.03%	1.64%	0.00%	6.00%	0.00%
LyondellBasell Industries NV	LYB	328.01	102.82	33,725.99	0.11%	4.40%	0.01%	5.50%	0.01%
Live Nation Entertainment Inc	LYV	224.63	117.64	26,425.00					
Mastercard Inc	MA	969.73	357.38	346,561.75	1.18%	0.55%	0.01%	13.00%	0.15%
Mid-America Apartment Communities Inc	MAA	115.34	209.45	24,158.17	0.08%	2.08%	0.00%	8.50%	0.01%
Marriott International Inc/MD	MAR	327.25	175.75	57,514.89	0.20%			17.50%	0.03%
Masco Corp	MAS	236.52	51.00	12,062.72	0.04%	2.20%	0.00%	9.00%	0.00%
McDonald's Corp	MCD	743.59	247.28	183,873.70	0.63%	2.23%	0.01%	10.00%	0.06%
Microchip Technology Inc	MCHP	555.99	75.14	41,777.16	0.14%	1.35%	0.00%	10.00%	0.01%
McKesson Corp	MCK	149.80	306.13	45,857.66	0.16%	0.61%	0.00%	10.00%	0.02%
Moody's Corp	MCO	185.38	337.41	62,548.05	0.21%	0.83%	0.00%	9.00%	0.02%
Mondelez International Inc	MDLZ	1,388.33	62.78	87,159.23	0.30%	2.23%	0.01%	8.00%	0.02%
Medtronic PLC	MDT	1,341.54	110.95	148,843.75	0.51%	2.27%	0.01%	8.50%	0.04%
MetLife Inc	MET	825.08	70.28	57,986.48	0.20%	2.73%	0.01%	7.50%	0.01%
MGM Resorts International	MGM	435.33	41.94	18,257.87		0.02%		25.00%	
Mohawk Industries Inc	MHK	65.07	124.20	8,081.82	0.03%			10.50%	0.00%
McCormick & Co Inc/MD	MKC	250.23	99.80	24,972.55	0.09%	1.48%	0.00%	6.00%	0.01%
MarketAxess Holdings Inc	MKTX	37.84	340.20	12,871.47	0.04%	0.82%	0.00%	14.00%	0.01%
Martin Marietta Materials Inc	MLM	62.40	384.89	24,015.21	0.08%	0.63%	0.00%	8.50%	0.01%
Marsh & McLennan Cos Inc	MMC	502.77	170.42	85,681.38	0.29%	1.26%	0.00%	12.00%	0.04%
3M Co	MMM	569.17	148.88	84,738.33	0.29%	4.00%	0.01%	6.00%	0.02%
Monster Beverage Corp	MNST	529.36	79.90	42,295.78	0.14%			13.00%	0.02%
Altria Group Inc	MO	1,817.26	52.25	94,951.68	0.32%	6.89%	0.02%	5.50%	0.02%
Molina Healthcare Inc	MOH	58.67	333.59	19,573.06	0.07%			11.00%	0.01%
Mosaic Co/The	MOS	368.31	66.50	24,492.55		0.68%		56.50%	
Marathon Petroleum Corp	MPC	558.57	85.50	47,758.08		2.71%			
Monolithic Power Systems Inc	MPWR	46.51	485.68	22,588.49	0.08%	0.62%	0.00%	18.00%	0.01%
Merck & Co Inc	MRK	2,527.73	82.05	207,400.57	0.71%	3.36%	0.02%	8.00%	0.06%
Moderna Inc	MRNA	403.02	172.26	69,424.23					
Marathon Oil Corp	MRO	730.77	25.11	18,349.51		1.12%			
Morgan Stanley	MS	1,781.30	87.40	155,685.53	0.53%	3.20%	0.02%	10.50%	0.06%
MSCI Inc	MSCI	81.27	502.88	40,868.05	0.14%	0.83%	0.00%	15.50%	0.02%
Microsoft Corp	MSFT	7,496.87	308.31	2,311,358.76	7.87%	0.80%	0.06%	17.50%	1.38%
Motorola Solutions Inc	MSI	167.45	242.20	40,555.91	0.14%	1.30%	0.00%	8.00%	0.01%
M&T Bank Corp	MTB	129.06	169.50	21,874.99	0.07%	2.83%	0.00%	8.00%	0.01%
Match Group Inc	MTCH	285.15	108.74	31,006.99	0.11%			18.50%	0.02%
Mettler-Toledo International Inc	MTD	22.74	1,373.19	31,220.85	0.11%			13.50%	0.01%
Micron Technology Inc	MU	1,116.67	77.89	86,977.19		0.51%		24.00%	
Norwegian Cruise Line Holdings Ltd	NCLH	417.09	21.88	9,125.84					
Nasdaq Inc	NDAQ	164.41	178.20	29,298.22	0.10%	1.21%	0.00%	6.50%	0.01%
Nordson Corp	NDSN	57.94	227.08	13,157.24	0.04%	0.90%	0.00%	13.50%	0.01%
NextEra Energy Inc	NEE	1,962.75	84.71	166,264.13	0.57%	2.01%	0.01%	11.00%	0.06%
Newmont Corp	NEM	792.55	79.45	62,968.02	0.21%	2.77%	0.01%	9.50%	0.02%
Netflix Inc	NFLX	443.96	374.59	166,304.10				23.50%	
NiSource Inc	NI	405.39	31.80	12,891.24	0.04%	2.96%	0.00%	10.50%	0.00%
NIKE Inc	NKE	1,276.29	134.56	171,737.31		0.91%		27.00%	
NortonLifeLock Inc	NLOK	582.27	26.52	15,441.91	0.05%	1.89%	0.00%	11.00%	0.01%
Nielsen Holdings PLC	NLSN	359.49	27.24	9,792.37		0.88%			
Northrop Grumman Corp	NOC	156.10	447.22	69,811.94	0.24%	1.40%	0.00%	8.50%	0.02%
ServiceNow Inc	NOW	200.00	556.89	111,378.00				44.50%	
NRG Energy Inc	NRG	242.15	38.36	9,289.03		3.65%		-10.50%	
Norfolk Southern Corp	NSC	239.78	285.22	68,389.20	0.23%	1.74%	0.00%	10.00%	0.02%
NetApp Inc	NTAP	222.54	83.00	18,470.49	0.06%	2.41%	0.00%	8.00%	0.01%
Northern Trust Corp	NTRS	207.94	116.45	24,215.08	0.08%	2.40%	0.00%	8.00%	0.01%
Nucor Corp	NUE	268.41	148.65	39,898.40	0.14%	1.35%	0.00%	12.00%	0.02%
NVIDIA Corp	NVDA	2,510.00	272.86	684,878.60		0.06%		21.50%	
NVR Inc	NVR	3.36	4,467.27	15,010.03	0.05%			5.50%	0.00%
Newell Brands Inc	NWL	415.81	21.41	8,902.41		4.30%			
News Corp	NWS	198.48	22.52	4,469.84		0.89%			
News Corp	NWSA	390.87	22.15	8,657.86		0.90%			
NXP Semiconductors NV	NXPI	262.54	185.08	48,590.53	0.17%	1.83%	0.00%	12.00%	0.02%
Realty Income Corp	O	597.90	69.30	41,434.54	0.14%	4.28%	0.01%	3.50%	0.00%
Old Dominion Freight Line Inc	ODFL	114.86	298.68	34,307.58	0.12%	0.40%	0.00%	12.00%	0.01%
Organon & Co	OGN	253.64	34.93	8,859.54		3.21%			
ONEOK Inc	OKE	446.21	70.63	31,516.02	0.11%	5.30%	0.01%	12.00%	0.01%
Omnicom Group Inc	OMC	206.95	84.88	17,565.75	0.06%	3.30%	0.00%	6.00%	0.00%
Oracle Corp	ORCL	2,668.16	82.73	220,736.63	0.75%	1.55%	0.01%	10.00%	0.08%

STANDARD AND POOR'S 500 INDEX

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O'Reilly Automotive Inc	ORLY	66.30	684.96	45,410.11	0.15%			13.00%	0.02%
Otis Worldwide Corp	OTIS	424.96	76.95	32,700.83		1.25%			
Occidental Petroleum Corp	OXY	936.91	56.74	53,160.22		0.92%		30.50%	
Paramount Global	PARA	607.88	37.81	22,983.83	0.08%	2.54%	0.00%	7.00%	0.01%
Paycom Software Inc	PAYC	60.21	346.38	20,856.93	0.07%			20.00%	0.01%
Paychex Inc	PAYX	361.02	136.47	49,267.99	0.17%	1.93%	0.00%	9.00%	0.02%
People's United Financial Inc	PBCT	429.67	19.99	8,589.12	0.03%	3.65%	0.00%	2.50%	0.00%
PACCAR Inc	PCAR	347.68	88.07	30,619.74	0.10%	1.54%	0.00%	5.00%	0.01%
Healthpeak Properties Inc	PEAK	539.50	34.33	18,521.04		3.50%		-7.50%	
Public Service Enterprise Group Inc	PEG	502.08	70.00	35,145.46	0.12%	3.09%	0.00%	4.00%	0.00%
Penn National Gaming Inc	PENN	168.32	42.42	7,140.26				28.00%	
PepsiCo Inc	PEP	1,383.25	167.38	231,528.22	0.79%	2.57%	0.02%	6.50%	0.05%
Pfizer Inc	PFE	5,647.77	51.77	292,385.26	1.00%	3.09%	0.03%	6.50%	0.06%
Principal Financial Group Inc	PFG	261.23	73.41	19,176.75	0.07%	3.49%	0.00%	6.00%	0.00%
Procter & Gamble Co/The	PG	2,397.07	152.80	366,271.68	1.25%	2.28%	0.03%	6.50%	0.08%
Progressive Corp/The	PGR	584.88	113.99	66,670.36	0.23%	0.35%	0.00%	4.50%	0.01%
Parker-Hannifin Corp	PH	128.48	283.76	36,456.92	0.12%	1.45%	0.00%	13.50%	0.02%
PulteGroup Inc	PHM	241.43	41.90	10,115.71	0.03%	1.43%	0.00%	9.50%	0.00%
Packaging Corp of America	PKG	93.70	156.11	14,628.13	0.05%	2.56%	0.00%	9.00%	0.00%
PerkinElmer Inc	PKI	126.16	174.46	22,009.35	0.07%	0.16%	0.00%	10.00%	0.01%
Prologis Inc	PLD	739.75	161.48	119,454.02	0.41%	1.96%	0.01%	6.00%	0.02%
Philip Morris International Inc	PM	1,550.08	93.94	145,614.70	0.50%	5.32%	0.03%	7.00%	0.03%
PNC Financial Services Group Inc/The	PNC	418.56	184.45	77,203.39	0.26%	2.71%	0.01%	11.50%	0.03%
Pentair PLC	PNR	165.10	54.21	8,950.02	0.03%	1.55%	0.00%	14.00%	0.00%
Pinnacle West Capital Corp	PNW	112.93	78.10	8,819.99		4.35%		0.00%	
Pool Corp	POOL	40.13	422.85	16,967.28	0.06%	0.76%	0.00%	17.00%	0.01%
PPG Industries Inc	PPG	236.15	131.07	30,951.92	0.11%	1.80%	0.00%	10.00%	0.01%
PPL Corp	PPL	735.36	28.56	21,001.94		2.80%			
Prudential Financial Inc	PRU	376.43	118.17	44,482.26	0.15%	4.06%	0.01%	5.50%	0.01%
Public Storage	PSA	175.36	390.28	68,438.33	0.23%	2.05%	0.00%	8.00%	0.02%
Phillips 66	PSX	438.46	86.39	37,878.73	0.13%	4.26%	0.01%	17.00%	0.02%
PTC Inc	PTC	116.95	107.72	12,598.07					
PVH Corp	PVH	68.01	76.61	5,210.02	0.02%	0.20%	0.00%	14.00%	0.00%
Quanta Services Inc	PWR	142.69	131.61	18,779.43	0.06%	0.21%	0.00%	16.50%	0.01%
Pioneer Natural Resources Co	PXD	242.88	250.03	60,728.29		6.05%		23.00%	
PayPal Holdings Inc	PYPL	1,165.01	115.65	134,732.83	0.46%			16.00%	0.07%
QUALCOMM Inc	QCOM	1,127.00	152.82	172,228.14	0.59%	1.78%	0.01%	19.00%	0.11%
Qorvo Inc	QRVO	108.43	124.10	13,456.41	0.05%			14.50%	0.01%
Royal Caribbean Cruises Ltd	RCL	255.00	83.78	21,364.15					
Everest Re Group Ltd	RE	39.27	301.38	11,835.80	0.04%	2.06%	0.00%	11.00%	0.00%
Regency Centers Corp	REG	171.37	71.34	12,225.75	0.04%	3.50%	0.00%	12.50%	0.01%
Regeneron Pharmaceuticals Inc	REGN	106.72	698.42	74,532.59	0.25%			12.50%	0.03%
Regions Financial Corp	RF	937.15	22.26	20,860.87	0.07%	3.05%	0.00%	10.50%	0.01%
Robert Half International Inc	RHI	110.69	114.18	12,638.13	0.04%	1.51%	0.00%	7.50%	0.00%
Raymond James Financial Inc	RJF	207.60	109.91	22,817.54	0.08%	1.24%	0.00%	10.50%	0.01%
Ralph Lauren Corp	RL	46.29	113.44	5,250.68	0.02%	2.42%	0.00%	12.50%	0.00%
ResMed Inc	RMD	146.23	242.51	35,463.21	0.12%	0.69%	0.00%	8.50%	0.01%
Rockwell Automation Inc	ROK	116.20	280.03	32,538.37	0.11%	1.60%	0.00%	10.00%	0.01%
Rollins Inc	ROL	492.46	35.05	17,260.72	0.06%	1.14%	0.00%	10.50%	0.01%
Roper Technologies Inc	ROP	105.60	472.23	49,868.90	0.17%	0.53%	0.00%	8.50%	0.01%
Ross Stores Inc	ROST	350.89	90.46	31,741.69	0.11%	1.37%	0.00%	14.00%	0.02%
Republic Services Inc	RSG	315.79	132.50	41,841.65	0.14%	1.39%	0.00%	10.50%	0.01%
Raytheon Technologies Corp	RTX	1,490.27	99.07	147,640.85	0.50%	2.06%	0.01%	7.50%	0.04%
SBA Communications Corp	SBAC	108.02	344.10	37,168.65		0.83%		42.50%	
Signature Bank/New York NY	SBNY	62.57	293.49	18,363.38	0.06%	0.76%	0.00%	12.00%	0.01%
Starbucks Corp	SBUX	1,150.30	90.97	104,642.79	0.36%	2.15%	0.01%	16.50%	0.06%
Charles Schwab Corp/The	SCHW	1,814.62	84.31	152,990.70	0.52%	0.95%	0.00%	7.00%	0.04%
SolarEdge Technologies Inc	SEDG	55.12	322.37	17,767.42	0.06%			19.50%	0.01%
Sealed Air Corp	SEE	148.16	66.96	9,920.66	0.03%	1.19%	0.00%	13.50%	0.00%
Sherwin-Williams Co/The	SHW	260.55	249.62	65,037.99	0.22%	0.96%	0.00%	11.50%	0.03%
SVB Financial Group	SIVB	58.81	559.45	32,901.25	0.11%			5.00%	0.01%
J M Smucker Co/The	SJM	108.46	135.41	14,686.30	0.05%	2.92%	0.00%	4.00%	0.00%
Schlumberger NV	SLB	1,413.02	41.31	58,371.81	0.20%	1.21%	0.00%	11.50%	0.02%
Snap-on Inc	SNA	53.42	205.48	10,976.13	0.04%	2.76%	0.00%	4.50%	0.00%
Synopsys Inc	SNPS	153.10	333.27	51,023.30	0.17%			14.00%	0.02%
Southern Co/The	SO	1,059.80	72.51	76,846.39	0.26%	3.64%	0.01%	5.50%	0.01%
Simon Property Group Inc	SPG	328.34	131.56	43,196.67	0.15%	5.02%	0.01%	2.50%	0.00%
S&P Global Inc	SPGI	347.03	410.18	142,343.53	0.48%	0.83%	0.00%	10.50%	0.05%
Sempra Energy	SRE	315.77	168.12	53,087.59	0.18%	2.72%	0.00%	10.00%	0.02%
STERIS PLC	STE	100.13	241.77	24,207.70	0.08%	0.71%	0.00%	11.50%	0.01%
State Street Corp	STT	366.07	87.12	31,891.76	0.11%	2.62%	0.00%	8.00%	0.01%
Seagate Technology Holdings PLC	STX	218.90	89.90	19,678.93	0.07%	3.11%	0.00%	16.00%	0.01%
Constellation Brands Inc	STZ	164.34	230.32	37,850.56	0.13%	1.32%	0.00%	5.50%	0.01%
Stanley Black & Decker Inc	SWK	163.41	139.79	22,843.22	0.08%	2.26%	0.00%	6.00%	0.00%
Skyworks Solutions Inc	SWKS	161.67	133.28	21,547.51	0.07%	1.68%	0.00%	15.50%	0.01%
Synchrony Financial	SYF	521.27	34.81	18,145.48	0.06%	2.53%	0.00%	9.50%	0.01%
Stryker Corp	SYK	377.70	267.35	100,978.10	0.34%	1.04%	0.00%	8.50%	0.03%
Sysco Corp	SYY	507.45	81.65	41,433.05	0.14%	2.30%	0.00%	17.50%	0.02%
AT&T Inc	T	7,142.89	23.63	168,786.56	0.57%	4.70%	0.03%	3.00%	0.02%
Molson Coors Beverage Co	TAP	200.60	53.38	10,707.97		2.85%		41.00%	
TransDigm Group Inc	TDG	55.46	651.54	36,135.71	0.12%			16.50%	0.02%
Teledyne Technologies Inc	TDY	46.77	472.63	22,103.01	0.08%			14.50%	0.01%
Bio-Techne Corp	TECH	39.29	433.04	17,013.28	0.06%	0.30%	0.00%	17.50%	0.01%
TE Connectivity Ltd	TEL	325.58	130.98	42,643.81	0.15%	1.71%	0.00%	10.50%	0.02%
Teradyne Inc	TER	162.42	118.23	19,202.56	0.07%	0.37%	0.00%	8.50%	0.01%
Truist Financial Corp	TFC	1,328.99	56.70	75,353.90	0.26%	3.39%	0.01%	7.00%	0.02%
Teleflex Inc	TFX	46.90	354.83	16,642.24	0.06%	0.38%	0.00%	15.00%	0.01%
Target Corp	TGT	462.42	212.22	98,134.35	0.33%	1.70%	0.01%	15.00%	0.05%
TJX Cos Inc/The	TJX	1,175.23	60.58	71,195.31	0.24%	1.95%	0.00%	20.00%	0.05%
Thermo Fisher Scientific Inc	TMO	391.19	590.65	231,057.55	0.79%	0.20%	0.00%	15.50%	0.12%
T-Mobile US Inc	TMUS	1,249.29	128.35	160,346.37	0.55%			7.50%	0.04%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Tapestry Inc	TPR	263.99	37.15	9,807.23	0.03%	2.69%	0.00%	10.00%	0.00%
Trimble Inc	TRMB	251.22	72.14	18,122.72	0.06%			10.00%	0.01%
T Rowe Price Group Inc	TROW	227.81	151.19	34,442.59	0.12%	3.17%	0.00%	12.00%	0.01%
Travelers Cos Inc/The	TRV	241.50	182.73	44,129.48	0.15%	1.93%	0.00%	8.00%	0.01%
Tractor Supply Co	TSCO	112.15	233.37	26,171.51	0.09%	1.58%	0.00%	14.50%	0.01%
Tesla Inc	TSLA	1,033.51	1,077.60	1,113,708.22				51.50%	
Tyson Foods Inc	TSN	292.46	89.63	26,212.74	0.09%	2.05%	0.00%	6.00%	0.01%
Trane Technologies PLC	TT	233.54	152.70	35,661.25		1.76%			
Take-Two Interactive Software Inc	TTWO	115.42	153.74	17,744.06	0.06%			15.00%	0.01%
Twitter Inc	TWTR	800.64	38.69	30,976.80				39.00%	
Texas Instruments Inc	TXN	923.55	183.48	169,452.40	0.58%	2.51%	0.01%	8.50%	0.05%
Textron Inc	TXT	216.33	74.38	16,090.55	0.05%	0.11%	0.00%	8.50%	0.00%
Tyler Technologies Inc	TYL	41.43	444.89	18,432.24	0.06%			14.00%	0.01%
Under Armour Inc	UA	253.22	15.56	3,940.07					
Under Armour Inc	UAA	188.67	17.02	3,211.15				33.00%	
United Airlines Holdings Inc	UAL	323.61	46.36	15,002.61					
UDR Inc	UDR	325.40	57.37	18,668.31	0.06%	2.65%	0.00%	10.50%	0.01%
Universal Health Services Inc	UHS	67.55	144.95	9,791.66	0.03%	0.55%	0.00%	11.00%	0.00%
Ulta Beauty Inc	ULTA	52.33	398.22	20,837.66	0.07%			15.50%	0.01%
UnitedHealth Group Inc	UNH	940.90	509.97	479,830.26	1.63%	1.14%	0.02%	12.00%	0.20%
Union Pacific Corp	UNP	628.39	273.21	171,681.61	0.58%	1.73%	0.01%	9.00%	0.05%
United Parcel Service Inc	UPS	733.44	214.46	157,293.33	0.54%	2.84%	0.02%	11.50%	0.06%
United Rentals Inc	URI	72.19	355.21	25,643.32	0.09%			12.50%	0.01%
US Bancorp	USB	1,485.04	53.15	78,929.82	0.27%	3.46%	0.01%	6.50%	0.02%
Visa Inc	V	1,658.42	221.77	367,788.69	1.25%	0.68%	0.01%	12.00%	0.15%
VF Corp	VFC	388.90	56.86	22,112.97	0.08%	3.52%	0.00%	9.50%	0.01%
Valero Energy Corp	VLO	409.42	101.54	41,572.20	0.14%	3.86%	0.01%	11.00%	0.02%
Vulcan Materials Co	VMC	132.89	183.70	24,412.63	0.08%	0.87%	0.00%	8.50%	0.01%
Vornado Realty Trust	VNO	191.72	45.32	8,688.93		4.68%		-19.00%	
Verisk Analytics Inc	VRSK	161.28	214.63	34,616.17	0.12%	0.58%	0.00%	10.50%	0.01%
VeriSign Inc	VRSN	110.17	222.46	24,507.75	0.08%			8.50%	0.01%
Vertex Pharmaceuticals Inc	VRTX	254.58	260.97	66,436.96	0.23%			18.50%	0.04%
Ventas Inc	VTR	399.55	61.76	24,676.15	0.08%	2.91%	0.00%	10.50%	0.01%
Viatris Inc	VTRS	1,209.58	10.88	13,160.19		4.41%			
Verizon Communications Inc	VZ	4,197.82	50.94	213,837.15	0.73%	5.03%	0.04%	2.50%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	185.29	96.17	17,819.34	0.06%	0.62%	0.00%	9.00%	0.01%
Waters Corp	WAT	60.52	310.39	18,783.56	0.06%			6.00%	0.00%
Walgreens Boots Alliance Inc	WBA	863.77	44.77	38,671.12	0.13%	4.27%	0.01%	7.50%	0.01%
Western Digital Corp	WDC	312.92	49.65	15,536.38				20.50%	
WEC Energy Group Inc	WEC	315.44	99.81	31,483.57	0.11%	2.92%	0.00%	6.00%	0.01%
Welltower Inc	WELL	447.28	96.14	43,001.50	0.15%	2.54%	0.00%	3.50%	0.01%
Wells Fargo & Co	WFC	3,801.59	48.46	184,225.00	0.63%	2.06%	0.01%	5.50%	0.03%
Whirlpool Corp	WHR	58.46	172.78	10,101.06	0.03%	4.05%	0.00%	9.50%	0.00%
Waste Management Inc	WM	415.16	158.50	65,802.86	0.22%	1.64%	0.00%	7.50%	0.02%
Williams Cos Inc/The	WMB	1,217.31	33.41	40,670.43	0.14%	5.09%	0.01%	10.00%	0.01%
Walmart Inc	WMT	2,751.78	148.92	409,795.08	1.40%	1.50%	0.02%	7.50%	0.10%
W R Berkley Corp	WRB	265.19	66.59	17,658.74	0.06%	0.52%	0.00%	17.50%	0.01%
Westrock Co	WRK	263.21	47.03	12,378.95	0.04%	2.13%	0.00%	17.00%	0.01%
West Pharmaceutical Services Inc	WST	74.28	410.71	30,508.36	0.10%	0.18%	0.00%	17.00%	0.02%
Willis Towers Watson PLC	WTW	117.75	236.22	27,813.96	0.09%	1.39%	0.00%	11.00%	0.01%
Weyerhaeuser Co	WY	747.08	37.90	28,314.14		1.90%		22.00%	
Wynn Resorts Ltd	WYNN	115.92	79.74	9,243.30				27.00%	
Xcel Energy Inc	XEL	544.21	72.17	39,275.92	0.13%	2.70%	0.00%	6.00%	0.01%
Exxon Mobil Corp	XOM	4,233.59	82.59	349,652.36		4.26%			
DENTSPLY SIRONA Inc	XRAY	217.55	49.22	10,708.01	0.04%	1.02%	0.00%	12.00%	0.00%
Xylem Inc/NY	XYL	180.09	85.26	15,354.73	0.05%	1.41%	0.00%	6.50%	0.00%
Yum! Brands Inc	YUM	288.98	118.53	34,252.92	0.12%	1.92%	0.00%	10.50%	0.01%
Zimmer Biomet Holdings Inc	ZBH	209.32	127.90	26,772.28	0.09%	0.75%	0.00%	7.00%	0.01%
Zebra Technologies Corp	ZBRA	53.08	413.70	21,959.20	0.07%			10.50%	0.01%
Zions Bancorp NA	ZION	151.90	65.56	9,958.24	0.03%	2.32%	0.00%	7.50%	0.00%
Zoetis Inc	ZTS	471.80	188.59	88,976.76	0.30%	0.69%	0.00%	11.00%	0.03%

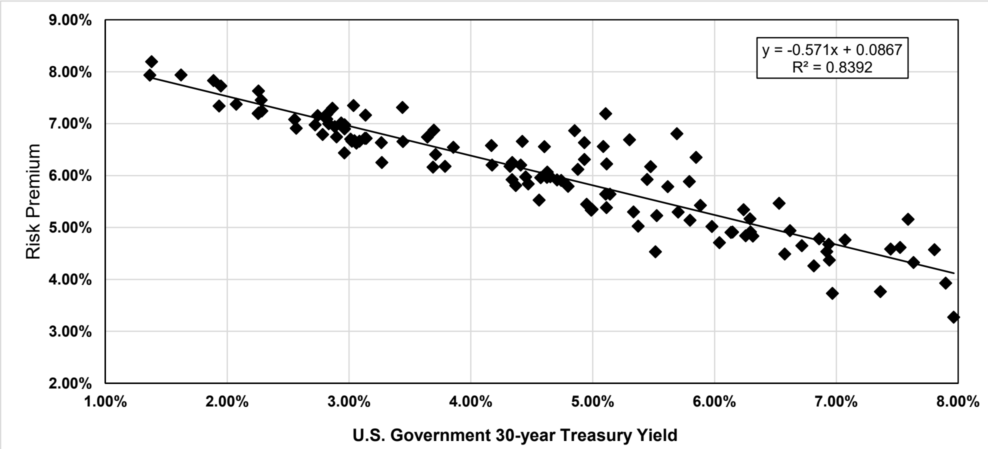
Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of March 31, 2022
[5] Source: Bloomberg Professional as of March 31, 2022
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of March 31, 2022
[9] Equals [7] x [8]
[10] Source: Value Line, as of March 31, 2022
[11] Equals [7] x [10]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.67%	1.95%	7.73%
2022.1	9.45%	2.25%	7.20%
AVERAGE	10.63%	4.58%	6.05%
MEDIAN	10.59%	4.62%	6.18%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.916070
R Square	0.839184
Adjusted R Square	0.837833
Standard Error	0.004186
Observations	121

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010882	0.010882	620.976321	0.000000
Residual	119	0.002085	0.000018		
Total	120	0.012967			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0867	0.00112	77.57	0.000000	0.084453	0.088878	0.084453	0.088878
U.S. Govt. 30-year Treasury	(0.5710)	0.02291	(24.92)	0.000000	(0.616399)	(0.525651)	(0.616399)	(0.525651)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	2.37%	7.31%	9.68%
Blue Chip Near-Term Projected Forecast (Q3 2022 - Q3 2023) [5]	3.12%	6.88%	10.00%
Blue Chip Long-Term Projected Forecast (2023-2027) [6]	3.40%	6.73%	10.13%
AVERAGE			9.94%

Notes:
[1] Source: Regulatory Research Associates, rate cases through March 31, 2022
[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: S&P Capital IQ Pro, 30-day average as of March 31, 2022
[5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 4, April 1, 2022, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086666 + (-0.571025 x Column [7])
[9] Equals Column [7] + Column [8]

COMPARISON OF MDU-ND AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
						Non-Volumetric Rate Design				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Test Year	Rate Base	Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design	Capital Cost Recovery
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Fully Forecast	Average	No	No	No	No	No
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Historical	Average	No	No	No	No	No
	Interstate Power & Light Co.	Iowa	Gas	Historical	Average	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	Average	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	Average	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Historical	Year End	No	Yes	No	Yes	No
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Average	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Year End	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Year End	Partial	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Year End	Partial	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Year End	Partial	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Year End	Partial	No	No	Yes	No
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Year End	Partial	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Average	No	No	No	No	No
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Year End	Partial	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Year End	Partial	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Fully Forecast	Average	No	No	No	No	No
	AEP Texas	Texas	Electric	Historical	Year End	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	Year End	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	Year End	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	Average	No	No	No	No	No
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	Year End	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Historical	Year End	Partial	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Average	Partial	No	No	Yes	No
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Average	Partial	No	No	Yes	No
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	Year End	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Year End	Full	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Year End	Partial	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	Year End	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Historical	Year End	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Year End	Partial	No	No	Yes	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Fully Forecast	Average	Partial	No	No	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Average	Partial	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	Year End	Partial	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	Year End	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Average	Partial	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	Average	Partial	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Average	Partial	Yes	No	Yes	No
	Entergy Texas Inc.	Texas	Electric	Historical	Year End	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Year End	Partial	No	No	Yes	No
	Evergy Metro Inc.	Kansas	Electric	Historical	Year End	No	No	No	No	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Year End	Partial	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Year End	Partial	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Year End	Full	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Partially Forecast	Average	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	Average	No	No	No	No	Yes
	Gulf Power Co.	Florida	Electric	Fully Forecast	Average	No	No	No	No	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	Average	No	No	No	No	Yes
	Lone Star Transmission LLC	Texas	Electric	Historical	Year End	No	No	No	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	Average	Partial	No	No	Yes	No
	NorthWestern Corporation	Montana	Gas	Historical	Average	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Historical	Year End	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Historical	Average	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Historical	Average	No	No	No	No	No
OGE Energy Corporation	Oklahoma Gas and Electric Co.	Arkansas	Electric	Historical	Average	Partial	Yes	No	Yes	Yes
	Oklahoma Gas & Electric Co.	Oklahoma	Electric	Historical	Year End	Partial	No	No	Yes	Yes
Otter Tail Corporation	Otter Tail Power Co.	Minnesota	Electric	Fully Forecast	Average	No	No	No	No	No
	Otter Tail Power Co.	North Dakota	Electric	Fully Forecast	Average	No	No	No	No	Yes
	Otter Tail Power Co.	South Dakota	Electric	Historical	Average	No	No	No	No	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Fully Forecast	Year End	Partial	No	No	Yes	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	Average	No	Yes	No	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	Average	No	Yes	No	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	Average	No	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Average	Partial	No	No	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Year End	Partial	Yes	No	Yes	No
	Chattanooga Gas Co.	Tennessee	Gas	Fully Forecast	Average	Partial	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Historical	Average	Partial	No	No	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Average	Partial	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Year End	Partial	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Average	Partial	Yes	No	Yes	No
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	Average	No	No	No	No	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Historical	Year End	No	No	No	No	No
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	Average	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	Average	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Average	Partial	No	No	Yes	Yes

COMPARISON OF MDU-ND AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]		[2]		[3]		[4]		[5]		[6]		[7]	
										Non-Volumetric Rate Design							
Proxy Group Company	**Operating Subsidiary**	**Jurisdiction**	**Service**	**Test Year**		**Rate Base**		**Revenue Decoupling**		**Formula-based rates**		**Straight Fixed-Variable Rate Design**		**Non-Volumetric Rate Design**		**Capital Cost Recovery**	
	Southwestern Public Service Co.	Texas	Electric		Historical		Year End		No		No		No		No		Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Electric		Fully Forecast		Average		No		No		No		No		No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas		Fully Forecast		Average		No		No		No		No		No
								Revenue Decoupling		Formula-based rates		SFV Rates Design		Non-Volumetric Rate Design		CCRM	
Proxy Group Average				Fully Forecast	32	Year End	36	Full	2	Yes	16	Yes	3	Yes	44	Yes	44
				Partially Forecast	7	Average	42	Partial	35	No	62	No	75	No	34	No	34
				Historical	39			No	41								
				Forecast	50.00%	Year End	46.15%	RDM	47.44%	Yes	20.51%	Yes	3.85%	Yes	56.41%	CCRM	56.41%
MDU-ND [8]					Fully Forecast		Average		No		No		No		No		Yes

Notes:
[1] Sources: Regulatory Research Associates, effective as of March 31, 2022
[2] Sources: Regulatory Research Associates, effective as of March 31, 2022
[3] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit. NWE Electric Montana - Company 2020 Form 10-K. PSCO Electric CO and Southern TN - S&P Capital IQ Pro.
[4] Sources: Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[5] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[6] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[7] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[8] Data provided by MDU-ND

FLOTATION COST ADJUSTMENT -- MONTANA-DAKOTA PROXY GROUP

Company	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	$ 0.7200	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

[i] Offering Completion Date
[ii] Underwriting discount was 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	[10] Annualized Dividend	[11] Stock Price	[12] Dividend Yield	[13] Expected Dividend Yield	[14] Expected Dividend Yield Adjusted for Flotation Costs	[15] Value Line Earnings Growth	[16] Yahoo! Finance Earnings Growth	[17] Zacks Earnings Growth	[18] Average Earnings Growth	[19] ROE	[20] ROE Adjusted for Flotation Costs
ALLETE, Inc.	ALE	$2.60	$64.44	4.03%	4.15%	4.31%	6.00%	5.67%	n/a	5.84%	9.99%	10.15%
Alliant Energy Corporation	LNT	$1.71	$59.72	2.86%	2.94%	3.06%	4.50%	6.10%	6.10%	5.57%	8.51%	8.62%
Ameren Corporation	AEE	$2.36	$87.98	2.68%	2.78%	2.88%	6.50%	7.40%	7.20%	7.03%	9.81%	9.92%
American Electric Power Company, Inc.	AEP	$3.12	$93.63	3.33%	3.43%	3.57%	6.50%	6.10%	5.80%	6.13%	9.57%	9.70%
Duke Energy Corporation	DUK	$3.94	$104.74	3.76%	3.88%	4.03%	7.00%	5.85%	6.10%	6.32%	10.20%	10.35%
Entergy Corporation	ETR	$4.04	$109.57	3.69%	3.78%	3.92%	3.00%	6.00%	6.00%	5.00%	8.78%	8.92%
Evergy, Inc.	EVRG	$2.29	$64.00	3.58%	3.69%	3.83%	7.50%	5.12%	6.10%	6.24%	9.93%	10.07%
IDACORP, Inc.	IDA	$3.00	$108.85	2.76%	2.81%	2.92%	4.00%	4.40%	4.30%	4.23%	7.05%	7.16%
NextEra Energy, Inc.	NEE	$1.70	$80.31	2.12%	2.22%	2.31%	11.00%	9.95%	8.80%	9.92%	12.14%	12.22%
NorthWestern Corporation	NWE	$2.52	$59.44	4.24%	4.31%	4.47%	2.00%	4.50%	3.10%	3.20%	7.51%	7.67%
OGE Energy Corporation	OGE	$1.64	$38.44	4.27%	4.37%	4.53%	6.50%	3.90%	3.50%	4.63%	9.00%	9.17%
Otter Tail Corporation	OTTR	$1.65	$62.03	2.66%	2.75%	2.86%	4.50%	9.00%	n/a	6.75%	9.50%	9.61%
Portland General Electric Company	POR	$1.72	$52.99	3.25%	3.35%	3.48%	7.00%	7.15%	4.60%	6.25%	9.60%	9.73%
Southern Company	SO	$2.64	$67.65	3.90%	4.00%	4.16%	5.50%	6.20%	4.00%	5.23%	9.24%	9.39%
Xcel Energy Inc.	XEL	$1.95	$69.08	2.82%	2.91%	3.02%	6.00%	6.90%	6.40%	6.43%	9.35%	9.46%
Mean											9.34%	9.47%
Flotation Cost Adjustment											[21]	0.13%

Notes:
[1]-[4] Sources: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated November 19, 2002.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Source: Bloomberg Professional
[11] Source: Bloomberg Professional, equals 30-day average as of March 31, 2022
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Source: Value Line
[16] Source: Yahoo! Finance
[17] Source: Zacks
[18] Equals Average ([15], [16], [17])
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals Average ([20]) − Average ([19])

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2019Q4 - 2021Q3)				
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-term Debt Ratio	Total Capitalization
ALLETE, Inc.	ALE	56.83%	43.11%	0.00%	0.06%	100.00%
Alliant Energy Corporation	LNT	50.94%	46.17%	1.65%	1.24%	100.00%
Ameren Corporation	AEE	52.06%	46.18%	0.75%	1.01%	100.00%
American Electric Power Company, Inc.	AEP	47.41%	50.81%	0.00%	1.78%	100.00%
Duke Energy Corporation	DUK	52.14%	46.59%	0.00%	1.27%	100.00%
Entergy Corporation	ETR	46.85%	53.03%	0.11%	0.01%	100.00%
Evergy, Inc.	EVRG	57.78%	39.15%	0.00%	3.06%	100.00%
IDACORP, Inc.	IDA	53.86%	45.86%	0.28%	0.00%	100.00%
NextEra Energy, Inc.	NEE	59.91%	38.11%	0.00%	1.99%	100.00%
NorthWestern Corporation	NWE	47.02%	52.13%	0.00%	0.85%	100.00%
OGE Energy Corporation	OGE	53.59%	45.72%	0.00%	0.69%	100.00%
Otter Tail Corporation	OTTR	52.26%	46.13%	0.00%	1.62%	100.00%
Portland General Electric Company	POR	46.83%	51.11%	0.00%	2.06%	100.00%
Southern Company	SO	53.97%	44.97%	0.57%	0.49%	100.00%
Xcel Energy Inc.	XEL	53.73%	45.69%	0.00%	0.57%	100.00%
Average		52.35%	46.32%	0.22%	1.11%	
Median		52.26%	46.13%	0.00%	1.01%	
Maximum		59.91%	53.03%	1.65%	3.06%	
Minimum		46.83%	38.11%	0.00%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of the operating subsidiaries.
[2] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Capital IQ Pro have been excluded from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case No. PU-22-___

Direct Testimony

of

Joseph E. Geiger

Q. Please state your name and business address.

A. My name is Joseph E. Geiger 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 Generation in the power production department of Montana-Dakota Utilities Co. ("Montana-Dakota").

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

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

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical Engineering from the University of North Dakota. My work experience includes six years of experience as a plant engineer, nine years of experience in varying roles of plant supervision/management, and three years of generation development and operational responsibilities in my current position which includes coal-fired, gas-fired, and renewable generation.

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

A. The purpose of my testimony is to describe and provide cost estimate schedules for a variety of projects. These projects include:

- The Heskett IV combustion turbine project ("Heskett IV Project");
- The Water Pipeline Construction for Heskett III and Heskett IV;
- The shop modification for Heskett III and Heskett IV ("Heskett Shop Modification Project"); and
- The office building addition at Lewis & Clark II ("Lewis & Clark Office Addition Project")

Q. Please describe Montana-Dakota's Heskett IV Project.

A. The Project includes a natural gas-fired, 88 MW, simple cycle combustion turbine ("SCCT") and the associated facilities to interconnect with Montana-Dakota's existing electric system ("Interconnect"). The Heskett IV Project is located near Mandan, North Dakota adjacent to Montana-Dakota's R.M. Heskett Station III. Natural gas fuel will be supplied through an existing 10-inch pipeline ("NG Pipeline"), approximately 24 miles in length, interconnecting with the Northern Border Pipeline Company near St. Anthony, North Dakota, which also provides natural gas fuel to R.M. Heskett Station III. Operating and fire suppression water needs will be supplied through a 12-inch pipeline ("Water Pipeline"), approximately 2,684-feet in length, interconnecting with the City of Mandan water supply. A new administration building will be built in conjunction with the Heskett IV Project. The Heskett IV Project will be operated and maintained by a staff of six employees.

Q. Has the North Dakota Public Service Commission Granted an Advance Determination of Prudence (ADP) for the Heskett IV project?

A. On August 28, 2019, Montana-Dakota filed an application for an ADP for Heskett IV in Case No. PU-19-306 and for a certificate of public convenience and necessity (PCN) in Case No. PU-19-307 to construct, own, and operate Heskett IV. On August 5, 2020. The North Dakota Public Service Commission approved the ADP and PCN incorporating the Modified Settlement Agreement between Commission Staff and Montana-Dakota which was filed on July 23, 2020.

Q. What is a simple cycle combustion turbine?

A. A SCCT is generally built to start up quickly to serve peak capacity needs. In the SCCT, air is drawn in at the front of the unit and is compressed using rows of rotating blades. The compressed air is then sent to a combustion chamber where it is mixed with fuel and the mixture is ignited. The hot combustion gas is then expanded through rotating turbine blades delivering power through a shaft connected to the generator where electricity is produced.

Q. Please describe the major equipment chosen for Montana-Dakota's Heskett IV Project.

A. The equipment includes a General Electric 7E.03 ("7EA") heavy duty ("Frame") combustion turbine which is natural gas-fired, has a dry low NOx combustion system, evaporative inlet air cooling for power augmentation, a totally enclosed water-to-air cooled ("TEWAC") generator, and a closed cooling water system for cooling the generator heat exchangers, turbine supports, flame detectors, and lubrication oil. Other auxiliary equipment includes natural gas heating and filtration, fire detection and suppression, turbine control system, starting means, exhaust system, a continuous emissions monitoring system, an emergency backup generator, a high-voltage substation, transformers, power load center, and distribution equipment. The Heskett IV Project will share use of R.M. Heskett Station III's turbine water wash system, balance of plant control system, instrument air system, and service building, as well as the natural gas pipeline and water pipeline. The Frame Combustion Turbine was selected due to it being an ideal size to replace the Heskett coal units under MISO's generator interconnection replacement process as well as its lower capital cost, lower operation and maintenance cost, better emissions control, ability to perform on-site maintenance, lower natural gas inlet pressure requirement, less susceptibility to cold weather operational issues, and Montana-Dakota's operating experience associated with Frame SCCTs.

Q. Please describe the schedule for the Combustion Turbine construction.

A. The general works construction ("GWC") contract was awarded on March 28, 2022, with site activities commencing on mid-May 2022. The civil/structural portion of the GWC activities include site preparation, foundations, concrete flat work, and above ground structures. The mechanical portion of the GWC activities include heavy haul and setting the turbine and generator, receiving and handling all other equipment and materials, and erection of mechanical equipment and piping (including tie-ins to existing R.M. Heskett Station III systems). The electrical portion of the GWC activities include the installation of electrical equipment, enclosures, fixtures, and panels; as well as grounding, duct bank, cable tray, conduit, cabling, and wiring of all equipment. GWC substantial completion is expected by January 31, 2023. Commissioning and start-up activities will follow GWC substantial completion and are expected to take approximately three months.

Q. Please describe the schedule for the Water Pipeline construction.

A. Due to the retirement of Heskett Units I & II and the associated water intake structure, a replacement water supply source is needed to provide water for fire protection and evaporative cooling of the Heskett III & IV combustion turbines. Montana-Dakota has worked with consultants and the City of Mandan to develop a plan that will bring water from the City of Mandan's water treatment facility to the combustion turbine site. The Company analyzed a number of options for fire protection and evaporative cooling water sources, including the existing water intake structure, and the Water Pipeline Project was the most economic choice for future water needs. The project involves installing approximately 2,684 feet of 12-inch pipe that is designed to provide approximately 1,395 gallons per minute of fresh water to the Heskett Station. The project requires a Certificate of Corridor Compatibility ("Certificate") and Transmission Facility Route Permit from the North Dakota Public Service

Commission ("Commission"). On January 14, 2022, Montana-Dakota filed the Certificate with the Commission. A public hearing was held on April 5, 2022, at the Mandan City Hall. The Certificate of Corridor Compatibility was provided to Montana-Dakota on May 4, 2022. Construction of the project will commence in mid-May 2022, and is expected to take approximately three months to complete.

Q. Please provide the current breakdown of the Heskett IV Project and Water Pipeline capital cost estimates.

A. The Heskett IV Project capital cost, allocated to the North Dakota Electric jurisdiction, is $46,469,597 as shown on Statement B, Schedule B-1, page 11. The Water Pipeline cost, allocated to the North Dakota Electric Jurisdiction, is shown as FP-320773 on Statement B, Schedule B-1, page 3 and is estimated at $1,633,207.

Q. What is the anticipated schedule for commercial operation of the Heskett IV Project?

A. The Heskett IV Project is anticipated to be ready for commercial operation by April 2023.

Q. Please describe the Heskett Shop Modification Project.

A. The Heskett Shop Modification Project will provide a fabrication shop for plant employees to utilize in their maintenance and operation duties at Heskett III and Heskett IV through the modification of an existing cold storage building. The Heskett Shop Modification Project will also provide storage for tooling, materials, and parts needed to perform maintenance on Heskett III and Heskett IV through use of the existing cold storage building. The Heskett Shop Modification Project will replace heated storage and a fabrication shop that will be demolished due to Heskett I and Heskett II coal facility retirement and subsequent demolition. The existing fabrication shop has structural ties to the Heskett I and Heskett II coal facilities, therefore will not be able to be repurposed after plant demolition.

Q. Please provide the current breakdown of the Heskett Shop Modification Project capital cost estimates.

A. The Heskett Shop Modification Project capital cost estimate, as allocated to the North Dakota Electric Jurisdiction, is $355,571 and is shown as FP-318880 on Statement B, Schedule B-1, page 3.

Q. Please describe the Lewis & Clark Office Addition Project.

A. The Lewis & Clark Office Addition Project will provide a replacement for the recently demolished office at Lewis and Clark I. The office at Lewis and Clark I was integrated structurally to the Lewis and Clark I coal facility, therefore could not be repurposed after plant demolition. The Lewis & Clark Office Addition Project will provide a sanitary system, filing space, server space, HVAC, offices for Lewis & Clark II support staff, a conference room, and a designated lunch room.

Q. Please provide the current breakdown of the Lewis & Clark Office Addition Project capital cost estimates.

A. The Lewis & Clark Office Addition Project capital cost, as allocated to the North Dakota Electric Jurisdiction, is $1,288,773, as shown on Statement B, Schedule B-1, page 2 as FP-318827.

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-22-___

Direct Testimony

Of

Robert Frank

Q. Please state your name and business address.

A. My name is Robert Frank, and my business address is 400 North Fourth Street, Bismarck, North Dakota.

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

A. I am employed by Montana-Dakota Utilities Co. (Montana-Dakota) as the Director of Electric Transmission Engineering.

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

A. I have leadership responsibility for the engineering, design, construction, and maintenance of Montana-Dakota's electric transmission and substation facilities, including property and right-of-way acquisitions of the Company.

Q. Please outline your educational and professional background.

A. I received my Bachelor of Science degree in Electrical Engineering from North Dakota State University in 2002. I received my Master of Business Administration the University of Mary in 2008. In 2015, I attended the Utility Executive Course at the University of Idaho. I am a registered Professional Engineer in the State of North Dakota.

I began my career at Montana-Dakota in 2004 as a system protection engineer in the Electric Transmission Engineering Department. Throughout the next ten years, I worked on various substation and transmission projects gaining experience in engineering design, project management, construction management, and real estate transactions. In 2014, I accepted my current position.

Prior to joining Montana-Dakota, I worked for an industrial contractor as a field engineer providing engineering support to construction crews and project management duties.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's large transmission and substation capital projects that are planned for 2022 and 2023 and included in this case.

<u>MAJOR CAPITAL PROJECTS</u>

Q. Would you please describe the major capital projects that have been recently completed and the projects that are currently underway?

A. Yes. I will provide a description of each project including the need for each project.

<u>Beulah Transmission Substation Rebuild</u>

Q1. Please describe the Beulah Substation Rebuild project.

A. This project involved building a new Beulah 115/41.6 kV

Transmission Substation (Beulah 7th Street Transmission Substation) adjacent to the existing Beulah Transmission Substation. The substation is being rebuilt due to the age and condition of the existing facilities. The existing transmission lines will be re-routed to the new substation.

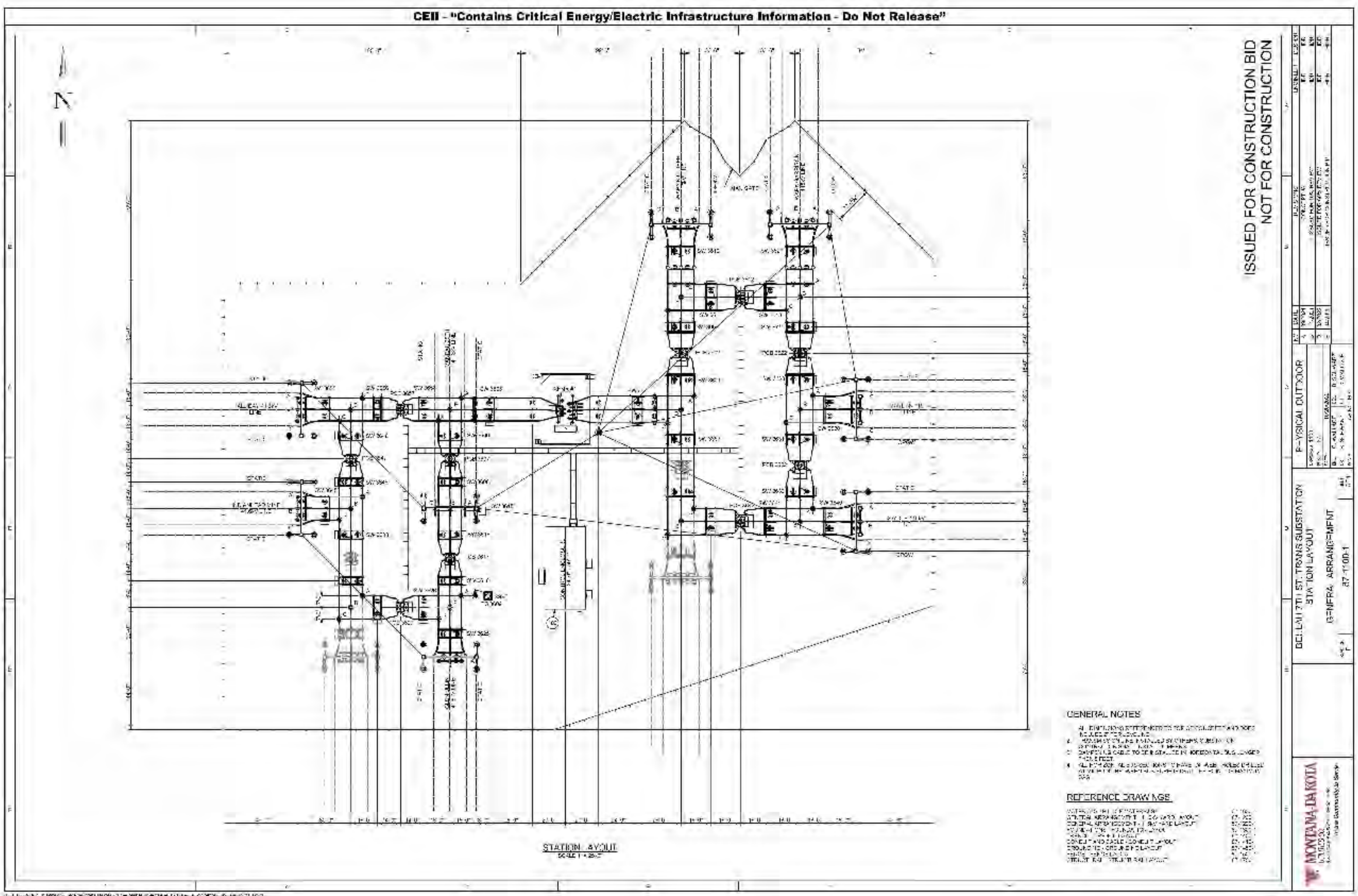


Figure 1 – Beulah 7th St Substation Layout

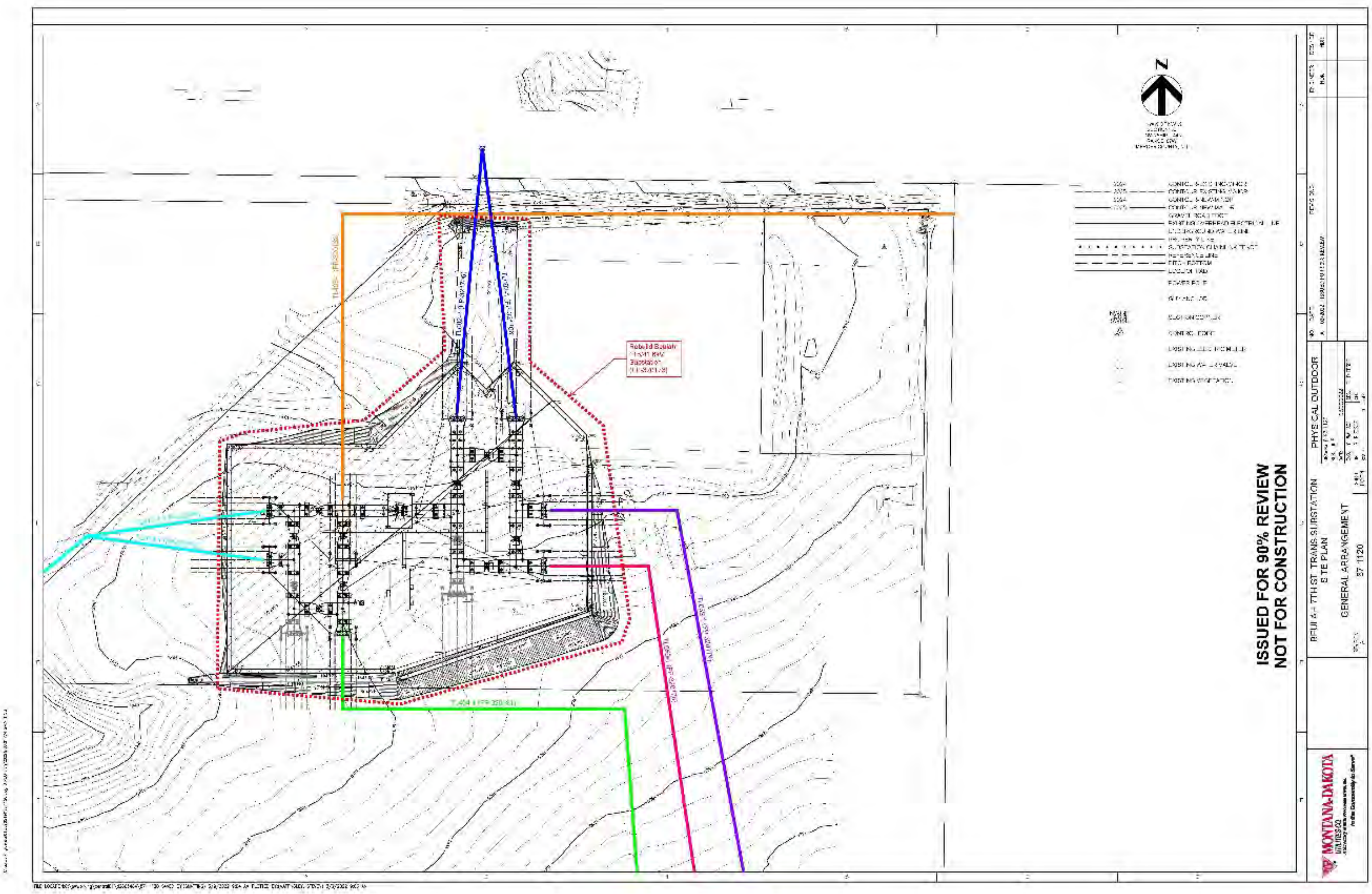


Figure 2 – Beulah 7th St Substation Transmission Line Reroutes

Q2. Why did Montana-Dakota undertake this project?

A. Montana-Dakota's System Protection Engineers identified the need to replace the protection and control systems within the substation. A full review was then performed of the components of the protection system and the other equipment in the substation. Most of the protection and control components are obsolete, the cables and other material have deteriorated and are failing, the yard equipment requires considerable maintenance and repair. The substation was built in 1962. As a result of this review, the decision was made to rebuild the entire substation.

Q3. What is the project timeline?

A. Project design was started in 2021 with construction starting the summer of 2022 and project completion in 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see a substantial improvement in reliability. The existing system protection systems are inadequate for the current system configuration, resulting in additional and extended outages to customer load served out of this substation. New substation equipment provides improved materials, technology, and designs.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative to a complete substation rebuild is to replace only those components that are not repairable. This alternative will delay some cost but will require continued construction at this facility resulting in higher costs replacing piece by piece and higher operation and maintenance costs.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Beulah 7th Street Transmission Substation - $4,883,162 as shown in FP-320173 found in Statement B, Schedule B-2, page 3.

Transmission line reroutes - $1,530,642 as shown on Statement B, Schedule B-2, pages 3 and 8 (as Various Project Numbers associated with the Reroute Line to New Beulah Substation and FP-300152) and on Statement B, Schedule B-1, page 8 as $700,503 of the Various Project Numbers associated with the Reroute Line.

<u>**Transmission Line Rebuild – Halliday to Dodge 41.6 kV Line**</u>

Q1. Please describe the Halliday to Dodge ND Line Rebuild project.

A. This project involves rebuilding the existing 41.6 kV transmission line that connects Halliday, ND to Dodge, ND. This is part of Montana-Dakota's transmission system that serves customers from Killdeer, ND to Beulah, ND.

Figure 3 – Halliday to Dodge Line Route

Q2. Why did Montana-Dakota undertake this project?

A. This transmission line section has a recent history of a significant number of outages. Routine patrols and inspections have indicated increased deterioration and wear. This line was constructed in 1947.

Q3. What is the project timeline?

A. Project design was started early 2022 with construction starting the summer of 2023 and project completion in late 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see improvement in reliability. The Company has modified its design standards for transmission line construction. Lines of this voltage class are now built using horizontal post insulators with a pole top shield wire instead of crossarms and no shield wire as was originally built.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative to a complete line rebuild is to replace components through routine inspections or repair following outages. This alternative will result in higher overall replacement costs and higher operation and maintenance costs.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Transmission line rebuild - $3,763,745 as shown as FP-318491 on Statement B, Schedule B-1, page 8.

<u>Transmission Line Rebuild – Crosby to Alamo 41.6 kV Line</u>

Q1. Please describe the Crosby to Alamo ND Line Rebuild project.

A. This project involves rebuilding the existing 41.6 kV transmission line that connects Crosby, ND to Alamo, ND. This is part of Montana-Dakota's transmission system that serves customers from Zahl, ND to Lignite, ND.

Figure 4 – Crosby to Alamo Line Route (Phase 1)

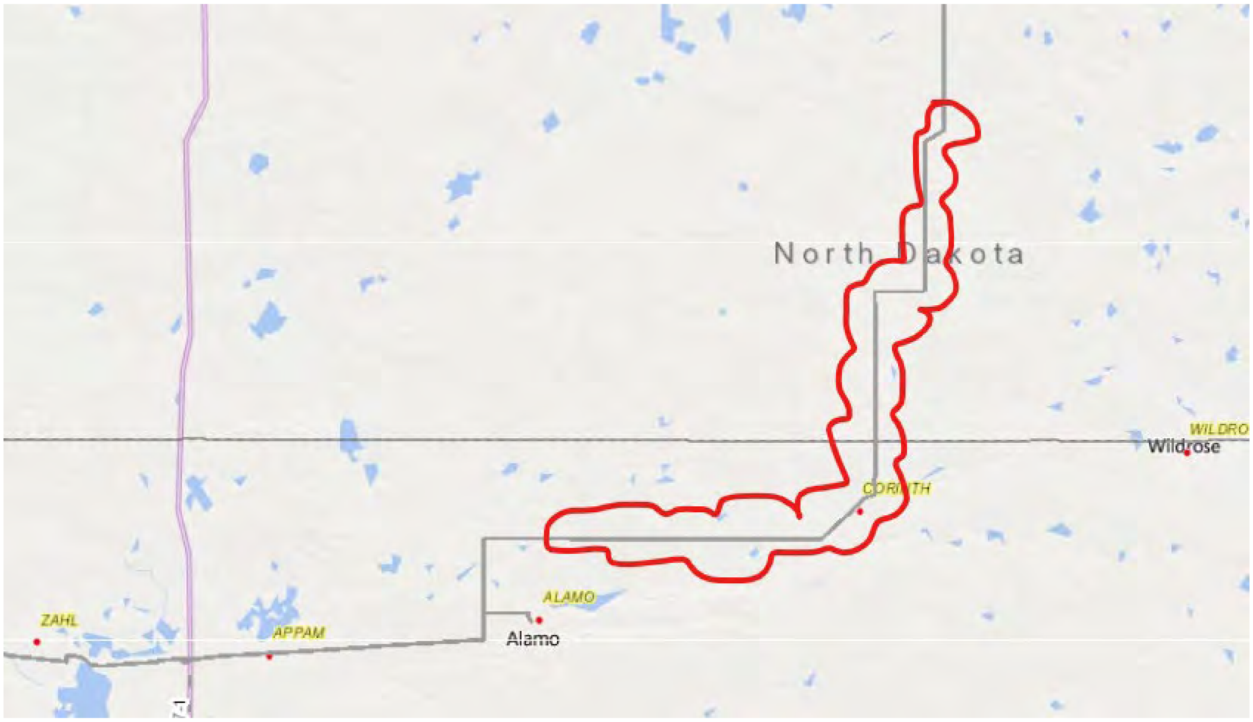


Figure 5 – Crosby to Alamo Line Route (Phase 2)

Q2. Why did Montana-Dakota undertake this project?

A. This transmission line section has a recent history of a significant number of outages. Routine patrols and inspections have indicated increased deterioration and wear. This line was constructed in 1948.

Q3. What is the project timeline?

A. Project design was started early 2022 with construction of Phase 1 starting the winter of 2022, construction of Phase 2 starting the summer of 2023, and project completion late 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see improvement in reliability. The Company has modified its design standards for transmission line construction. Lines of this voltage class are now built using horizontal post insulators with a pole top shield wire instead of crossarms and no shield wire as was originally built.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative to a complete line rebuild is to replace components through routine inspections or repair following outages. This alternative will result in higher overall replacement costs and higher operation and maintenance costs.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Phase 1 transmission line rebuild - $2,110,983 as shown as FP-302569 in Statement B, Schedule B-1, page 3.

Phase 2 transmission line rebuild - $1,548,187 as shown as FP-307501 in Statement B, Schedule B-1, page 8.

<u>Watford City Line Projects</u>

Q1. Please describe the Watford City line projects.

A. The Watford South Transmission Substation was designed to provide a termination point for the 34.5 kV transmission line that serves Alexander, ND. When pursuing line routes to make connections, right of way acquisition challenges were encountered and therefore the option to double circuit an existing 34.5 kV transmission line was pursued. A review of the current condition of that existing 34.5 kV transmission line confirmed the need to rebuild that circuit. The Watford City line projects involve building a double circuit 34.5 kV transmission line from the Watford South Substation to the Alexander line tap and also rebuilding an existing portion of the Watford 34.5 kV Loop Line.

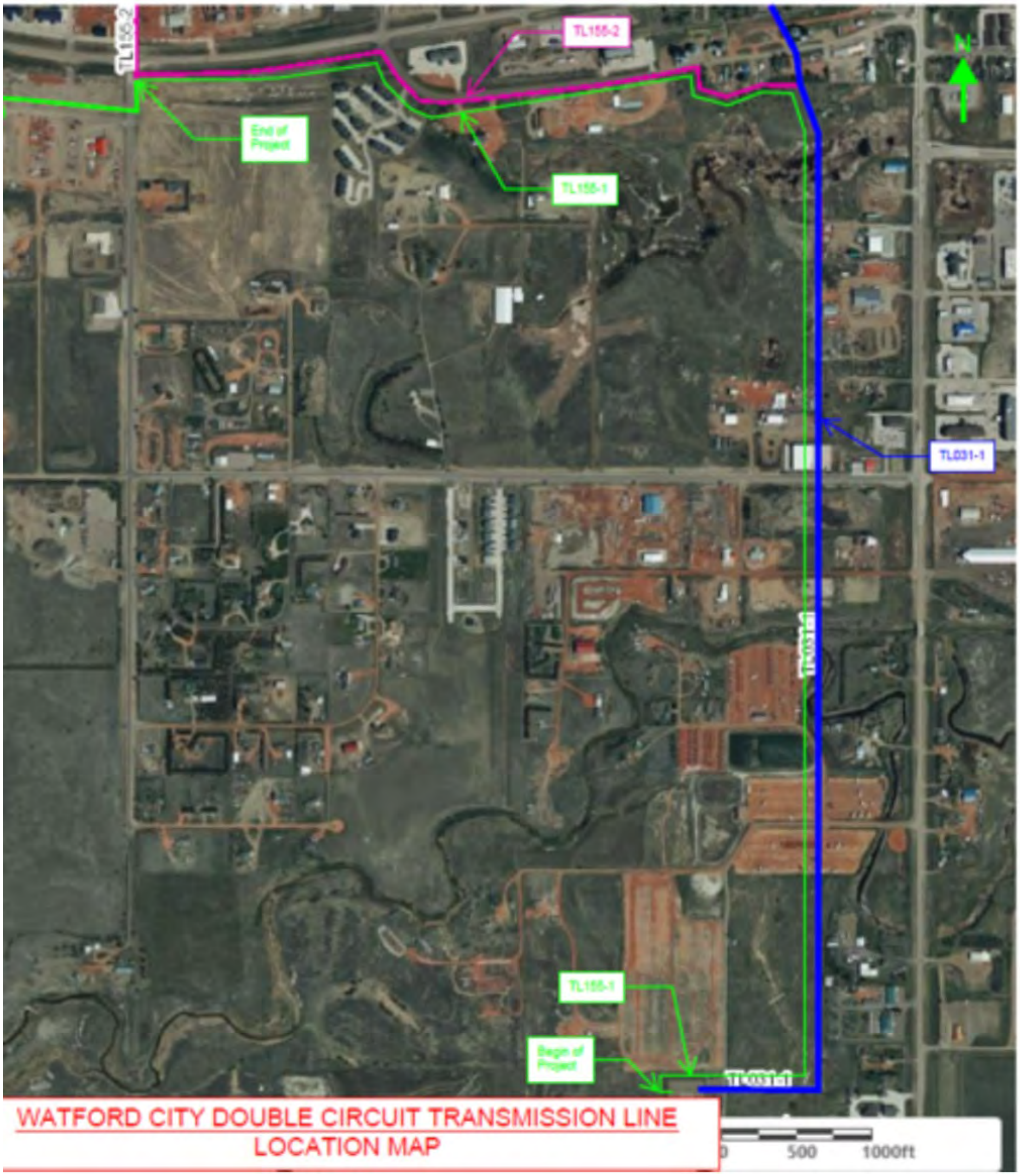


Figure 6 – Watford City Line Projects

Q2. Why did Montana-Dakota undertake this project?

A. The ability to separate Alexander from the Watford Loop Line reduces line mile exposure and increasing reliability to most of Montana-Dakota customers in the Watford City area. This original line being rebuilt was constructed in 1969.

Q3. What is the project timeline?

A. Project design was started in 2021 with construction starting the winter of 2022 and project completion the summer of 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. This circuit separation allows operation flexibility with more precise monitoring and control. The new double circuit transmission line will be constructed with new transmission line designs and construction standards.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative considered was to build a new transmission line on new right of way for the Alexander circuit. After considering several route options and interviewing landowners along those routes, the Company expected significant delays and cost increases to acquire new right of way in that area of Watford City.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Build new Alexander 34.5 kV transmission line - $1,312,225 as shown as FP-318214 in Statement B, Schedule B-1, pages 3 and 8.

Rebuild existing Watford 34.5 kV Loop line - $841,867 as shown as FP-316204 in Statement B, Schedule B-1, page 3.

<u>Mobile Distribution Substation</u>

Q1. Please describe the Mobile Distribution Substation project.

A. This project involves purchasing a new mobile distribution substation to provide a replacement option for construction and maintenance activities in existing distribution substations on Montana-Dakota's system. The substation can also be used for emergency use due to failed equipment. The substation is designed to be used for various voltage sources and loads with configuration settings in the substation. This allows use across most of Montana-Dakota's system.

Figure 7 – Mobile Distribution Substation Example

Q2. Why did Montana-Dakota undertake this project?

A. Montana-Dakota currently owns a mobile distribution substation that was purchased in 1966. The existing substation has a smaller transformer that is undersized for a large portion of the distribution substations on the system. The other equipment is aging and in need of replacement and the protection schemes are obsolete and do not coordinate and communicate with other distribution systems.

Furthermore, the Company owns two mobile transmission substations, one of which was purchased in 2021.

Q3. What is the project timeline?

A. The mobile substation will be designed and ordered in 2022 and delivered in 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota has developed the practice of having spare and mobile equipment available for equipment failures and emergency situations. Not having a mobile substation available can lead to more outages and/or longer outages to customer load.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative considered is rebuilding the existing mobile substation. This would require shipping the mobile substation to a manufacturer for 12-18 months for replacement of equipment and rebuilding of the transformer and trailer. This substation would then be unavailable for emergency or construction activities. The costs are also unknown until the substation is inspected and dismantled at the manufacturer upon arrival. Therefore, the decision was made to purchase a new mobile substation prior to determining what can be done with the existing substation.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Purchase Mobile Distribution Substation - $2,397,849 as shown as FP-307655 on Statement B, Schedule B-1, page 8.

<u>Linton, ND Distribution Substation Projects</u>

Q1. Please describe the Linton, ND Distribution Substation projects.

A. These projects involve constructing new distribution substations in Linton, ND. A new 41.6/4.16 kV substation will be constructed on purchased property near the existing distribution substation. A new 41.6/12.47 kV substation will be constructed at the old Linton Transmission Substation location. The Linton Transmission Substation will be retired as part of this project. Transmission lines within Linton will also be rerouted as part of this project.

Figure 8 – Mobile Distribution Substation Layout

Q2. Why did Montana-Dakota undertake this project?

A. The distribution substation has aged significantly. Most of the equipment in the substation was installed in 1965 as well as associated materials and components.

Q3. What is the project timeline?

A. Project design was started in 2021 with construction of the 41.6/4.16 kV substation occurring the summer of 2022. Retirement of the Linton Transmission Substation will start the summer of 2022 with construction of the 41.6/12.47 kV substation occurring during the summer of 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see an improvement in reliability with the installation of new distribution substations within the Linton area. New equipment and modern protection and control devices.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative to a complete substation rebuild is to replace only those components that are not repairable. This alternative will delay some cost but will require continued construction at this facility resulting in higher costs replacing piece by piece and higher operation and maintenance costs.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Construct Linton 41.6/4.16 kV Distribution Substation - $583,127 as shown as FP-321708 in Statement B, Schedule B-1, page 3.

Linton Transmission Substation Demolition – $375,000 as shown as FP-321739 in Statement B, Schedule B-1, page 3.

Construct Linton 41.6/12.47 kV Distribution Substation - $233,093 and Linton Transmission Line reroutes – $149,248 as shown as Various Project Numbers associated with Construct New Substation – Linton in Statement B, Schedule B-1, page 4.

Distribution Substation Projects

Q1. Please describe the Distribution Substation projects.

A. Montana-Dakota will undergo four large distribution substations. These projects include:

1) A new 60/12.47 kV substation on the west side of Williston, named the Williston Sand Creek Distribution Substation;
2) Rebuild the Watford City North Distribution Substation;
3) Install a second power transformer and associated equipment at the Mandan Collins Distribution Substation; and
4) Install a second power transformer and associated equipment at the Mandan Midway Distribution Substation.

Q2. Why did Montana-Dakota undertake these projects?

A. The substation construction projects are driven by load growth and reliability improvements in these locations. The new Willison Sand Creek Substation is driven by load growth in certain areas of Williston, ND.

Rebuilding the Watford City North Substation replaces aged equipment and provides a substation design for future load growth served from that substation. Installing multiple power transformers in existing substations provides redundancy to improve reliability and system operating flexibility.

Q3. What is the project timeline?

These projects will start the summer of 2022 and will be completed the fall of 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will see an improvement in reliability with the installation of new and rebuilt distribution substations or additions within existing substations. New equipment and modern protection and control devices.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The projects are closely related to load growth within certain areas in Montana-Dakota's service territory. No alternatives exist to building or adding equipment when experiencing load growth.

Q6. What are the costs of the project?

A. The costs of the project are as follows:

Build new Williston West Distribution Substation - $1,364,360 as shown as FP-100473 in Statement B, Schedule B-1, page 8.

Rebuild Watford City North Distribution Substation - $354,933 as shown as FP-317252 in Statement B, Schedule B-1, page 3.

Install second power transformer at Mandan Collins Distribution Substation - $1,296,254 as shown as FP-316186 in Statement B, Schedule B-1, page 3.

Install second power transformer at Mandan Midway Distribution Substation - $954,683 as shown as FP-315478 in Statement B, Schedule B-1, page 8.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Case No. PU-22-___

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-six years with the last thirteen years managing the system operations & planning department for Montana-Dakota.

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

A. I will provide support for the Company's North Dakota electric rate case application regarding the Company's current electric load forecast and an overview of the Company's two-way radio replacement project.

Q. What is the result of Montana-Dakota's latest electric customer long-term load forecast?

A. Montana-Dakota completes an update to its long-term electric forecast every year with the preliminary 2022-2041 forecast completed in September of 2021. The long-term electric load forecast is a twenty-year forecast of annual customer electric sales volumes along with a forecast of annual summer and winter customer peak demand.

The long-term electric sales forecast is developed separately by state (i.e. Montana, North Dakota and South Dakota) for the following customer classes; residential, small commercial and industrial, large commercial and industrial, street lighting, and miscellaneous; and then rolled into the Integrated System sales forecast. Seasonal peak demand forecasts are developed on an Integrated System basis and then allocated back to the states.

Q. What were the results of the September 2021 sales forecast?

A. Total Integrated System sales in the new forecast are projected to grow at a five-year average rate of 1.06% per year for 2021-2026 compared to the five-year historic average growth rate of 1.12% from 2015-2020. North Dakota's electric sales are forecasted to grow at 1.18% per year for 2021-2026 compared to a historic average growth rate of 0.24% per year from 2015-2020.

Overall, the Integrated System customer winter and summer demand is forecasted to grow at just over one percent per year with the Company remaining a summer peaking electric utility.

The five-year average sales forecast for North Dakota electric customers are:

Residential	0.36%
Small C&I	3.47%
Large C&I	0.08%
Street Lighting	0.00%
Miscellaneous	0.86%

It should also be noted that annual usage for electric street lighting dropped by 30 percent from 2019-2020 with the installation of LED street lights by the Company.

Q. Can you 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 1970s and 80s and comprises 70 radio towers, 350 mobile users, and 20 office base consoles and 30 remote handheld units. The system is obsolete and radio repeater towers are linked together by telephone interconnect systems which users have to key or dial codes and telephone numbers to hop from repeater tower to repeater tower to communicate. This creates challenges for effectively communicating with employees in not only normal conditions but especially under emergency conditions when employees may be working in different parts of the Company's service territory and are not familiar with the nearest radio tower location or area radio frequency.

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 and emergencies. The system also has the ability to track the location of users of the two-way radio system for scheduling and emergency dispatching.

The Company is working with the State of North Dakota to utilize existing state-controlled sites and towers which are used for the State's emergency radio system. This co-location allows for use of towers and locations that have existing fiber optic communications on-site via Dakota Carrier Network and eliminates the needs for multiple new microwave hops to connect tower sites together. The Company is in the second year of engineering designs for the project and is issuing a request for proposal to vendors the summer of 2022 with installations to begin the end of 2022.

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 our existing radio frequencies along with newer repeater equipment and telephone interconnects. This configuration today is hard for employees to use and does not lend itself to movement throughout the Company's service territory 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 the limitations of accessing area repeater sites and limitations 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, potentially leaving Montana-Dakota in a situation where employees 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 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 the North Dakota Electric Jurisdiction, is $2,432,044 in 2022 (as shown as FP-316490 and FP-316128 on Statement B, Schedule B-2, page 5 and 6) and $3,184,331 in 2023 (as shown as FP-316490 and FP-316128 on Statement B, Schedule B-2, page 9 and 11).

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-22-___

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 have a bachelor's in Organizational Management, in the Forbes School of Business, from Ashford University. I have been in the utility industry for nearly 30 years; 10 years in the field and 20 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.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's major field operation capital projects and the Work and Asset Management system deployment.

<u>MAJOR CAPITAL PROJECTS</u>

Q. Would you please describe the major field operation capital projects that are currently in progress?

A. Yes. I will provide a description of each project including the need for each project.

<u>Kenmare Office and Shop</u>

Q1. Please describe the construction of the new Kenmare Office and Shop capital project.

A. Our Kenmare location is an extension of the Williston District and is our central operations hub for nearly 2,000 customers and 11 communities in the surrounding area. There is a 3-person line crew and one district representative regularly reporting, in Kenmare, and supervision and operations support, from the Williston District, utilizing this space part-time. Our current facility is located at 220 South Central Avenue in Kenmare and is leased from the Canadian Pacific Railroad (CPR). Our records indicate we began leasing this land in the 1950's. There are 3 shop-style structures which provide office space, warehouse/material storage, and equipment/vehicle parking. Additionally, available space, outside the structure, is utilized for the storage of poles, transformers, and other material which can't be stored indoors.

Q2. Why did Montana-Dakota undertake this project?

A. The primary drivers for relocating our Kenmare facility are the drawbacks of the location and the potential risk that a continued lease present. Our current location is bordered by 4 sets of CPR railroad tracks and Middle Des Lacs Lake. On occasion, planned work and after-hours emergency response has been hindered by passing rail cars or the positioning of rail cars on sidings. Although there is no current information to suggest that CPR won't continue to lease this land to us, that risk remains inherent with continued leasing. Additionally, while we take great care to protect the lake from any contamination, our relocation will entirely mitigate the potential risk that an oil spill, from our storage and maintenance of transformers, could impact the lake in the future. The new facility will be located at 1228 Central Avenue North in Kenmare and will be a single structure, consisting of 1,000 square feet of office space, 3,500 square feet of warehouse/vehicle storage space, and sited on 1.03 acres.

Q3. What is the project timeline?

A. The Kenmare Office and Shop is anticipated to have construction completed by December 2022.

Q4. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. These facilities have reached the end of their useful and a significant investment is required if we stay. All things considered, we determined it is in the best interest of all stakeholders that we invest in a more suitable location which will better serve our customers, communities, and employees for the foreseeable future.

Q5. What are the costs of the project?

A. The Kenmare Office and Shop cost allocated to the North Dakota Electric jurisdiction is $1,365,316 as shown in FP-317154, FP-319040, FP-319116, FP-321203, FP-319117 on Statement B, Schedule B-1, pages 4 and 5.

<u>Other Building Projects</u>

Q1. Is the Company performing any other upgrades and improvements to other buildings?

A. Yes, there are building improvements planned for the Bismarck Service Center (BSC) and the Dickinson District Office.

The BSC is located at 909 Airport Road in Bismarck and the planned improvements consist of 3 separate capital projects:

1. Updating the north parking lot outdoor lights, which are vintage metal halide technology, to current, more efficient LED lighting. LED lighting is proven to both be less costly to operate and improve lighting in the area.
2. Installing an automatic gate in the BSC yard to improve the safety and security of our employees, facility, and the public. Currently, the gate is operated manually and is opened in the morning and remains open during normal business hours. There have been several occasions where non-company private vehicles and non-company private individuals have used our lot as a crossing to, respectfully, avoid the main intersection light or cross to the adjacent sidewalks. Additionally, the City of Bismarck has a planned project to install sidewalks on Expressway and we expect increased foot traffic along our lot perimeters when that project is complete.
3. Improvements to the engineering area. The BSC is a legacy site and is a large facility that we have made incremental improvements throughout the interior, over the years. The engineering area is one of the final areas to be improved, i.e., lighting, ceiling tiles, and flooring being the main components.

The Dickinson district office is located at 1133 West Broadway Street in Dickinson and is a legacy site. The planned improvements consist of 5 separate capital projects, all planned due to the age of the facility and components. The capital projects include:

1. Replacing ceiling tiles
2. Updating interior office lighting to LED
3. Replacing a garage door, including remote open/close capability,
4. Replacing a humidifier
5. Replacing exhaust fans

Q2. What are the costs of these projects?

The costs allocated to the North Dakota Electric jurisdiction for the the Dickinson District Office improvements (as shown as FP-317030, FP-317098, FP-321158, FP-321171, and FP-321172 on Statement B, Schedule B-1, page 6) are $125,730. The costs allocated to the North Dakota Electric jurisdiction for the BSC (as shown as FP-316843, FP-317038, and FP-320197 on Statement B, Schedule B-1, pages 9 and 10) are $184,361.

<u>Lines Growth</u>

Q1. Please describe the overhead and underground lines growth and service line growth capital projects for the Bismarck and Dickinson area?

A. These capital projects are considered “blanket funding projects”, meaning any single capital project, under $100,000 will be allocated to the blanket funding project, throughout any given plan addition year. Alternatively, any capital project estimated at $100,000 or above, is assigned to its own unique funding project and is not allocated to these blanket funding projects.

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 2022 and 2023 blanket funding projects are derived from a combination of 2 years of actual expense, historical expense, and future year load growth forecasts.

Q2. What are the costs of the project?

A. The costs allocated to the North Dakota Electric jurisdiction for Lines Growth are $2,292,981 in 2022 and $2,709,936 in 2023.

<u>Lines Replacement</u>

Q1. Please describe the overhead and underground line replacement and service lines replacement capital projects for the Bismarck and Dickinson area?

A. These capital projects are considered “blanket funding projects”, meaning any single capital project, under $100,000 will be allocated to the blanket funding project, throughout any given plan addition year. Alternatively, any project estimated at $100,000 or above, is assigned to its own unique funding project and is not allocated to these blanket funding projects.

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. We anticipate, in any given year, that replacements of our 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.

Q2. What are the costs of the project?

A. The costs allocated to the North Dakota Electric jurisdiction for Lines Growth are $2,643,050 in 2022 and $2,562,336 in 2023 as shown as FP-100785, FP-100768, FP-100772, FP-100792 in Statement B, Schedule B-1, pages 4, 8, and 9.

WORK AND ASSET MANAGEMENT

Q1. Please describe the Work and Asset Management system (Maximo)?

A. Maximo is a central database and system which stores asset information, work orders, work order tracking information, maintenance schedules, and is integrated to core utility systems, to ensure the safe and efficient operations of the electric and gas system.

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 and five-year implementation of Maximo.

- 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 2022-2023. This will include the full lifecycle of construction – initiate, design, estimate, plan/schedule, construct, close out and document construction work. This will be a full electronically driven construction process integrated to core systems, reducing touchpoints and data entry.
- Phase III is the implementation of transmission electric, electric generation and environmental sections and is planned for 2024.

Q4. How will the 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.

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 for North Dakota Electric jurisdiction is $2,159,511 as shown as FP-100550 on Statement B, Schedule B-1, page 10.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of North Dakota

Docket No. PU-22___

Direct Testimony

Of

Daryl Anderson

Q. Please state your name and business address.

A. My name is Daryl Anderson 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 Electric Distribution Services for Montana-Dakota Utilities Co. (Montana-Dakota).

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

A. My responsibilities include oversight and management of the electric distribution operations and engineering support services, including electric operations systems, metering, engineering systems, and electric distribution standards and procedures.

Q. Please outline your educational and professional background.

A. I hold an Associated Science Degree in Engineering from Minot

State College and a Bachelor of Science in Electrical and Electronics Engineering from North Dakota State University. My work experience at Montana-Dakota includes six years as an Electrical Engineer working at various District locations, twelve years working as the Electric Superintendent in the Rocky Mountain Region, and seven years as the Director of Distribution Engineering with both gas and electric utility responsibilities. I assumed my current position in 2015. Prior to my work at Montana-Dakota I worked five and a half years as an Electric Engineer for a combination gas and electric utility located in Iowa.

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

A. Yes, I have testified before the Wyoming and Montana Public Service Commissions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information regarding Montana-Dakota's Outage Management System (OMS) benefits, planned deployment timeline, and to provide an understanding and support for the increased costs involved to operate an Outage Management System at Montana-Dakota. I will also provide testimony on budgeted Capital Expenditures for purchases and replacements of Electric Distribution Transformers.

Q. Please briefly describe an Outage Management System.

A. An Outage Management System is a system comprised of hardware and software that is configured and integrated with many data sources that are specifically designed to manage electrical outages for a utility. The overall goal of an OMS is to increase service reliability and safety for customers and employees in Montana-Dakota's service territory.

Q. What has Montana-Dakota done to prepare for the deployment of an Outage Management System?

A. An Outage Management System is dependent on many other system deployments and processes within a utility in order for the system to be functional or even possible. These systems were not specifically installed for the purpose of an OMS, however they have the additional benefit of critical input to an OMS deployment. Critical system deployments necessary for an OMS are as follows at Montana-Dakota:

A) **GIS** – installed in 2003 – a geographical mapping system was deployed at Montana-Dakota and has been diligently improved to a point to provide the necessary input to support an OMS.

B) **Mobile Order System** – installed in 2005 – A Mobile Order system allows for employees to receive outage orders in a real time environment including emergency outage orders.

C) **Automated Meter Reading (AMR)** – installed in 2005 – Automated meter reading and especially the Fixed Network for real time reading is critical in providing meter power loss information to the OMS system. Montana-Dakota electric meters are approximately 95% communicating with the Fixed Network System.

D) **Distribution SCADA** – installed from 2017-2023 - Electric Distribution SCADA is an ongoing project to deploy Supervisory Control and Data Acquisition to the Distribution systems at Montana-Dakota and is expected to be fully deployed in 2023. SCADA provides a real time input to an OMS for confirmation of power loss at various points of the Distribution System Network.

E) **Distribution Management System (DMS)** – installed in 2017 – A Distribution Management System (DMS) was deployed at Montana-Dakota in 2017. This is an essential software platform that is used by an Electric Distribution Dispatcher to manage daily operations of the Electric Distribution System (EDS). This is a critical system deployment for an OMS to work properly.

Each of these systems having been deployed are capable of providing the necessary information and support to successfully deploy an OMS.

Q. Specific to Montana-Dakota, what is involved with an Outage Management System deployment?

A. The deployment plan would include an OMS software/hardware package that would add onto the company's existing SCADA/DMS software platform. In 2017, Montana-Dakota deployed a SCADA and DMS software/hardware system from Open Systems International (OSI). The new software addition to be implemented, OMS from OSI, is designed to be integrated to the existing SCADA/DMS modular system. The new software provides for the functionality of an Outage Management System. Deployment will require integration into the previously identified systems already in place at the Company, as well as field software deployed for worker interaction and communications with the new OMS system. The cost of the system additions allocated to the North Dakota Electric jurisdiction is $2,146,511 and is shown in Statement B, Schedule B-2, page 9 as PF-316300.

Additional staffing will be required to fully utilize the OMS. Additional staffing related to the implementation and ongoing utilization of the OMS are as follows:

- System Support Engineer: An Operations Technology (OT) position is required to support the software, hardware, and communications within the SCADA/DMS/OMS systems.
- System Administrator: An Information Technology (IT) position is required to support the security, user administration, and maintenance of the SCADA/DMS/OMS systems.
- System Operators: A staff of Distribution Dispatchers is required to operate a 24/7/365 Distribution Dispatch Desk within the existing Montana-Dakota Electric Systems Operations Department. Montana-Dakota has historically had decentralized dispatching within its Field Operation's District work force. A central Dispatcher for Distribution will need to be set up at Montana-Dakota to run the DMS software and interact with workers to keep the Electric Distribution Network real time with switching and Field Operations changes within the network. The Company plans to add four System Operators for this function.
- Business Analyst: This position will manage the daily operation of the OMS system, including daily outage reviews, Quality Assurance/Quality Control, data analysis, and reporting.

- Promotions: The expanded responsibilities of a central OMS deployment and staffing will require supervisory promotions within existing departments.

The labor and benefits cost related to the additional positions and promotions, allocated to the North Dakota Electric jurisdiction, equates to $176,372 in 2022 and $443,150 in 2023.

In summary, deployment at Montana-Dakota includes the software/hardware system additions, staff support additions, and a central Distribution Dispatcher incorporated into the existing operations dispatch department.

Q. What are the goals that Montana-Dakota is expecting to meet with this OMS deployment?

A. Montana-Dakota has identified four high level improvements that are expected to be achieved with the deployment of an Outage Management System.

1) Provide for an Outage Reliability Statistic and Failure/Cause Database – With the OMS based on a mapping network, the company can achieve an outage and cause database that allows information on outage reliability down to system level, device/component level, or individual customer level. This data can be used to make better decisions on system maintenance, replacements, and reliability improvements in general.

2) Provide for a Field Operations Outage Management Toolset to manage large storm events - Large Storm Events are historically difficult for a utility to manage. The OMS software and maps are expected to provide tools necessary for local Field Operations employees to track system damage, repair, and repair follow-up items in an on-line central map-based interactive format. It is expected that better and more organized response will improve outage response and a more proactive organized follow up with customer damage situations especially in the large storm events.

3) Internal Operations Outage Map and Outage Status – The OMS deployment will provide a more real time outage map for use by the Field Operations teams. With the Electric Distribution Network managed real time by a dispatcher and system information integrated into the OMS, along with interaction by Field Operations employees as to device status and outage status, all employees will have better insight into the causes of an outage and will produce a quicker and safer response to emergency and outage events.

4) Outage Information for External Customers and Reporting – The OMS will provide for better and more real time maps presenting information on outages to inform the customers involved in a power outage event. Since the OMS interacts with the Company's employees as a real time communications system for response, more information will be known about the current status of an outage and expected outage repair times that can be relayed to customers.

Q. What additional benefits are expected with the deployment of the Outage Management System including those specific to the customers?

A. There are many benefits to the Outage Management System deployment in addition to the previously stated goals. Additional benefits to the company include:

1) Providing a real time Distribution System Map to company employees as an additional safety benefit for system operations.

2) Provide 24/7/365 monitoring of the Distribution SCADA system by a system Dispatcher will provide quicker response times for abnormal events and outages.

3) Outage and reliability data can provide for better prioritization and determination of future resources to improve reliability and safety.

4) Monitoring of crew locations in an after-hours setting helps support the safety of the workers at Montana-Dakota, especially in storm related events.

More specific to the customer:

5) Improvement in overall power reliability and outage response times to customers in general.

6) Improvement in localized power reliability and outage response times due to a network, location, and individual customer level database that can be used to look beyond general response and reliability numbers to identify and address localized issues.

7) Improvement in customer communications of electric outage events. This can be in the form of maps, outage status, expected response times, IVR, news reports, social media, etc. Information will be available to customers and employees for existing outage events in a more timely and efficient manner.

8) Better information will provide the Company the opportunity to prioritize costs and resources.

Q. Would an Outage Management System have assisted Montana-Dakota during the ice storm that effected North Dakota on the weekend of April 23, 2022?

A. The Outage Management System would have provided an electronic patrol toolset for the Field Operations Group that would have allowed for the central OMS system to track damages and damage repair from the line patrols. All employees at the company would see the same map based tracking of damages, damage repair, reporting, and resolution of outages in a real time environment. Customer outages would be tracked in real time and with less confusion, since interactive outages would be seen in real time on one mapping system. Customer outage numbers would be real time and seen by all operating employees. Confusion over what areas or certain customers without power should be eliminated or greatly reduced. Follow-up work for customers with damaged facilities or after storm follow-up maintenance damages would be available to be tracked and managed after the storm event. The customer based outage map would be more accurate with less confusion over the existing outage map display. Finally, the Outage Management System would have all reliability statistics and outage information available for further review and reporting after the event.

What is the expected schedule for deploying an Outage Management System at Montana-Dakota?

A. The OMS system, including the hardware and software deployment, is expected to be installed and operating by June 2023. The additional supporting staff and Electric Distribution Dispatcher will also be in operation by mid-year 2023 to support the operations deployment of the system. It is expected that each Field Operations District will be trained and start interacting with the software and dispatcher in staged time periods. Full deployment of the system to be in full operation across the Montana-Dakota Districts will be completed by the end of the year 2023.

Q. Please explain how Montana-Dakota budgets for Capital Expenditures for Electric Distribution Transformers?

A. Montana-Dakota uses a central budget funding project for the purchasing of all Distribution Transformers for use within the Company's service territory. This funding project is forecasted and budgeted using two-year actual costs while factoring for growth and inflation. Outside of normal growth and maintenance for Electric Distribution Transformers, specific replacement projects or special project considerations have been budgeted separately in rare cases. There are no existing special case budget items currently for these units at Montana-Dakota. The Company has included plant additions $1,659,090 for 2022 and $1,696,459 for 2023 for Electric Distribution Transformers.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No. (LEK-1)

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-22-___

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. ("Montana-Dakota" or the "Company").

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), Schedule 1.

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 plant in service of the Montana-Dakota – Electric Division ("MDU" or the "Company"), as of December 31, 2020. My detailed report, including my analyses and recommendations, is provided in Exhibit No. LEK-3, titled "Calculated Annual Depreciation Rates Applicable to Plant in Service as of December 31, 2020". The detailed depreciation study report was 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. In addition, as the study was completed over the period in which COVID protocols were in place, I relied on my notes from my operational site tours from the 2018 Depreciation Study completed by Concentric. The completion of the 2018 depreciation study included tours of three Company substations and switch yards, a coal fired thermal generation plant, gas turbine generation facility, the Company service building and yard, and the MDU electric control room. Lastly, I also reviewed the average service life and net salvage indications of many North American based electric utilities to test the results of my analysis against the electric 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 electric generation, transmission, distribution and general plant assets of the MDU Electric Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2020. 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 electric assets in service, as of December 31, 2020.

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, 2017, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2018 through to December 31, 2020, 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 electric system industry, including knowledge of service life estimates used for other electric 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 $56.8 million, when applied to depreciable plant balances, as of December 31, 2020. 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	
Steam Plant	$372,470,891	2.45%	$9,115,697
Other Production Plant	$537,757,981	3.98%	$21,377,839
Transmission Plant	$522,283,617	1.70%	$8,889,889
Distribution Plant	$461,078,839	3.25%	$15,005,624
General Plant	$33,261,966	7.34%	$2,443,013
Total Plant in Service	$1,926,853,295	2.95%	$56,832,062

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 approved composite depreciation rates.

Plant Group	Proposed Depreciation Rate	Currently Approved Depreciation Rate
Steam Plant	2.45%	1.93%
Other Production Plant	3.98%	3.76%
Transmission Plant	1.70%	1.61%
Distribution Plant	3.25%	2.40%
General Plant	7.34%	5.84%
Total Plant in Service	2.95%	2.54%

Q16. Please describe the reasons for the increase in the depreciation rates related to electric production plant.

A16. The largest influence in electric production depreciation rates results from the continued use of a Life Span approach applied to each generation unit. The impact of using the Life Span approach has been more dramatic in recent years because of the large capital spending primarily related to environmental requirements at several of the units.

The use of the Life Span Method is a continuation of the method that was incorporated into the production accounts in the last depreciation study, wherein the depreciation rates for each of the location specific generation accounts were developed from the continued use of a Life Span Method. With the use of a Life Span Method, an interim retirement curve is identified for each property group, based on the analysis as described within Section 3.6 of my depreciation study report. The probable retirement dates for each of the generation plants were, provided to me by MDU, based on an internal MDU analysis of the factors impacting the terminal life of each plant. The life span date is incorporated into the interim survivor curve to develop an average service life and average remaining life, via the Life Span Method, for each of the generation accounts. A comparison of the life span dates used for each the generation facilities from the depreciation study completed in 2015 based on 2014 data and the life span dates used in my current depreciation study are provided below.

Generation Station	**Proposed**	**Currently Used**
Heskett Generating Stations (Common Plant)	N/A	2028
Lewis & Clark Generating Station (Common Plant)	N/A	2025
Coyote Generating Station	2041	2041
Big Stone Generating Station	2046	2046
Wygen III Generating Station	2060	2060
Glendive Turbine – Unit 1	2033	2022
Glendive Turbine – Unit 2	2046	2046
Miles City Turbine	2033	2019
Portable Generators	2047	2047
Heskett Turbine	2057	2057
Diamond Willow Wind Farm	2035	2027
Cedar Hills Wind Farm	2035	2030
Lewis & Clark Turbine - RICE	2045	2045
Ormat Generation Facility	2034	2029
Thunder Spirit Wind Farm I	2040	N/A
Thunder Spirit Wind Farm II	2043	N/A

These life span dates, used in my study for the MDU steam generation plants, related to several stations, are the same dates used in the last depreciation study. However, the steam generation assets at Heskett Stations I and II have been retired since the last depreciation rates were approved, leaving the common plant assets required for the support of the Turbine unit left to be depreciated. Similarly, the steam generation units at Lewis and Clark Generating Station have also retired since the last depreciation study, and again leaving the Common Assets required for the recently installed turbine unit. The use of a life span approach for these common assets at the Heskett and Lewis and Clark generating sites has been discontinued in the current depreciation study. In the Other Production category, the life span date for the Glendive Turbine - Unit 1 has been extended from December 31, 2022 to December 31, 2033, the Miles City Turbine has been extended from December 31, 2019 to December 31,2033, the Ormat Generation Facility has been extended from December 31, 2029 to December 31, 2034, the Diamond Willow Wind Farm has been extended from December 31, 2027 to December 31, 2035, and the Cedar Hill Wind Farm has been extended from 2030 to December 31 2035 . Additionally, new life span dates have been introduced for both Thunder Spirit Wind Farm units. As such, the increase in the generation depreciation rate is not significantly caused by changes in the life span dates, but rather by the large amount of capital spending that is required for the generation plants to continue to operate through to the life span date.

Over the period since the 2014 depreciation study, the gross depreciable cost related to electric generation plants that incorporate the use of a life span has increased by approximately $297 million (an increase of 48 within the steam generation capital additions, the removal of a life span from the depreciation rate calculations for the Common assets at the Heskett and Lewis and Clark generations stations has also contributed to the decrease in the depreciation rate for this segment of the generation plant.

The original cost of depreciable plant within the Other Production accounts, has increased by $331 million since 2014. This additional investment has been made in the gas turbine and renewable energy generation, representing an increase in these Other Production accounts of 160% since December 31, 2014. This investment was largely in the new Thunder Spirt Wind Farm facility - and the Lewis & Clark RICE turbine unit which account for approximately $250 million of the total $331 million of new capital investment. This new investment is subject to life span dates that are similar to the life span dates used for Other Production assets in the 2014 depreciation study, and therefore has a large impact on the depreciation rate in the Other Production category.

Q17. Please outline the reasons for the increase in the composite depreciation rate for electric transmission plant.

A17. Within the electric transmission group of assets, extensions to the average service life estimates have a decreasing impact on the transmission system depreciation rates. However, cost of removal estimates have become more negative which has an offsetting impact resulting in a small overall increase to the transmission system depreciation rates.

Q18. Please provide a summary of the current and proposed average service life estimates for transmission plant.

A18. 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 all but two accounts.

Account	**Description**	**Proposed Iowa Curves**	**Current Iowa Curves**
350.20	Land Rights	70-R4	50-R3
352.00	Structures and Improvements	50-R2	45-R2
353.00	Station Equipment	65-R2.5	60-R3
354.00	Towers and Fixtures	60-R4	55-R5

Account	Description	Proposed Iowa Curves	Current Iowa Curves
355.00	Poles and Fixtures	63-R2.5	50-R3
356.00	Overhead Conductors and Devices	70-R3	65-R3
357.00	Underground Conduit	50-R3	50-R3
358.00	Underground Conductors and Devices	50-R3	50-R3

The specific reasons for the average service life extensions for each of the large transmission 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.

Q19. Are the average service life extensions, as noted above, typical for electric transmission assets?

A19. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of electric transmission 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 transmission infrastructure. For example, in recent years electric transmission utilities have been pro-active in pole and tower structure management and adding enhanced protection and control equipment within the substations. The specific life expectation of the digital protection and control systems is shorter than the previous electro-mechanical protection and control system, however, the enhanced protection provided within the substation of the new technology has had a life extension influence for transforming and switching equipment.

Likewise, I have noted that the life of transmission line assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by electric transmission utilities. The introduction of pole and tower testing and treatments for wood structures combined with the observation of longer than previously expected life indications for steel structures throughout the industry, have provided electric transmission utilities with the ability to recognize longer lives on these transmission assets. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other electric utilities.

Q20. Please provide a summary of the current and proposed net salvage percentages for transmission plant.

A20. The following is a summary of the proposed net salvage percentages used in the depreciation rate calculations. I note that the currently approved 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. However, the following also provides a comparison of the recommended net salvage depreciation rate to the currently approved net salvage depreciation rate.

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
350.20	Land Rights	0	0.00	0.00	0.00%
352.00	Structures and Improvements	0	0.00	0.00	-2.00%
353.00	Station Equipment	-10	0.10	-10	0.15%
354.00	Towers and Fixtures	-20	0.77	-5	0.15%
355.00	Poles and Fixtures	-35	0.59	-50	1.18% 0.60%
356.00	Overhead Conductors and Devices	-20	0.46	-15	0.51%
357.00	Underground Conduit	0	0.00	0.0	0.00%
358.00	Underground Conductors and Devices	0	0.00	0.0	0.00%

(*)Rate identified in yellow represents the depreciation rate after negotiated settlement.

The specific reasons for the net salvage percentages for each of the large transmission accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical net salvage study are presented for each account, in Section 7 of my report.

Q21. Please outline the reasons for the increased composite depreciation rate for the electric distribution assets.

A21. The average service life estimates for the electric distribution assets have extended in a similar fashion as described for the average service life extensions of the electric transmission assets. However, in the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that out-weighed the influence of a decrease due to the life. 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 all but four accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
360.2	Rights of Way	62-R3	50-R2
362.00	Station Equipment	53-R2	50-R2.5
364.00	Poles, Towers & Fixtures	60-R1.5	50-R1
365.00	Overhead Conductor & Devices	65-R2	55-R1
366.00	Underground Conduit	50-R3	50-R3
367.00	Underground Conductors and Devices	42-R2.5	40-R2
368.00	Line Transformers	55-R3	55-R3
369.10	Services	50-R3	45-R3 (*)
370.00	Meters	20-L3	20-L3
371.00	Installation on Customer Premises	20-R0.5	22-R0.5
373.00	Street Lighting System	43-R1	43-R1

(*) For comparison purposes, the underground Iowa curve has been used as it accounts for the majority of the investment. The current study proposes to aggregate the overhead and underground into one depreciation rate.

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.

Q22. Are the average service life extensions, as noted above, typical for electric distribution assets?

A22. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of electric 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 electric distribution utilities have been pro-active in pole structure management and adding enhanced protection and control equipment within the substations. The specific life expectation of the digital protection and control systems is shorter than the previous electro-mechanical protection and control system, however, the enhanced protection provided within the substation of the new technology has had a life extension influence for transforming and switching equipment.

Likewise, I have noted that the life of distribution line assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by electric distribution utilities. The introduction of pole testing and treatments for wood structures have provided electric distribution utilities with the ability to recognize longer lives. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other electric utilities.

Q23. Please provide a summary of the current and proposed net salvage percentages for distribution plant.

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. However, a comparison of the recommended net salvage depreciation rates to the currently approved net salvage depreciation rate is also provided.

Account	**Description**	**Proposed**		**Last Depn Study (*)**	
		Net Salvage %	**Depn Rate**	**Net Salvage %**	**Depn Rate**
360.20	Rights of Ways	0%	0.00%	0%	0.00%
362.00	Station Equipment	(15)%	0.27%	(5)%	0.13%
364.00	Poles, Towers & Fixtures	(120)%	2.50%	(95)%	2.17% 1.50%
365.00	Overhead Conductor & Devices	(110)%	1.98%	(85)%	1.62% 1.26%
366.00	Underground Conduit	0%	-.06%	0%	-0.05%
367.00	Underground Conductor & Devices	(50)%	1.84%	(25)%	0.73% 0.33%
368.00	Line Transformers	(20)%	0.58%	(20)%	0.50% 0.25%
369.10	Services	(50)%	0.84%	(50)%	0.90% 0.23%
370.00	Meters	(5)%	0.57%	(5)%	0.46%
371.00	Installation on Customers Premises	(15)%	1.93%	(15)%	1.51%
373.00	Street Lighting System	(45)%	1.16%	(40)%	0.97%

(*)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. Five of the nine distribution accounts that had proposed cost of removal recovery in the 2015 study, now indicate the need for increased levels from the level witnessed in the 2015 study. Given the period from 2015 through 2020 has incorporated a lower than recommended rate for a number of the Depreciation accounts, this current depreciation study is proposing a significant increase in the depreciation for the company's distribution assets.

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q23. Is the trend for more negative net salvage percentage, as noted above, typical for electric distribution assets?

A23. 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 2018 Society of Depreciation Professionals conference held in September, 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.

Q24. What is causing this trend to increased cost of removal of utility assets?

A24. 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. For example, in the MDU Account 364 – Distribution Poles and Fixtures, the average service life has been extended in this study from 50 years to 60 years. Also, the last depreciation study increased the average life from 38 years to 50 years for this same account. As such, over the course of two depreciation studies, the indications of average service life have increased from 38 years to 60 years (a 58% increase). As the average service life has increased, the length of time between the original installation of the assets in this account and the estimated average time of retirement of the asset is 58% 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 58% increase in the life expectation, also results in an increased length of time that the labor associated with the removal is 58% longer. When it is considered that in this account, the impacts of inflation of an additional 22 years are recognized in the cost of removal included in my study as compared to the study completed two studies ago, and an additional 10 years when compared to the last depreciation study, it is expected and reasonable to see the increases in cost of removal. To the extent that the average service lives for distribution assets have extended, the impact as described above (for Account 364) applies to a number of the MDU electric 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 asbestos and PCB contaminants at substations 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.

III. DEPRECIATION METHODS AND PROCEDURES

Q25. How is depreciation defined for a rate regulated utility?

A25. Depreciation defined – "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric 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, wind storms, 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

1 Federal Energy Regulatory Commission, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Definitions

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.

Q26. Please outline the depreciation methods and procedures used in your depreciation study.

A26. 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.

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.

Q27. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A27. 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 was 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, 2020), 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, 2020.

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

Q28. What is your conclusion with respect to Montana-Dakota's proposed Depreciation expense?

A28. My conclusion is that Montana-Dakota's requested depreciation rates, resulting in a composite depreciation rate of 2.95%, 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 study, that I prepared for this proceeding, be adopted by the Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q29. Does this conclude your Direct Testimony?

A29. 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

- 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. 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.
- 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.
- 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)
- 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.
- 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	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066

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
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
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
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-22-___

Direct Testimony

Of

Tara R. Vesey

Q. Would you 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 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 and 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 electric operations per books cost of service for the twelve months ended December 31, 2021, and the projected cost of service for 2022 and 2023. Based on the results, I have prepared the calculation of the revenue deficiency and the calculation of the interim request. I will also discuss the Company's proposal to include the pension and post retirement benefits regulatory assets in rate base. Finally, I will discuss the amortization schedule of the Lewis & Clark Unit I and Heskett Unit I & Unit II coal regulatory assets.

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

A. I am sponsoring Statements A through D, Statement F and Statements F-2 through J, revenue requirement presented in Exhibit No.___ (TRV-1), the Company's treatment of pension regulatory asset and liability balances presented in Exhibit No.___(TRV-3), Interim Statements A through D, Interim Statement F and Interim Statements F-2 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>Case Description</u>

Q. What is included in this Revenue Requirement?

A. The Company is requesting $25,372,099, which represents a 12.3 percent increase, based on a projected 2023 test year. Montana-Dakota currently has four riders: the Generation Resource Recovery Rider (Generation Rider), the Renewable Resource Cost Adjustment (Renewable Rider), the Transmission Cost Adjustment (Transmission Rider), and the Environmental Cost Recovery Rider (Environmental Rider) (with no current recovery). The 12.3 percent increase includes the effect on the base electric rates and the Generation Rider. No changes to the Renewable and Transmission Rider are included in this request.

More specifically, Montana-Dakota is proposing to move or expand the cost recovery from certain riders and base rates as follows:

- Move the retired investment and related expenses of Lewis & Clark Unit I and Heskett Unit I and II from base retail rates to the Generation Rider.

- Move the production investment and related expenses of Lewis & Clark Unit II (RICE) currently recovered through the Generation Rider to base retail rates.
- Recover the production investment and related expenses of Heskett Unit IV in base retail rates.

Q. Why are the Renewable and Transmission Riders excluded from this case?

A. Montana-Dakota worked with the Commission to implement a smoothing effect of the Production Tax Credits (PTC's) for Thunder Spirit Wind in Case No. PU-20-440 and the Diamond Willow Wind repower project in Case No. PU-21-420. The Company will levelize the revenue to reflect a smoothing of PTCs earned over the life of those wind facilities instead of the applicable timeframe that the PTCs are earned. In an effort to provide transparency and maintain the levelization, the Company is proposing no changes to the Renewable Rider in this Case.

The Company is not proposing changes the Transmission Rider revenue requirement in base rates in an effort to simplify this filling. Given that the Transmission Rider is trued-up each year and reflects the current capital structure, the Montana-Dakota customers are not impacted by continuing the annual Transmission Rider filings.

Q. How was the $25,372,099 revenue requirement derived?

A. The Company has developed the projected revenue requirement for the 2023 test period based on projected sales revenues (including $3,450,741 associated with the Lewis & Clark RICE unit currently in the Generation Rider), Operation & Maintenance (O&M) expenses, other operating expenses, taxes and the projected 2023 rate base. In addition, Montana-Dakota is proposing to move the investment associated with the Lewis & Clark RICE unit into base rates. The result is a revenue requirement shortfall of $20,990,260.

Furthermore, Montana-Dakota is proposing to amortize $7,832,580 per year associated with the regulatory asset established upon the closure of Lewis & Clark Unit I and Hesket Unit I & II coal units and that it will be included in the Generation Rider. This proposal results in an increase to the revenue requirement of $4,381,839 when netted with the current rates under the Generation Rider.

As shown in Statement A, page 1, this results in a total change of $25,372,099.

Q. In Case No. PU-19-317, Montana-Dakota indicated the Regulatory Asset would be fully amortized in 7 years. Is that still the Company's intent?

A. In the information provided in Docket No. 66 in Case No. PU-19-317, Montana-Dakota indicated that the regulatory asset would be fully amortized over 7 years. This determination was based on a projected 2023 annual revenue requirement for Lewis & Clark Unit I and Heskett Unit I & Unit II. This determination was also based on the assumption that the Hesket Unit IV would be included in the assessment.

As previously noted, Montana-Dakota has prepared the revenue requirement to include Heskett IV in base rates. Continuing with the current level of amortization in the Generation Rider would result in an amortization period of approximately 4 years. Furthermore, customers would also not realize an offset for the Heskett IV revenue requirement. Therefore, the Company is proposing to set the revenue requirement in the Generation Rider at $7,832,580 to accomplish a 10-year amortization and, as noted by Ms. Kivisto, to somewhat mitigate the rate increases to customers as a result of this filing.

The amortization period began in April 2021 and is expected to be completed in April 2031.

<u>Revenue Requirement</u>

Q. What were the results of North Dakota electric operations for 2021?

A. Statement A, pages 3 and 4 show the per books income statement and rate base for the North Dakota electric operations for 2021. As shown on page 3, North Dakota electric operations produced a return on rate base of 5.942 percent for the twelve months ended December 31, 2021. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the referenced Statements.

Montana-Dakota prepared an Adjusted 2021 calculation that reflects the Per Books 2021 income statement and rate base excluding the Renewable Rider, the Transmission Rider, and the production investment and related expenses of Lewis & Clark Unit I and Heskett Unit I and II. The resulting statement present a similar comparison to Projected 2022 and 2023.

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 2023 test period. As stated by Ms. Kivisto, the revenue increase is largely driven by:

	Amount (in millions)
Increase in Rate Base	$13.8
Lower Sales	2.7
Higher O&M Expenses	10.0
Higher Depreciation	10.0
Property Tax	1.7
Other	1.0
Amortization of L&C and Heskett	7.8
Offset by:	
L&C and Heskett Savings	($21.6)
Net Increase	$25.4

The Heskett Unit IV addition is included in the Rate Base and represents approximately $5.6 million of the $13.8 million increase. The effect of the depreciation study is approximately $4.6 million of the depreciation increase.

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 2022 and 2023?**

A. The projected 2022 and 2023 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 2022 and 2023. Likewise, the rate base reflects average 2022 and 2023 plant and related balances.

Income Statement

Q. **Would you describe the development of the projected revenues and expenses?**

A. The projected revenues for 2022 and 2023 are summarized in Statement F. Mr. Neigum discusses the development of the projected volumes in his testimony, and Ms. Bosch discusses the development of the retail sales revenues in her testimony.

Revenue and expenses were developed to include:

- Base rates and the movement of the current Generation Rider (based on the Lewis & Clark RICE unit) into the base rates
- Include the Heskett IV plant addition
- Exclude the amortization of the Lewis & Clark Unit I and Heskett Unit I & Unit II

As noted earlier, the Renewable Rider and Transmission Rider were not included in the development of the revenue or expense and each will be discussed individually.

Base Rates: The projected base revenues for 2022 and 2023 are summarized on Statement F, page 1. The retail sales revenues reflect projected volumes at current rates, including the Generation Rider (currently including the Lewis & Clark RICE unit), again at current rates, and are shown in more detail on Statement F, Schedule F-1, page 1.

The Company did report sales for resale revenue in 2021. Montana-Dakota continues to propose that revenue from sales for resale offset the costs included in the fuel and purchased power adjustment and, therefore, no projection has been included.

Other operating revenues are projected to decrease as detailed on Statement F, Schedule F-1, page 1 primarily because the Company continues to propose that revenue from the sale of renewable energy credits (RECs) offset the costs included in the fuel and purchased power adjustment and, therefore, are excluded from Miscellaneous Revenue.

Late payment revenues were projected for 2022 and 2023 based on the 2021 ratio of late payment revenue to retail sales revenue of 0.103 percent applied to Projected 2022 and 2023 retail sales revenue excluding the projected revenue from the Renewable and Transmission Riders.

Heskett IV Plant Addition: The plant addition and associated depreciation, taxes, and operation and maintenance (O&M) expenses are included in the Rate Base and Income Statement in Projected 2023. The Company has proposed to include the asset as if it had been in service for all of 2023. Other assets placed in service during 2023 are assumed to have a mid-year in service date. With that in mind, Heskett IV will reflect a full annual period of depreciation and the full in service cost for the test year 2023. Because of the significant level of capital investment in Heskett IV, the revenue requirement would be significantly under stated for all periods following the implementation of rates and could impact the Company's ability to earn a reasonable rate of return resulting in a follow up rate case.

Amortization of Lewis & Clark Unit I and Heskett Unit I & Unit II: The amortization of the of Lewis & Clark Unit I and Heskett Unit I & Unit II is currently a component of base rates and the Company proposes to move recovery to the Generation Rider. Although Lewis & Clark did operate during 2021 and Heskett operated for all of 2021 and the beginning of 2022, all associated revenue and expenses have been excluded from the Adjusted 2021 and Projected 2022 and 2023 periods.

Renewable and Transmission Rider: As previously discussed, the associated revenue and expenses of the Renewable and Transmission Riders have been excluded.

Q. Would you describe the development of the operation and maintenance expenses?

A. Yes. The projected 2022 and 2023 O&M expenses are summarized on Statement G, Schedule G-1, pages 5 through 8, with the detail provided on pages 9 through 31.

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 on a North Dakota electric basis. As stated previously, Montana-Dakota created an Adjusted 2021 calculation that reflects the Per Books 2021 values and excludes the Renewable Rider, the Transmission Rider, and the production investment and related expenses of Lewis & Clark Unit I and Heskett Unit I and II.

Montana-Dakota developed the O&M expenses for 2022 by by reviewing current information, as well as discussions with operations personnel to determine the best information for 2022 excluding the current Renewable and Transmission Riders and the Lewis & Clark Unit I and Heskett Unit I & Unit II which will be moving to the Generation Rider. Projected 2023 expenses are based on Projected 2022 expenses with the Company's best estimate when changes are known or based on an inflation factor when appropriate. To establish an inflation factor, the Company based its factor on the indices published by the Organization for Economic Cooperation and Development, International Monetary Fund, and PriceWaterhouseCoopers. The rates are represented in an average of 3.37 percent for 2022 and 2.56 percent for 2023.

Q. Have you updated the fuel and purchased power costs?

A. Yes. The fuel and purchased power cost adjustment has been included on Statement G, Schedule G-1, page 9. The Company's dispatching software has been updated to model generation by plant based on the projected sales adjusted for losses to represent total generation and power purchase requirements and has been updated to reflect projected cost assumptions and purchased power prices. The fuel and purchased power cost adjustment has been computed in total and has been allocated to both primary and secondary sales classes for the purposes of determining the recovery in revenue on a per unit basis.

As shown on Statement Workpapers G, Schedule G-1, page 2, the cost per kWh is projected to reduce for Montana-Dakota customers from Per Books 2021 to the Projected 2022 and 2023 periods.

Q. Would you describe the development of the labor and benefits expense?

A. Yes. Labor expense is shown on Schedule G-1, page 10, with actual labor expense for the twelve months ended December 31, 2021 used as the starting point, with the Adjusted 2021 value (excluding the Renewable Rider and Lewis & Clark Unit I and Heskett Unit I & Unit II) defined on page 11.

Montana-Dakota expects to hire 12.81 full time employees to its Customer Experience Team as replacements for annualized employee turnover in 2021. Furthermore, as described in detail by Mr. Anderson, an Outage Management Software will be implemented which will require additional employees. These replacement or new positions and the labor expenses associated are further defined in pages 12 through 13.

The overall projected increase of 3.32 percent in 2022 includes an increase of 3.00 percent for bargaining unit employees pursuant to a negotiated union contract and 3.50 percent for non-bargaining unit employees effective in 2022. Incentive compensation has been adjusted to reflect 11.65% of straight time and vacation. The overall increase for projected 2023 is 3.97 percent and includes an increase of 3.00 percent for bargaining unit employees pursuant to a negotiated union contract and 4.50 percent for non-bargaining unit employees.

Benefits are shown on Schedule G-1, page 14 with additional support provided on pages 15 through 17. Benefits expense consists of medical/dental insurance, pension, post-retirement, 401K, and workers compensation. Each of these items was adjusted individually. Medical/dental expense for 2022 and 2023 reflect an increase of 10.00 percent per year based on premiums in effect for 2022. Pension and post-retirement expense for 2022 and 2023 is based on the 2022 Actuarial

Estimate. Projected 401K, workers compensation, and other benefits expense reflected the straight time labor increase of 3.32 percent for 2022 and 3.97 percent for 2023. Pages 16 through 17 represent the additional benefits associated with the new or replacement positions referenced above.

Q. Would you describe the other projected O&M expense items

A. Yes. The subcontract labor expense shown on Statement G, Schedule G-1, page 18 is based on the Adjusted 2021 value, adjusted for a budgeted building and grounds project for maintenance to the outside of the General Office Building, and inflated 3.37 percent for 2022 and 2.56 percent for 2023 based on an average of the three indices described above.

Big Stone and Coyote expenses shown on Statement G, Schedule G-1, page 19 are based on 2021 actual expenses. Projected 2022 and 2023 were adjusted to reflect expected cost of operation for 2022 and 2023 with normalized outages scheduled.

Materials expense, shown on Statement G, Schedule G-1, page 20, reflects the Adjusted 2021 value with an increase of 10.00 percent for 2022 and 5.00 percent for projected 2023. Projected 2022 also considers current pricing trends while 2023 reflects the material expense associated with the implementation of Hesket Unit IV.

Vehicles and work equipment shown on Statement G, Schedule G-1, page 21 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. Projected 2022 and 2023 is based on projected plant applied to proposed depreciation rates and projected fuel expenses based on U.S Energy Information Administration Short-Term Energy Outlook.

Company utilities shown on Statement G, Schedule G-1, page 22 is the expense for general utilities, electric, and natural gas consumption in Company buildings. The general utilities and electric components are based on a three-year average annual expense of 2018, 2019, and 2021. The Company excluded 2020 as the expense was abnormally low to most employees working from home as a result of the COVID-19 pandemic.

The natural gas component is based on 2021 weather normalized volumes and increased projected cost of natural gas and propane.

Uncollectible accounts expense shown on Statement G, Schedule G-1, page 23 is based on the ratio of the five-year average of net write-offs to sales revenue. This ratio was then applied to the projected 2022 and 2023 sales revenues, which results in an increase in uncollectible accounts expense.

Postage expense shown on Statement G, Schedule G-1, page 24 for projected 2022 reflects the 4.45 percent postage increase for 2022. Conversely, the additional postage savings for the year is calculated by considering the number of customers receiving their monthly billing via electronic format as of the December 2021. Postage expense for 2023 is projected to increase by the 2.56 percent inflation rate.

Software maintenance expense shown on Statement G, Schedule G-1, page 25 is based on estimated levels for projected 2022. The costs associated with 2023 are based on the five-year average increase of expense and reflect expenses related to a variety of areas including those mandated cybersecurity needs. Advertising expense is shown on Statement G, Schedule G-1, page 26. Promotional advertising expense has been eliminated from the projected time periods and informational and institutional advertising are adjusted to exclude advertising that is not applicable to North Dakota electric operations. Additionally, Projected 2022 and 2023 reflect an inflation rate of 3.37 percent and 2.56 percent, respectively.

Industry dues shown on Statement G, Schedule G-1, page 27 reflect the projected levels of industry dues and eliminated the industry dues not specifically applicable to North Dakota electric operations.

Insurance expense shown on Statement G, Schedule G-1, page 28 reflects projected 2022 at the current insurance level as of January 2022. Projected 2023 reflects an increase of 10.00 percent based on recent trends and additional insurance expenses associated with Heskett Unit IV.

Regulatory commission expense as shown on Statement G, Schedule G-1, page 29 reflects the expenses to be incurred in this filing amortized over a three-year period, a three-year average of ongoing regulatory commission expense, and the expenses related to the common and electric depreciation studies amortized over five years for projected 2022 and 2023.

Covid expense as shown on Statement G, Schedule G-1, page 30 reflects a normalizing adjustment to reflect those costs that were avoided or delayed during the COVID-19 pandemic. Costs associated with external auditing, collection agency fees, commercial and corporate air, personal vehicle usage, office supplies, safety training materials and expenses, and other reimbursable expenses were normalized using a 2016 through 2019 averages and applied to the Adjusted 2021 calculation. Projected 2022 and 2023 also reflects inflation rates of 3.37 percent and 2.56 percent, respectively.

The O&M expenses adjusted individually above represent approximately 96.5 percent of total North Dakota electric O&M expenses, as shown on Statement G, Schedule G-1, pages 1 and 2. The remaining O&M expenses, which make up approximately 3.5 percent of other O&M expenses, were adjusted by 3.37 percent and 2.56 percent to reflect the effects of inflation for projected 2022 and 2023.

Q. Would you describe the calculation of depreciation expense?

A. The depreciation rates in this filing are proposed based on a depreciation study prepared by Concentric Energy Advisors at the Company's request as of December 31, 2020. These rates represent an increase in depreciation expense and are fully explained by Mr. Kennedy. As noted on page 18, lines 4 through 7 of his Direct Testimony, Mr. Kennedy states:

"Given the period from 2015 through 2020 has incorporated a lower than recommended rate for a number of the Depreciation accounts, this current depreciation study is proposing a significant increase in the depreciation for the company's distribution assets."

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 and 2. The summary of composite depreciation rates is shown on Statement H, Schedule H-1, page 1.

Q. How were taxes other than income projected?

A. Projected taxes other than income are shown on Statement I. As shown on Statement I, Schedule I-1, page 1, Ad valorem taxes were calculated using the projected 2022 and 2023 average plant in service balances (excluding the Transmission and Renewable Riders, and the Lewis & Clark Unit I and Heskett Unit 1 & Unit II) and applying the effective tax rate based on the ratio of the Adjusted 2021 ad valorem taxes to the Adjusted 2021 plant balances, by function.

Projected payroll taxes were based on the ratio of payroll taxes to labor expense for 2021 and applied to the projected 2022 and 2023 labor expense to determine the projected payroll taxes as shown on Statement I, Schedule I-1, page 2.

Production taxes have been adjusted to reflect 2022 and 2023 projected generation levels and applicable retail sales volumes. North Dakota coal conversion taxes have also been adjusted to reflect projected generation levels. Wind Generation Tax has been removed as it is recovered in the Renewable Rider.

All other taxes other than income were projected to remain at the 2021 level.

Q. Would you describe the calculation of federal and state income taxes?

A. The projected income tax calculation for North Dakota electric operations is shown on 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 using the projected debt ratio and weighted cost of debt from Statement E, page 1.

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.

Rate Base

Q. Would you describe the development of the projected rate base for 2022 and 2023?

A. The rate base is summarized on Statement A, page 4 and shows the Per Books 2021, Adjusted 2021, and projected 2022 and 2023 average rate base for North Dakota electric operations. Statements B, C, D, and J are the supporting components of the projected rate base.

Statement B, page 1 shows the projected plant in service for 2022 and 2023. The projected plant was developed by adding the capital budget items for 2022 to the Adjusted 2021 plant in service balances. The projected 2022 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 2022 balance was calculated. The process was repeated for 2023 in detail on Statement B, Schedule B-1, page 2 with the only difference being Hesket Unit IV is recorded at a full year value. Statement B, Schedule B-1, pages 3 through 8 detail the 2021

Adjusted Plant in Service associated with the North Dakota electric operations.

The detailed capital additions by project for 2022 and 2023 are shown on Statement B, Schedule B-2, pages 1 through 11. These additions exclude any items that are included in the Transmission and Renewable Rider. Because the Lewis & Clark Unit I and Heskett Unit I & Unit II are being retired, there are no capital additions related to these coal units, except for those associated with landfill closures. Page 11 specifically references the addition and associated depreciation, and taxes associated with Heskett Unit IV.

The projected accumulated reserve for depreciation is summarized in Statement C. The projected reserve balances were calculated using the Adjusted reserve balances as of December 31, 2021, 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 and 2. The average 2022 balances were then calculated and the process was repeated for 2023 with the only difference being Hesket Unit IV is recorded at a full year value.

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 Statement D, Schedule D-1, pages 1 through 12. Materials and supplies, fuel stocks, and prepaid insurance were restated to a thirteen-month average on pages 1, 2, and 3, reflecting actual balances through December 2021 with January 2022 through December 2023 based on the prior period actual results. For fuel stocks, the prior period results used to project January 2022 through December 2023 were excluding those costs associated with Lewis & Clark Unit I and Heskett Unit I & Unit II.

The unamortized loss on debt, unamortized redemption of preferred stock cost, loss on the sale of buildings, and decommissioning of retired power plants were calculated using the balance as of December 31, 2021 and adding the calculated change for 2022, which reflects a reallocation of the balance and the annual amortization, to arrive at a balance for 2022. The 2021 and 2022 balances were then averaged to reflect the 2022 average. The process was repeated to calculate the 2023 average, as shown on Schedule D-1, page 4, 5, 6 and 9. The associated accumulated deferred income taxes for unamortized loss on debt were also included.

The loss on the sale of buildings is being amortized over a 20-year period. The decommissioning of retired power plants was fully amortized in 2021.

The regulatory asset associated with Lewis & Clark Unit I and Heskett Unit I & Unit II is shown on Statement D, Schedule D-1, page 11 through December 2022 assuming the proposed 10-year amortization. Effective with the implementation of final rates from this Case, the Company is proposing this regulatory asset be recovered through the Generation Rider.

The regulatory liability associated with the Renewable Rider is shown on Statement D, Schedule D-1, page 12 and is excluded from this case, it is only reflected in the Per Books 2021.

Customer advances for construction are shown on Statement D, Schedule D-1, page 10 and have been restated to a thirteen-month average balance for 2022 and 2023, with actuals through December 2021.

The Company is also proposing to include the provision for pensions and benefits and post retirement in the revenue requirement for the 2023. The associated accumulated deferred income taxes were also included and is discussed in detail below. The inclusion of these regulatory assets is consistent with the treatment in the most recent gas rate case (Case No. PU-20-379).

Q. Montana-Dakota has proposed to include the net pension regulatory asset in rate base. Will you explain why?

A. Yes. As discussed in the testimony of Ms. Kivisto, the Company's required contributions to the pension account resulted in a significant prepaid asset and exceeded the amount of pension expense (commonly referred to as FAS 87 or ASC 715 expense) recovered through the revenue requirement. The contributions are tax deductible for Montana-Dakota and any earnings on those contributions in the pension trust account are not subject to income tax. With that in mind, the contributions help maintain the required funding level and, at the same time, typically result in lower FAS 87 expense.

Post retirement contributions are typically much more closely matched to the annual expense, so the prepaid asset is much smaller. However, Montana-Dakota considers the benefits and the circumstances surrounding the creation of both prepaid assets or liabilities that it is appropriate to include both pension and post retirement similarly.

The table below presents the regulatory asset or liability position for Montana-Dakota beginning in December 2004 through December 2021.

As shown, Montana-Dakota has made cash contributions in the amount of $81.5 million but has recovered only $28.7 million through the inclusion of pension expense in the revenue requirement. North Dakota electric operations' share of the total pension regulatory asset is $15.7 million as of December 31, 2023.

	Cash Contributions	Pension Expense	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj. 3/	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Activity - 2020		(177,300)	59,934,780
Activity - 2021		(727,718)	60,662,498
Total Funding	$81,544,704	$28,659,472	
Ending Balance - 12/31/2021			$ 60,662,498

Q. Is Montana-Dakota required to make contributions to its pension trust fund? And what are the ramifications if funding is not maintained?

A. Yes. Internal Revenue Service rules govern minimum required pension funding contributions. If required contributions are missed or delayed, the missed payment would be considered a reportable event under the Employee Retirement Income Security Act of 1974 (ERISA) rules. This could also subject the Company to excise taxes for failure to meet minimum funding requirements. In addition, if the funded status drops below certain levels, restrictions on benefit payments may be required as well as potentially increased premiums payable to the Pension Benefit Guaranty Corporation.

Q. Montana-Dakota has included pension and post-retirement benefits in this filing. Will you explain why the Company has decided to include these regulatory assets in rate base at this time?

A. As reflected in the table above, the pension regulatory asset fluctuates from an asset to a liability and then, beginning in 2012, started to increase to a magnitude as the Company had made significant funding contributions. However, the amount recovered through the revenue requirement (i.e. recovery of FAS 87 expense as a component of operating expenses) has decreased to the point that the regulatory asset has become a material asset upon which Montana-Dakota is not able to earn a return. The Company was evaluating the inclusion of pension and post retirement at the time of the last electric rate case (Case No. PU-16-666) but did not include the regulatory assets at that time. Since that time, Montana-Dakota did propose the inclusion of pension and benefits and post-retirement benefits regulatory assets in gas Case No. PU-20-379 rate base. The Company's proposal was accepted by the Commission through the Settlement Agreement in that Case.

Post retirement benefits regulatory assets are similar in nature, as mentioned earlier, but is on a smaller scale.

Q. Please describe Exhibit No.__(TRV-3).

A. Exhibit No.__(TRV-3) was prepared to present the Company's general ledger treatment and to provide a historic view of the pension regulatory asset and liability balances.

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 2022 and 2023 to the Adjusted 2021 balances and calculating the average balance.

The changes associated with book/tax depreciation differences (liberalized depreciation and full normalization,) are on Schedule J-2, page 3 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.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Statement A, pages 1 and 2, shows the calculation of the revenue deficiency of $25,372,099 based on the projected 2023 income and rate base and using the overall rate of return of 7.513 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 and interim revenue requirement, presented in Exhibit No.___(TRV-2) of $11,422,625 and Statement A of the Interim Application based on the 2023 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:

- The depreciation rates were modified to reflect the currently approved deprecation rates as approved in Case No. PU-16-666;
- The investment associated with Heskett Unit IV and the associated depreciation;
- The Return on Equity (ROE) was modified to reflect the 9.650 percent authorized in Case No. PU-16-666;
- The pension and benefits and post retirement regulatory assets were excluded; and
- The annualized amortization of the Lewis & Clark Unit I and Heskett Unit I & Unit II was adjusted to reflect a 10-year amortization and the regulatory

asset was included in the working capital. The Company is proposing to reduce the current amortization upon the implementation of the interim rates to match the proposed revenue requirement.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2023

	BASE RATES AND RIDERS					
	2023 Revenue at Current Rates	Move Generation (RICE) to Base	Move L&C UI and Heskett UI&II to Generation	Revenue Increase at 10.5% ROE	Total 2023 Revenue Requirement	Total Change in Revenue Requirement
Base Retail Rates	$169,452,236	$3,450,741	$0	$17,539,519	$190,442,496	$20,990,260
Riders:						
Generation	$3,450,741	-$3,450,741	$7,832,580	$0	$7,832,580	$4,381,839
Renewable	18,146,907				18,146,907	
Transmission	14,707,614				14,707,614	
Total Revenue	$205,757,498	$0	$7,832,580	$17,539,519	$231,129,597	**$25,372,099**

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2023

BASE RATES	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$172,902,977	**$17,539,519**	$190,442,496
Sales for Resale	-		-
Other	3,898,165		3,898,165
Total Revenues	176,801,142	17,539,519	194,340,661
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	45,814,244		45,814,244
Other O&M	55,764,922		55,764,922
Total O&M	101,579,166		101,579,166
Depreciation	30,209,497		30,209,497
Taxes Other Than Income	7,356,417		7,356,417
Current Income Taxes	4,922,147	4,280,502 2/	9,202,649
Deferred Income Taxes	0		-
Total Expenses	144,067,227	4,280,502	148,347,729
Operating Income	$32,733,915	$13,259,017	$45,992,932
Rate Base	$612,177,981		$612,177,981
Rate of Return	**5.347%**		**7.513%**

1/ See Statement A, Page 3.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS - INTERIM
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2023

	BASE RATES		
	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$172,902,977	**$11,422,625**	$184,325,602
Sales for Resale	-		-
Other	3,898,165		3,898,165
Total Revenues	176,801,142	11,422,625	188,223,767
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	45,814,244		45,814,244
Other O&M	55,501,290		55,501,290
Total O&M	101,315,534		101,315,534
Depreciation	28,738,721		28,738,721
Taxes Other Than Income	7,063,612		7,063,612
Current Income Taxes	5,453,163	2,787,680 2/	8,240,843
Deferred Income Taxes	0		-
Total Expenses	142,571,030	2,787,680	145,358,710
Operating Income	$34,230,112	$8,634,945	$42,865,057
Rate Base	$605,353,152		$605,353,152
Rate of Return	**5.655%**		**7.081%**

1/ See Statement A, Page 2.
2/ Reflects state and federal taxes at 24.4049%.

MONTANA-DAKOTA UTILITIES CO.
PENSION & BENEFITS EXHIBIT
2017 - 2021
(000s)

GENERAL LEDGER RECONCILATION

	2017	2018	2019	2020	2021
Fair Value of Net Plan Assets	$192,712	$167,331	$176,548	$184,031	$178,442
Benefit Obligation at End of Year	250,889	219,969	206,730	212,723	199,426
Funded Status - Over (Under)	($58,177)	($52,638)	($30,182)	($28,692)	($20,984)
Regulatory Asset	$102,514	$103,455	$89,939	88626	81646
Net Asset in Rate Base	$44,337	$50,817	$59,757	$59,934	$60,662

MONTANA-DAKOTA UTILITIES CO.
PENSION BALANCE SUMMARY
ENDING DECEMBER 31, 2021

	Cash Contributions 1/	Pension Expense 2/	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
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Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
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Activity - 2019	15,452,375	1,379,116	59,757,480
Activity - 2020		(177,300)	59,934,780
Activity - 2021		(727,718)	60,662,498
Total Funding	$81,544,704	$28,659,472	
Ending Balance - 12/31/2021			$ 60,662,498

1/ Actuarially determined cash payments to the pension trust fund.
2/ Actuarially determined pension expense use in the development of the revenue requirement through rate cases.
3/ Adjustment to reflect the removal of MDU Resources pension funding - cash received by Montana-Dakota due to the 1/1/2019 corporate reorganization in Case No. PU-18-075.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-22-___

Direct Testimony

of

Ronald J. Amen

May 16, 2022

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 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

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, distributed generation, 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 rate 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 both 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 25 years of which have been in the field of 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 issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and 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 Appendix A.

Q. Have you previously testified before the North Dakota Public Service Commission ("Commission")?

A. Yes. I provided expert witness testimony on behalf of Montana-Dakota in Case No. PU-20-379.

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 rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Principles of Cost Allocation
- The Cost of Service Process
- Selection of Class Cost of Service for Montana-Dakota
- 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), Overall Bill Impact
- Exhibit No.____(RJA-2), Estimated Residential Bill Increases

II. COST OF SERVICE STUDIES

Q. What are the purposes of cost of service studies?

A. The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. In other words, a cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

The cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. The cost analyst must rely on who causes costs and how those costs are recovered within a class of customers as the basis for determining rates that result from the cost of service study.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

III. PRINCIPLES OF COST CAUSATION

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool of ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," which is another way of saying those who cause the costs should pay the costs. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term "on average" is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for "typical" customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods
2. Non-Coincident Peak ("NCP") Methods
3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

<u>Table 1</u>

<u>Cost Allocation Methods Summary</u>

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the Montana-Dakota cost of service study?

A. A combination of a) the 12-CP demand method for production and transmission costs, and b) the class NCP demands at the generation and distribution levels were used in developing the Montana-Dakota COSS.

Q. Is there a test or analysis used in the utility industry to determine the appropriateness of the allocation method for production and transmission assets?

A. Yes. The Federal Energy Regulatory Commission ("FERC"), the body that regulates the wholesale rates of electricity in interstate commerce, has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[1] FERC will

[1] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

allow utilities to propose an alternative to 12 CP, but the utility must demonstrate that such alternative is consistent with the utility's system planning and would not result in an over-collection of the utility's revenue requirement. In evaluating such determinations, FERC uses the three peak ratios test established in *Golden Spread Electric Coop., Inc.*, 123 FERC ¶ 61,047 at 61,249 (2008):

Test No. 1 – On and Off-Peak Test: This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

Test No. 2 – Low-to-Annual Peak Test: Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

Test No. 3 – Average to Annual Peak Test: Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.

I applied FERC's three peak ratios test to Montana-Dakota's North Dakota load data (2014-2021). Montana-Dakota meets all three FERC tests for using 12 CP for five out of the eight years. For 2015 and 2020 Montana-Dakota meets two of the three tests, and for 2016 Montana-Dakota meets one of the three tests. Therefore, based on the FERC three peak ratio test, it is appropriate to use the 12 CP allocation method for production and transmission demand-related costs on Montana-Dakota system. Table 2 below shows the results of the Montana-Dakota's FERC 12-CP test.

Table 2

FERC 12-CP Tests*

Use 12 CP if:	Peak - Off-Peak % Difference <=19.0%	Low/Annual Peak Ratio >=66.0%	Avg/Annual Peak Ratio >=81.0%
2021	17.6%	68.2%	83.8%
2020	18.2%	62.5%	84.1%
2019	12.9%	74.5%	89.5%
2018	16.2%	72.0%	86.8%
2017	15.0%	67.0%	85.9%
2016	19.2%	65.0%	84.0%
2015	16.7%	65.1%	83.8%
2014	12.0%	72.6%	83.5%

*Per 123 FERC ¶ 61,047 at 61,249

IV. THE COST OF SERVICE STUDY PROCESS

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution
- General, Common, and Intangible

Each of these functions is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly, plant and expenses caused by individual customers.

The General, Common, and Intangible function includes office buildings and equipment, vehicles, materials and supplies, the Customer Care and Billing (CC&B) system, and other engineering and communications software systems.

Q. Please describe the cost classification step?

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand related and the portion that is customer related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. *Demand* costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes. For example, as mentioned earlier, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process?

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and is adjusted to equal system peaks. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors.

Q. How do the principles and processes you have explained pertain to fixed costs and variable costs?

A. In the utility ratemaking context, fixed costs include all costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

V. SELECTION OF CLASS COST OF SERVICE FOR MONTANA-DAKOTA

A. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant.

A. The Montana-Dakota system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity. For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer.

Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. When customers who have common load characteristics, "homogeneous" load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 (Poles, Towers & Fixtures), 365 (Overhead Conductor), 367 (Underground Conductor), 368 (Line Transformers), 369 (Services), 370 (Meters), and 373 (Street Lighting), either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customer's own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The concept of a minimum system assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

B. Minimum Distribution System

Q. Is the method used by the Company to determine a customer cost component of a distribution system a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-size unit of plant investment. The zero-intercept method determines the costs associated with zero loads by valuing the costs of all assets in an account and conducting regression analysis of cost on current-carrying capacity or demand rating to establish the cost of a zero-load system. The most commonly installed, minimum-sized unit of plant method classifies the costs of a hypothetical minimum-size version of the utility's distribution system capable of connecting to all customers as customer-related, then classifies all remaining costs as demand-related. Each of the accounts (e.g., Account Nos. 364 – 367) are examined to identify the smallest, most commonly used type of pole, conductor, etc.. The unit cost of this minimum-size plant is then multiplied by the total number of units of that plant type. A comparison with the value of all the assets in the account yields the minimum-sized result. Both methods are acceptable to the industry. One of the more commonly accepted literary references relied upon when preparing embedded cost of service studies is the <u>Electric Utility Cost Allocation Manual</u>, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC").

Q. Of the two methods, which has Montana-Dakota used to determine its minimum distribution system?

A. Montana-Dakota uses the minimum-size method for Account Nos. 364 – 367 and the zero-intercept method to classify transformers (Account 368). The Company's method for Account Nos. 364 – 367 uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. This approach has been used by Montana-Dakota in prior COSS studies in North Dakota and its other jurisdictions.

Q. Does the one-mile minimum system approach a provide a reasonable representation of customer-driven distribution system costs?

A. Yes. The one-mile-of-circuit approach attempts to construct a realistic representation of a Montana-Dakota circuit under two scenarios and applies the standard minimum system logic that uses the smallest feasible equipment size to serve that circuit as an acceptable way to identify customer-driven cost. Montana-Dakota's approach of creating a hypothetical one-mile circuit is a realistic proxy for circuits in Montana-Dakota's service territory.

Q. How does Montana-Dakota apply the one-mile minimum system methodology in its COSS study?

A. Montana-Dakota combines its customer and demand portions of Account Nos. 364-367 based on weighted asset values for each account to derive single percentages for the combined accounts.

Q. How does Montana-Dakota separate the two classification components for Account No. 368, line transformers?

A. Montana-Dakota uses the zero-intercept approach for each of three types of transformers (single-phase and three-phase pad mount transformers, and single-phase line transformers).[2] The weighted average of the three types yields the two classification components for the complete account.

[2] In each case, the analysis makes use of the transformers that are both currently in use and likely to be reordered as replacements for aging line transformers to determine the zero-intercept value and then uses the entire asset base to calculate shares. This technical detail is adopted to avoid the need to develop replacement prices for transformer sizes that are not going to be reordered at the time that existing transformers of those sizes are to be replaced.

Q. Why does Montana-Dakota use the zero-intercept method for Account No. 368, but the minimum-size method for the other accounts described above?

A. Line transformers are not readily included in the methodology based on the representative one mile of circuit. Line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis.

The results of Montana-Dakota's analyses appear in the **Table 3** below. The values for the weighted average of FERC accounts 364-367 and FERC account 368 are inputs to the COS model. Note that, as with other utilities, FERC account 366, underground conduit, is assumed to have the same classification properties as underground conductors.

Table 3

Minimum Size/Minimum Intercept Results

FERC A/C	Account Name	Customer	Demand
364	Poles – Primary	70.9%	29.1%
365	Overhead Conductors	92.4%	7.6%
367	Underground Conductors	85.9%	14.1%
364-367	Weighted Average	83.4%	16.60%
368	Line Transformers	64.1%	35.9%

C. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer related, all of the associated

O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores, tools, and equipment. Fourth, a portion of administrative and general expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

D. Distribution Plant

Q. What method does Montana-Dakota employ to allocate demand-related distribution costs?

A. Montana-Dakota allocates demand-related distribution costs primarily by reference to class shares of noncoincident peak ("NCP") demand. Load research reveals each class's single maximum level of consumption over the course of a year. The "One NCP" allocator is simply each class's share of the sum of these values. (The "One" signifies a single annual maximum value.) Investment in distribution costs occurs in response to the increase in peak demands of customers on individual feeder lines, such peak demands not necessarily corresponding in timing to system peak demands. Accordingly, measuring each customer class's peak and then estimating the class's share in the sum of the peaks across all classes, is a reasonable way to judge responsibility for demand-related cost causation applying to distribution investment.

The Montana-Dakota COSS model uses two NCP allocators, one applicable at the generation level and another at the secondary service level. The “NCP – Generation Level” allocator is based on the peak demands of all customers and allocates demand related costs associated with land, station equipment, poles, conductors, and conduit. The “NCP – Secondary Level” allocator is based on the peak demands of secondary distribution customers and allocates demand-related line transformer costs.

Q. What is the underlying evidentiary basis for Montana-Dakota’s One NCP allocators?

A. Montana-Dakota has developed load research data for its customer classes. For each class, Montana-Dakota developed sample usage, coincident peak, and class non-coincident peak data for calendar 2019, then scaled the values based on billed kWh. This results in demand values that preserve observed load factors of the load research sample. Load research results are available to Montana-Dakota for about 93% of jurisdictional load. The classes making up the remaining 7% of load were each matched to a class for which interval data are available. Demand values were calculated that produce load factors identical to the class with which each class lacking interval data was matched. For the test year (2023), Montana-Dakota produced kWh forecasts and demand values that yielded load factors identical to those of the historical data.

Q. In your opinion is Montana-Dakota’s load research process reasonable?

A. Yes. This application of load research data to generate demand-related allocators is standard practice; it is consistent with other utilities' practices.

Q. How does Montana-Dakota allocate customer-related distribution costs?

A. Montana-Dakota uses allocators based on customer numbers, weighted by costs for certain cost categories, for various types of assets and expenses. The Company develops several customer-related allocation factors: customer numbers; customer less outdoor lighting; customer meters, weighted by an index of meter costs; customer service drops, weighted by service cost; customer transformers, weighted by transformer cost; and customer accounts, weighted by the cost of customer support. The Company's forecasts of test year customer numbers and meter numbers underpin these allocation factors.

E. Other Allocation Factors

Q. Please describe other types of allocation factors within the COSS.

A. There are numerous other allocation factors in the COSS. Fuel and purchased power expenses are allocated on energy at generation as are certain fuel related O&M costs. Purchased power capacity also has a demand component, which is allocated on 12-CP. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, rate base items like provision for pension and benefits and post retirement are allocated on O&M excluding fuel and purchased power. General, Common, and intangible plant investments are allocated on Production, Transmission and Distribution plant. General, Common-Intangible-CC&B and PCAD are allocated on Total Customers.

F. Summary of the Allocated Cost of Service Study

Q. Please summarize the results of the recommended cost of service study.

A. The following Table 4 provides a high-level summary of the results of the COSS. Table 4 shows the rate of return for each rate class based on current rates as well as the system overall return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

Table 4

Rate of Return and Revenue Excess/(Deficiency) by Rate Class

Rate Class	Rate of Return By Class	Revenue Excess or (Deficiency)
Residential	2.498%	($19,599,153)
Small General	4.199%	($1,717,605)
Irrigation	(4.061%)	($125,973)
Large General Primary	5.533%	($1,274,750)
Large General Secondary	10.448%	$6,454,832
TOD Large General Primary	6.867%	($4,106)
TOD Large General Secondary	11.329%	$156,616
Space Heating	5.307%	($336,128)
Small Municipal	0.903%	($117,868)
Municipal Lighting Primary	14.815%	$16,238
Municipal Lighting Secondary	9.628%	$179,242
Municipal Pumping Primary	2.874%	($281,162)
Municipal Pumping Secondary	7.930%	$26,248
Outdoor Lighting	7.600%	$3,184
Interruptible Demand Response	11.627%	$279,336
Special Contracts	-	($1,198,470)
SYSTEM TOTAL	5.347%	($17,539,519)

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Montana-Dakota taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in Section VII of this testimony.

Q. Please describe the COSS schedules attached to this testimony.

A. There are three schedules attached to this testimony that provide further details of the COSS that include the following information: They are:

- Statement K, Cost of Service by Component, consists of 17 pages and presents a summary of each rate class's projected 2023 Test Year rate base, the revenue requirements necessary to achieve the requested rate of return, and the rates of return under current rates.
- Statement K, Schedule K-1, consists of 102 pages and presents the Rate Base, Revenue, and Expenses by Class at Current Rates. This schedule provides the detail by cost and revenue component resulting in the projected rate base and class rates of return at current rates.
- Statement K, Schedule K-2, Allocation Factor Report, consists of 27 pages and shows the development of the factors used to allocate costs to the rate classes.

Q. Please explain the COSS information contained in Statement K.

A. Statement K, 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 7.513 percent were to be earned for the demand – production and transmission, demand – distribution, energy, and customer cost components of each rate schedule. Statement K also shows the system total rate of return before increase as well as the individual rate schedule rates of return before increase.

Statement K, Schedule K-1, is a report of the projected 2023 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-2.

The COSS is based on a projected 2023 average test period for North Dakota electric operations sponsored by Company witness Ms. Vesey.

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) 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.[3]

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 electric power producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing 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 electric utility system is designed and constructed to meet the peak requirements of customers using the most economic 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

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[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

are set at levels higher than the value of service, consumers will not purchase the service.

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.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices 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 was 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. As noted above, there are tensions between cost and value of service principles. 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. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate 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 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 must be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $17,539,519 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 ratio for each class was equal to 1.00 (Unity), as shown in Statement L, Schedule L-1, 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.

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-fuel revenues (see *Scenario A, Equal Percentage Increase*, in Statement L, Schedule L-1). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS 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 limit the increase to customer classes above parity to receiving a revenue increase equal to 1/3 of the system average increase, or 4.634%, and cap the maximum increase to any class at 35%, with the balance of the increase going to the Residential class. Classes where an increase between 4.634% and 35% would bring them to parity were brought to parity. This option would mitigate the divergence from parity for those classes above parity, while making reasonable movement towards parity for the other classes[4] (see *Scenario B*, *Minimum Class Increase of 1/3 of System Average, Maximum of 35% Increase, Remainder to Residential*, in Statement L, Schedule L-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 10, 13, and 16), Small General Service (Rate Schedule 20 and 26), Irrigation Service (Rate Schedule 25), Large General Service (Rate Schedule 30), TOD Large General Service (Rate Schedule 31), Space Heating (Rate Schedule 32), Small Municipal Service (Rate Schedule 40), Municipal Lighting Service (Rate Schedule 41), Municipal Pumping Service (Rate Schedule 48), Outdoor Lighting Service (Rate Schedule 52), Interruptible Demand Response Service class (Rate Schedule 38) and Special Contact customers, as shown in Statement L.

In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve the class's revenue to cost ratio from 0.73 to 0.88.

[4] Special contact customers were limited to the same percentage increase as Rate 30, Large General Service, Primary.

The Small General Service (0.82), Large General Service Primary (0.88), and Space Heating (0.87) customers classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.513%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity.

The maximum revenue increase of 35% is proposed for the Irrigation Service (0.34), Small Municipal Service (0.64), and Municipal Pumping Service Primary (0.73) customer classes. The Special Contract customers were limited to the same revenue increase as the Large General Service Primary class, or 13.239%.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue <u>decreases</u> in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in Statement L, Schedule L-1, under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes, or alternatively, exempting these classes from revenue increases. Instead, the proposed respective revenue adjustments of 1/3 of the system average increase to eligible customers, will mean these classes will be slightly higher than their current parity ratio levels relative to unity. The revenue increase for TOD Large General Service Primary was further adjusted to reflect the minimum adjustment of 1/3 of the system average increase because raising the class to parity was lower than this minimum threshold.

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 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 class rate subsidies, is desirable.

Statement L, Allocation of Revenues, 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 $17,539,519 to the respective rate schedules is presented in Statement L, page 2. The target revenue increase as a percentage of total class revenues, excluding fuel costs, range from 15.9% to Residential, 17.4% to Small General, 4.8% to Large General, 6.9% to Municipal Lighting, 10.8% to Municipal Pumping, and 3.5% to Outdoor Lighting.

VIII. 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. Montana-Dakota has proposed 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, as shown on Schedule L:

- Residential Service (Rates 10, 13 & 16);
- Small General Service (Rates 20 & 26);
- Irrigation Service (Rate 25);
- Large General Service (Rates 32 & 38); and
- Municipal Service (Rate 40).

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement L the Basic Service Charge under Residential Rate 10 is proposed at $0.67 per day which reflects an average monthly charge of $20.38, an increase of approximately $6.39 per month from the currently effective charge. This proposed charge reflects the $29.28 customer component identified in the embedded class cost of service as shown on Statement K, page 1. The Basic Service Charge is collected on a daily basis in order to avoid prorating the monthly charge when customers are in service less than 30 days, on average, or when a billing period extends beyond a 30 day average. A typical residential customer, using 800 Kwh on a monthly basis will see an increase in their electric service bill of $14.94 on a monthly basis as shown on Exhibit No. (RJA-2), page 1.

The following process was used to determine the rate components for each of the other rate schedules:

1. The first step was to establish the Basic Service Charge by considering the customer costs identified in the COSS and the Demand Charge

based on the demand costs identified in the COSS, for those rate schedules where demand metering is warranted.

2. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and Base Fuel and Purchased Power components for each rate schedule.
3. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the proforma sales under the applicable rate schedule.

The calculations just described are provided for each rate schedule on pages 7 – 26 of Statement L. A summary of the proposed charges for each rate schedule is provided on Statement L pages 4 and 5.

Q. Was there an exception to the process that you just described for any Rate Schedule?

A. Yes. Rate 32 allows for heat pump use, which operate in the summer in cooling mode. Therefore, Montana-Dakota determined that the summer demand charge for Rate 32 should be equivalent to the Rate 30 demand charge. The proposed Rate 32 summer demand charge was matched to the Rate 30 demand charge and the secondary energy charge was increased by the percentage increase allocated to the Rate Class.

Q. Please further discuss your proposal to increase the Basic Service Charge component of the previously identified rate schedules?

A. The Basic Service Charge component of each rate schedule has been set at or near the cost per customer component identified in the embedded class cost of service study. As shown on Schedule K-1, the customer component reflects those costs that vary by the number of customers served in each rate class. This includes the investment in meters and services that directly serve each individual customer, and a portion of the investment in poles, overhead and underground conductors, and line transformers. Through the COSS, these facilities have been determined to be associated with the minimum investment necessary to provide service to a customer regardless of the energy or peak load requirements of that customer.

The Basic Service Charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the Basic Service Charge in order to minimize intra-class subsidies and provide customers with the appropriate economic price signals. Increasing the Basic Service Charge to the amount identified as necessary to recover customer-related fixed costs does not provide a disincentive to use energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;
- Mitigating the impact abnormal weather has on the Company's ability to recover fixed cost;
- Residential customers' bills will be more stable as approximately 19.4 percent of the total bill will be fixed each month and not dependent on changes in weather; and
- Provides a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less energy than average.

IX. <u>CUSTOMER BILL IMPACTS</u>

Q. Has Montana-Dakota prepared a bill comparison for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Residential customer using 800 Kwh per year is shown on page 1 of Exhibit No.___(RJA-2), Rate 10 Residential Bill Comparison for electric service. The average monthly increase for this residential customer under the Company's proposed rate design is $14.94 or 16.6%.

Q. Has Montana-Dakota prepared overall bill impacts by Rate Class?

A. Yes. Total overall bill impact revenues and percentages, and base rate bill impact percentages by Rate Class, are presented on Exhibit No. ____(RJA-1).

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

42

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

Great Plains Natural Gas (2021)
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

Until Electric System and Northern Utilities, Inc. (2021)
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. Cases are currently pending before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021)
Retained to review and assist in the regulatory approval process of the Cost of Service Study for Centra Gas Manitoba's natural gas operations. Prepared a report assessing Centra's current COSS method in conformance with the regulatory requirements of the Manitoba Public Utilities Board.

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. The case is currently pending before the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021)
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 and North Dakota Public Service Commission. 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.

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)
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. Future project work involves working on the re-design of the

general service and industrial rate schedules, economic development rate strategies, demand response rates, and other 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 is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

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
- 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
- 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.
ELECTRIC UTILITY - NORTH DAKOTA

Overall Bill Impact
Case No. PU-22-_____

	Revenue at Current Rates				Generation Resource Recovery Rider (GRRR)							
Rate Class	Projected 2023 Revenue at Current Rates 1/	Rider Revenue 2/	Total Revenue	Rate Design Increase 3/	Proposed GRRR Revenue	GRRR at Current Rates	Net Increase in GRRR 4/	Proposed Increase	Total Proposed Revenue	Overall Bill Impact	Base Rate Bill Impact	GRRR Bill Impact
Residential Service	$69,769,528	$12,977,876	$82,747,404	$12,511,327	$3,221,567	$1,427,566	$1,794,001	$14,305,328	$97,052,732	17.3%	15.1%	2.2%
Small General Service	10,414,218	1,615,247	12,029,465	1,990,804	400,961	177,679	223,282	2,214,086	14,243,551	18.4%	16.5%	1.9%
General Service	88,497,679	17,403,425	105,901,104	6,011,117	4,014,827	1,763,008	2,251,819	8,262,936	114,164,040	7.8%	5.7%	2.1%
Municipal Lighting	980,235	183,996	1,164,231	78,471	17,434	11,153	6,281	84,752	1,248,983	7.3%	6.7%	0.5%
Municipal Pumping	2,878,349	613,256	3,491,605	379,396	168,837	67,663	101,174	480,570	3,972,175	13.8%	10.9%	2.9%
Outdoor Lighting Service	362,968	60,721	423,689	16,328	5,230	3,672	1,558	17,886	441,575	4.2%	3.9%	0.4%
Total North Dakota Electric	**$172,902,977**	**$32,854,521**	**$205,757,498**	**$20,987,443**	**$7,828,856**	**$3,450,741**	**$4,378,115**	**$25,365,558**	**$231,123,056**	**12.3%**	**10.2%**	**2.1%**

1/ Statement F, Schedule F-1, Page 1 includes Generation Resource Recovery Rider revenue.
2/ Transmission Cost Adjustment and Reneweable Resource Cost Adjustment revenue reflecting current rates.
3/ Includes the $3,450,741 currently being recovered through the Generation Resource Recovery Rider that will be collected through base rates.
4/ Reflects the net increase for the GRRR as $3,450,741 is already reflected in the current GRRR rates.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Estimated Residential Bill Increases
2023

		Current Rates					Proposed Rates				
	Kwh	Base Rate	Energy	Riders	FPP Charge	**Total Current Bill**	Base Rate	Energy	Riders	FPP Charge	**Total Proposed Bill**
January	1,000	$14.26	$49.28	$18.87	$22.41	$104.82	$20.77	$57.62	$21.22	$22.41	$122.02
February	1,000	12.88	49.28	18.87	22.41	103.44	18.76	57.62	21.22	22.41	120.01
March	1,000	14.26	49.28	18.87	22.41	104.82	20.77	57.62	21.22	22.41	122.02
April	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
May	600	14.26	34.07	11.32	13.45	73.10	20.77	39.07	12.73	13.45	86.02
June	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
July	800	14.26	45.42	15.10	17.93	92.71	20.77	52.10	16.98	17.93	107.78
August	1,000	14.26	56.78	18.87	22.41	112.32	20.77	65.12	21.22	22.41	129.52
September	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
October	600	14.26	34.07	11.32	13.45	73.10	20.77	39.07	12.73	13.45	86.02
November	600	13.80	34.07	11.32	13.45	72.64	20.10	39.07	12.73	13.45	85.35
December	900	14.26	46.60	16.98	20.17	98.01	20.77	54.11	19.10	20.17	114.15
	9,600	$167.90	$518.10	$181.15	$215.16	**$1,082.31**	$244.55	598.14	$203.70	215.16	**$1,261.55**
	800										
Change by Component							$76.65	$80.04	$22.55	$0.00	**$179.24**
											16.6%
										Per Month	$14.94

	Current	Proposed
Basic Service Charge/ Day	$0.46	$0.67
Energy		
1st 750 winter & summer	$0.05678	$0.06512
Over 750 winter	0.02678	0.03512
TCA	0.00801	0.00801
ECRR	0.00000	0.00000
GRRR	0.00187	0.00422
Renewable Rider	0.00899	0.00899
Fuel	0.02241	0.02241
Total Riders (excl Fuel)	0.01887	0.02122

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-22-___

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 projected billing determinants allocated to the Company's various rate schedules and priced at current rates, as included in Statement F, Schedule F-1 of this Application, the proposed rate schedules provided in Appendix B to the Application, and other proposed changes in the Company's tariff. I will also discuss the load research study completed for use in the embedded class cost of service study.

Additionally, I 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 Electric 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 Commission of Minnesota.

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>Projected Billing Determinants and Revenue Analysis</u>

Q. Please describe the derivation of the Company's projected billing determinants used in this rate case.

A. I will first discuss the derivation of the projected 2022 and 2023 customers included in this rate case. To start, Montana-Dakota determined the average number of customers for 2021 by rate schedule. The Company then applied the average growth rate to the 2021 customers, for select rate schedules, as included in the Company's financial forecast. For all other rate schedules, the Company is projecting no growth in customers and therefore set the projected 2022 and 2023 customers to the same level as that seen in 2021.

For the projected 2022 and 2023 energy use, Montana-Dakota's starting point was the overall projected North Dakota energy use as included in the Company's financial forecast and electric load forecast as outlined in the direct testimony of Mr. Darcy Neigum. As the customer classes included in the Company's electric load forecast do not align one for one with the Company's rate schedules, allocation factors were necessary to apportion the total projected North Dakota energy use to each of the respective rate schedules. However, prior to any allocation, Montana-Dakota first adjusted its 2021 per books energy use for any known customer changes expected to occur in 2022 or 2023. Two such changes were initially identified. The first known change was a customer request received in early 2022 to move a number of their accounts taking service in 2021 under Optional Time-of-Day General Electric Service Rate 31 Secondary to General Electric Service Rate 30 Secondary. The second known change was to move the billing determinants for a customer taking service under Interruptible Large Power Demand Response Rate 38 in 2021 that is now taking service under General Electric Service Rate 30 Primary.

Montana-Dakota then set the energy use the same as the 2021 energy use for any rate schedule where no customer growth was projected. For any rate schedule that reflected customer growth, Montana-Dakota allocated the remaining net projected energy use for 2022 and 2023 based on the applicable rate schedules' 2021 share of North Dakota's forecasted energy use.

Lastly, the Company was recently advised of a customer's intent to install distributed generation technology at a facility located in North Dakota. As the anticipated load reduction was only recently received and therefore not reflected in the Company's electric load forecast used in this rate case, Montana-Dakota subtracted the expected energy savings resulting from this customer installation from the total North Dakota projected energy use included in that customer's rate class and the electric load forecast to derive the total North Dakota energy use projected for the years 2022 and 2023.

The Company next projected customer demand by rate schedule, if applicable, by maintaining the load factor by month in 2021 for each rate schedule when factoring in that rate schedule's projected energy use.

Q. Please explain the calculation of the projected revenue at current rates included in Statements F, Schedule F-1.

A. The Company applied the Basic Service Charges, Energy Charges, and Demand Charges applicable under each rate schedule, and as authorized in Case No. PU-16-666 and later updated to reflect the impact of the Tax Cuts and Jobs Act of 2017 in Case No. PU-18-89, to the projected number of customers, energy use, and demand to derive the revenues shown on Statement F, Schedule F-1, pages 1 and 2. In addition, the Company priced the projected energy use or demand, dependent on the rate schedule, at the current Generation Resource Recovery Rider (Generation Rider) rates effective February 1, 2022, excluding the surcharge. As explained further in the direct testimony of Ms. Tara Vesey, Montana-Dakota is moving costs currently being recovered through the Generation Rider into base rates and vice versa. Therefore, in order to correctly reflect the recovery of all costs to be recovered through the Company's base rates, Montana-Dakota is including the current Generation Rider in its revenues. The surcharge was excluded from the Generation Rider rates as it reflects a prior period over/under recovery of costs and therefore should be excluded from the Company's revenues. The Fuel and Purchased Power rates used in revenues reflects the projected Fuel and Purchased Power rates developed by Ms. Tara Vesey. The Company is proposing no changes to the costs being recovered through either the Transmission Cost Adjustment or the Renewable Resource Cost Adjustment and therefore excluded those riders from the projected revenue at current rates.

<u>Proposed Tariff Changes</u>

Q. The Company is proposing a number of changes to Municipal Lighting Service Rate 41. Could you please briefly outline those changes?

A. Montana-Dakota is proposing a number of changes to Municipal Lighting Rate 41. First, the Company is proposing to expand the availability of the rate schedule to include the lighting of all public streets, alleys, and other road right of ways, and to no longer limit the availability solely to those lighting facilities owned by a municipality. This expansion of availability necessitates a change to the title of the rate schedule to Public Lighting Service Rate 41.

The Company is also proposing to remove the discount available under today's rate schedule. In 2018 and 2019, the Company undertook an LED street lighting replacement project in North Dakota whereby the Company replaced older Company-owned street lighting fixtures with LED street lighting fixtures. This resulted in energy and maintenance savings and higher lumen output. This project was also prompted in part by the trend toward less availability of older lighting fixtures. At the time of this replacement project, Rate 41 customers were advised that the Company would be eliminating the ten percent discount provision when the Company filed its next rate case.

Montana-Dakota is also proposing to include on the rate schedule the monthly Facilities Charges applicable to lighting facilities owned, installed, and maintained by the Company. While these "rental type" charges are not new to the Company or the customer being billed the charges today, the Company has not previously included these charges on the Rate 41 schedule. The street lighting project afforded the Company the opportunity to standardize across the Company's North Dakota service territory the lighting facilities the Company will now install and/or maintain for the customer and the associated monthly rate applicable for such facilities. The inclusion of the Facilities Charges on the rate schedule also offers both the Company and customers a reference point as to the type of facilities and "rental charge" associated with such facilities. These charges are not applicable to lighting facilities owned by the customer and/or municipality.

And lastly, the Company is proposing to clarify the determination of the monthly energy usage when the lighting service is un-metered. Consistent with all other customers, un-metered Rate 41 customers are billed monthly; however, the determination of that monthly energy usage is computed using a daily consumption level times the number of days in a customer's billing period.

Q. Would you briefly describe any additional changes the Company is proposing to the Company's electric tariff?

A. The Company is proposing the following changes to its electric tariff as clearly identified in the legislative copy of the tariff provided in Appendix B of the Application:

- The Company is proposing an entirely new volume of its electric rate book, designated herein as NDPSC Volume 5, to supersede the current volume 4, in order to reflect the removal of "A Division of MDU Resources Group, Inc." in the tariff header of all rate schedules.
- The rates described by Mr. Ron Amen have been incorporated into the proposed rate schedules.
- Consistent with all other electric rates schedules, the Company is proposing the Basic Service Charge under Interruptible Large Power Demand Response Rate 38 be stated on the tariff rather than specified in each electric service agreement with the Company. Other changes proposed to Rate 38 include adding clarifying language to the rate's General Terms and Conditions provision regarding: the cost responsibility of equipment and upgrades that may be necessary for monitoring interruptions as will now be defined in paragraph 4, the definition of the annual period under paragraph 5

to be the same as the MISO planning year, any testing requirements required by MISO to ensure interruption capability of participating resources as now defined in paragraph 7 and the ability to respond to future MISO requirements as those requirements related to interruptions under Rate 38 as will now be provided for under proposed paragraph 8.

- Proposing changes to Outdoor Lighting Service Rate 52 to reflect current practices.
- Introduce a monthly Manual Meter Reading Charge assessed customers who request to have their electric meter read manually each month in lieu of the Company installing an AMR-equipped meter to obtain meter reads.
- Proposing clarifying language be added to select sub-sections of Section 600 – Metering under Electric Service Rules and Regulations Rate 110 regarding the installation of customer equipment ahead of the Company's meter.
- 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. Is the Company proposing any changes to the Company's Extension Policy Rate 112?

A. Yes. The Company is proposing to update the cost to revenue ratio identified in Rate 112 to reflect the costs and projected return included in this rate case. The cost to revenue ratio is used to determine if cost participation is warranted for an extension to proceed. Currently if the estimated project construction cost is greater than two times the estimated annual revenue, the extension will be made only with a contribution. Reflecting today's costs and projected return, Montana-Dakota is proposing a cost to revenue ratio of 3.8 to 1.

The other change the Company is proposing to Rate 112 is to exclude the cost of fuel and purchased power from the revenue used to determine cost participation. As fuel and purchased power is a pass-through cost, the use of margin to determine cost participation is a better representation of the dollars available to recover the project's investment.

Load Research Study

Q. Did the Company conduct a load research study in preparation for this rate case?

A. Yes. In 2020, Montana-Dakota conducted a load research study of its North Dakota electric customers reflecting 2019 data. The study was conducted in compliance with the Settlement Agreement approved in the Company's 2016 electric rate case (Case No. PU-16-666) where

Montana-Dakota agreed to utilize a stratified random sampling technique for selecting samples and the use of a ratio estimation technique to expand the same data into class demand estimates for future class cost of service study purposes.

Q. Please briefly describe the method by which the load research sample was selected for the Company's various rate schedules?

A. Montana-Dakota first reviewed its various rate schedules in order to determine which rates would require a random sampling and which rates would not. A random sampling of customers is typically required when a large number of customers take service under a particular rate schedule and therefore the data becomes too voluminous if all customer data were to be used. Montana-Dakota concluded that random samples would be necessary for the following rate schedules: (1) Residential Electric Service Rate 10, (2) Small General Electric Service Rate 20, and (3) General Electric Service Rate 30 Secondary. For all remaining rate schedules, the Company requested all hourly load data available be provided.

For the three rate schedules where a random sampling would be required, the Company reviewed each rate schedule's 2019 billing information to identify those accounts with twelve months of billing data. That data subset was then further separated into quartiles, using the Microsoft Excel quartile function whereby the quartiles provided four consumption levels in which to equally separate that rate schedule's customers into stratums. From there, the Company used an online random sample calculator to determine the number of accounts to sample from each stratum in order to achieve a design accuracy of +/- 4% at a 90% confidence level.

For stratum, the Company extracted the hourly load data from its fixed network for the number of accounts necessary to achieve the 90% confidence level. Accounts were again randomly selected within each stratum.

Q. As hourly load data was not available for all customers within any particular rate schedule, were adjustments to the load research results necessary in order to represent the entire rate schedule?

A. Yes, adjustments were necessary to each rate schedule's load research results in order to bring them in alignment with the actual billed energy for 2019 while maintaining the relationships resulting from the study's data.

Q. Were there any rate schedules the Company did not have load data available to perform a load research study?

A. Yes, hourly load data was not available for the following rate schedules: Residential Electric Thermal Energy Storage Service Rate 13 (4 customers), Optional Time-of-Day Residential Electric Service Rate 16 (4 customers), Optional Time-of-Day General Electric Service Rate 31 (68 customers), and General Electric Space Heating Service Rate 32 (587 customers). As a proxy, the Company estimated the rate schedules' peak data based on the otherwise applicable rate schedules' peak data, scaled to the rate schedule without hourly load data available.

<u>Interim Increase</u>

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue increase of $11,422,209 is proposed to be billed as a separate line item on the bill based on 9.317 percent of the amounts billed under the Basic Service Charge, Energy Charge and Demand Charges applicable under the Company's rate schedules.

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 Electric Rates. The proposed tariff sheets reflect the proposed interim increase of 9.317 percent to be applied to the amount billed under the Basic Service Charge, Energy Charge and Demand Charges. The interim rate will not be applicable to the amount billed under the Fuel and Purchased Power or any of the Company's riders (Renewable Resource Cost Adjustment, Generation Resource Recovery Rider, Environmental Cost Recovery Rider and Transmission Cost Adjustment). The interim increase represents an average increase of 5.9 percent over total projected 2023 revenues at current rates. Page 2 of Exhibit No. ___(SB-1) shows a typical residential bill for a Montana-Dakota customer reflecting the proposed interim increase, showing an average monthly increase of $5.33 from current rates, including Fuel and Purchased Power and all riders.

Q. Does this conclude your testimony?

A. Yes.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Residential Electric Service Rate 10
Bill Comparison Worksheet - Interim Rates

		Current Rates						
	Kwh	Basic Service Charge	Energy	Riders	F&PP Charge	Total Current Bill	Interim Increase	% Increase
January	1,000	$14.26	$49.28	$18.85	$22.41	$104.80	$5.92	5.6%
February	1,000	12.88	49.28	18.85	22.41	103.42	5.79	5.6%
March	1,000	14.26	49.28	18.85	22.41	104.80	5.92	5.6%
April	700	13.80	39.75	13.20	15.69	82.44	4.99	6.1%
May	600	14.26	34.07	11.31	13.45	73.09	4.50	6.2%
June	700	13.80	39.75	13.20	15.69	82.44	4.99	6.1%
July	800	14.26	45.42	15.08	17.93	92.69	5.56	6.0%
August	1,000	14.26	56.78	18.85	22.41	112.30	6.62	5.9%
September	700	13.80	39.75	13.20	15.69	82.44	4.99	6.1%
October	600	14.26	34.07	11.31	13.45	73.09	4.50	6.2%
November	600	13.80	34.07	11.31	13.45	72.63	4.46	6.1%
December	900	14.26	46.60	16.97	20.17	98.00	5.67	5.8%
	9,600	$167.90	$518.10	$180.98	$215.16	$1,082.14	$63.91	5.9%
Average	800						$5.33	

	Current
Basic Service Charge/ Day	$0.46
Energy	
1st 750 winter & summer	$0.05678
Over 750 winter	0.02678
TCA	0.00801
ECRR	0.00000
GRRR	0.00185
Renewable Rider	0.00899
Fuel - Proposed 2023 F&PP	0.02241
Interim Increase	9.317%