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

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

November 4, 2022

Mr. Will Rosquist
Regulatory Division Administrator
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601

RE: Application and Notice of Change in General Electric Rates
Docket No. 2022.11.___

Dear Mr. Rosquist:

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

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

Montana-Dakota is proposing an increase in electric rates which is driven primarily by the investments made since the last rate case, including the Heskett IV gas turbine, increases in O&M expenses, and increases in property taxes. The Company's net adjusted rate base has grown approximately $35.9 million or 17 percent since 2018.

The Company proposes a total increase of $10,499,415 based on an average test year for the twelve months ended June 30, 2022 adjusted for known and measurable changes. The proposed increase will affect approximately 25,600 electric customers in Montana. The proposed change in rates will affect customer classes by the following percentages:

Rate Class	Overall Class Impact
Residential Service	19.2%
Small General Service	15.1%
Large General Service	12.9%
Municipal Pumping	15.4%
Lighting	10.3%
Total	15.2%

Montana-Dakota also requests interim rate relief as set forth in its Application for Interim Increase in Electric Rates in the amount of $1,716,219, to be effective within 30 days. The interim rate increase was calculated in accordance with ARM §38.5.506.

Pursuant to ARM §38.5.503, the attached Notice has been served (as a part of this filing) to this Commission and the Montana Consumer Counsel and also provided to all parties on the Certificate of Service, which includes interested parties that participated in the last general rate case filed (Docket No. 2018.09.060).

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

- Notice and Certificate of Service
- The Application including:
  - Appendix A - Current Rate Schedules
  - Appendix B - Proposed Final Rate Schedules including a redlined version of tariffs denoting proposed changes
- The Application for Interim Increase in Electric Rates including:
  - Proposed Interim Rate Schedules
  - Statements and Workpapers underlying the interim request
- Prefiled Direct Testimony and Exhibits in support of the Application
- Supporting Statements and Workpapers required by the Commission's filing requirements, ARM §38.5.103 through §38.5.180

Please refer all inquiries regarding this filing to:

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

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

Mr. Michael Green
Crowley Fleck PLLP
900 N. Last Chance Gulch, Suite 200
Helena, Montana 59601
mgreen@crowleyfleck.com

The original and ten (10) copies of this Letter of Transmittal, Application and Notice, Appendices, Testimony and Exhibits, Statements, and Application for Interim Increase in Electric Rates, are hereby filed with the Montana Public Service Commission.

Four (4) copies of same have this day been mailed to the Montana Consumer Counsel, P.O. Box 201703, Helena, Montana 59620-1703. All of the materials included in this Application are available upon request.

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

IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Establish Increased Rates for Electric Service	)))	DOCKET NO. 2022.11.__

NOTICE

An Application to increase electric rates was filed with the Montana Public Service Commission on November 4, 2022 by Montana-Dakota Utilities Co. Such Application proposes a revenue increase of $10,499,415 representing an overall percentage increase of 15.2 percent.

Montana-Dakota has also requested that an interim increase of $1,716,219, to be effective within 30 days.

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

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

Dated this 4th day of November 2022.

Travis Jacobson

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

CERTIFICATE OF SERVICE

I certify that on the 4th day of November 2022, a true and accurate copy of Montana-Dakota Utilities Co.'s Application and Notice of Change in General Electric Rates in Docket No. 2022.11.___ was served by mail and email to the following:

Will Rosquist
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601
wrosquist@mt.gov

Mike Green
Crowley Fleck
900 N. Last Chance Gulch
Suite 200
Helena, MT 59601
mgreen@crowleyfleck.com

Jason Brown
Montana Consumer Counsel
111 N. Last Chance Gulch, Suite 1B
P.O. Box 201703
Helena, MT 59601-1703
jbrown4@mt.gov

Electronic Service Only:
ssnow@mt.gov
sking@crowleyfleck.com

Denbury Onshore LLC
tnelson@hollandhart.com
nsstoffel@hollandhart.com

/s/ Terese M. Birnbaum
Terese M. Birnbaum
Regulatory Analyst
Montana-Dakota Utilities Co.

Michael Green
Wiley Barker
Crowley Fleck PLLP
900 N. Last Chance Gulch, Suite 200
Helena, MT 59601
Phone: (406) 449-4165
Fax: (406) 449-5149
mgreen@crowleyfleck.com
wbarker@crowleyfleck.com

Attorneys for Montana-Dakota

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

In the Matter of the Application of	)	
MONTANA-DAKOTA UTILITIES CO. for	)	Docket No. 2022.11.__
Authority to Establish Increased Rates	)	
for Electric Service	)	

* * * * * *

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 Montana as a foreign corporation. Montana-Dakota is doing business in the State of Montana as a public utility.

II.

The Company's Certificate of Incorporation and Amendments thereto have previously been filed with the Montana 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.

Volume No. 4	Description
3rd Revised Sheet No. 1	Table of Contents
5th Revised Sheet No. 1.1	"
Original Sheet No. 2	Communities Served
11th Revised Sheet No. 3	Residential Electric Service Rate 10
5th Revised Sheet No. 3.1	"
6th Revised Sheet No. 4	Reserved for Future Use
3rd Revised Sheet No. 4.1	"
11th Revised Sheet No. 7	Optional Time-of-Day Residential Electric Service Rate 16
5th Revised Sheet No. 7.1	"
11th Revised Sheet Nos. 10 - 10.1	Small General Electric Service Rate 20
4th Revised Sheet No. 10.2	"
11th Revised Sheet No. 15	Irrigation Power Service Rate 25
4th Revised Sheet No. 15.1	"
11th Revised Sheet Nos. 16 - 16.1	Optional Time-of-Day Small General Electric Service Rate 26
4th Revised Sheet No. 16.2	"
11th Revised Sheet No. 18	Large General Electric Service Rate 30
5th Revised Sheet Nos. 18.1 - 18.2	"
11th Revised Sheet No. 19	Optional Time-of-Day Large General Electric Service Rate 31
8th Revised Sheet No. 19.1	"
4th Revised Sheet No. 19.2	"
6th Revised Sheet No. 20	General Electric Space Heating Service Rate 32
3rd Revised Sheet No. 20.1	"
2nd Revised Sheet No. 20.2	"
11th Revised Sheet No. 23	Contract Service Rate 35
4th Revised Sheet Nos. 23.1 - 23.2	"
3rd Revised Sheet No. 23.3	"
20th Revised Sheet No. 23.4	"
11th Revised Sheet No. 25	Interruptible Large Power Demand Response Rate 38
3rd Revised Sheet Nos. 25.1 - 25.2	"

11th Revised Sheet No. 28	Public Lighting Service Rate 41
5th Revised Sheet No. 28.1	"
11th Revised Sheet No. 34	Municipal Pumping Service Rate 48
4th Revised Sheet No. 34.1	"
11th Revised Sheet No. 38	Outdoor Lighting Service Rate 52
3rd Revised Sheet No. 38.1	"
8th Revised Sheet No. 39	Electric Line Moving Cost Schedule Rate 53
6th Revised Sheet No. 39.1	"
Original Sheet No. 41	Electric Universal System Benefits Charge Rate 55
Original Sheet Nos. 42 - 42.1	Electric Tax Tracking Adjustment Rate 56
7th Revised Sheet No. 42.2	"
4th Revised Sheet No. 43	Fuel and Purchased Power Cost Tracking Adjustment Rate 58
3rd Revised Sheet Nos. 43.1 - 43.3	"
175th Revised Sheet No. 43.4	"
1st Revised Sheet Nos. 44 - 44.2	Net Metering Service Rate 92
11th Revised Sheet No. 45	Power Purchase Time Differentiated Rate 93
9th Revised Sheet No. 45.1	"
5th Revised Sheet No. 45.2	"
2nd Revised Sheet No. 45.3	"
Original Sheet Nos. 46 - 46.1	Net Billing Option Rate 94
Original Sheet Nos. 47 - 47.1	Interconnection Cost Amortization Option Rate 95
Original Sheet Nos. 48 – 48.66	Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96
2nd Revised Sheet Nos. 52	General Provisions Rate 100
Original Sheet No. 52.1	"
1st Revised Sheet No. 52.2	"
2nd Revised Sheet Nos. 52.3 - 52.4	"
3rd Revised Sheet No. 52.5	"
2nd Revised Sheet Nos. 52.6 - 52.9	"
1st Revised Sheet No. 53	Reserved for Future Use
1st Revised Sheet No. 54	Reserved for Future Use
1st Revised Sheet No. 60	Reserved for Future Use
1st Revised Sheet Nos. 61 - 61.21	Electric Service Rules and Regulations Rate 110
2nd Revised Sheet No. 61.22	"
1st Revised Sheet Nos. 61.23 - 61.33	"
Original Sheet No. 61.34	"
1st Revised Sheet Nos. 63 - 63.2	Electric Extension Policy Rate 112
Original Sheet No. 63.3	"
1st Revised Sheet No. 65	Reserved for Future Use
1st Revised Sheet No. 68	Reserved for Future Use
1st Revised Sheet No. 71	Reserved for Future Use
1st Revised Sheet No. 74	Reserved for Future Use
Original Sheet Nos. 75 - 75.2	Selective Testing Plan for Watthour Meters Rate 131

V.

Montana-Dakota hereby respectfully 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 Docket:

Volume No. 5	Description
Original Sheet Nos. 1 - 1.1	Table of Contents
Original Sheet No. 2	Communities Served
Original Sheet Nos. 3 - 3.1	Residential Electric Service Rate 10
Original Sheet Nos. 7 - 7.1	Optional Time-of-Day Residential Electric Service Rate 16
Original Sheet Nos. 10 - 10.2	Small General Electric Service Rate 20
Original Sheet Nos. 15 - 15.1	Irrigation Power Service Rate 25
Original Sheet Nos. 16 - 16.2	Optional Time-of-Day Small General Electric Service Rate 26
Original Sheet Nos. 18 - 18.2	Large General Electric Service Rate 30
Original Sheet Nos. 19 - 19.2	Optional Time-of-Day Large General Electric Service Rate 31
Original Sheet Nos. 20 - 20.2	General Electric Space Heating Service Rate 32
Original Sheet Nos. 23 - 23.4	Contract Service Rate 35
Original Sheet Nos. 25 - 25.3	Interruptible Large Power Demand Response Rate 38
Original Sheet Nos. 28 - 28.1	Public Lighting Service Rate 41
Original Sheet Nos. 34 - 34.1	Municipal Pumping Service Rate 48
Original Sheet Nos. 38 - 38.1	Outdoor Lighting Service Rate 52
Original Sheet Nos. 39 - 39.1	Electric Line Moving Cost Schedule Rate 53
Original Sheet No. 41	Electric Universal System Benefits Charge Rate 55
Original Sheet Nos. 42 - 42.2	Electric Tax Tracking Adjustment Rate 56
Original Sheet Nos. 43 - 43.4	Fuel and Purchased Power Cost Tracking Adjustment Rate 58
Original Sheet Nos. 44 - 44.2	Net Metering Service Rate 92
Original Sheet Nos. 45 - 45.3	Power Purchase Time Differentiated Rate 93
Original Sheet Nos. 46 - 46.1	Net Billing Option Rate 94
Original Sheet Nos. 47 - 47.1	Interconnection Cost Amortization Option Rate 95
Original Sheet Nos. 48 – 48.66	Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96
Original Sheet Nos. 52 - 52.9	General Provisions Rate 100
Original Sheet Nos. 61 - 61.34	Electric Service Rules and Regulations Rate 110
Original Sheet Nos. 63 - 63.3	Electric Extension Policy Rate 112
Original Sheet Nos. 75 - 75.2	Selective Testing Plan for Watthour Meters Rate 131

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 Montana electric customers.

VII.

The new rates contained herein will provide additional annual revenues in the annual amount of $10,499,415 based on a twelve months ended June 30, 2023 future test year, for electric service rendered to customers in the State of Montana. This request amounts to a 15.2 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 $1,716,219 to be effective 30 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 Title 69 of the Montana Code Annotated and the rules and regulations promulgated by the Public Service Commission of the State of Montana.

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

1. Grant interim rate relief to Applicant in the amount of $1,716,219 in accordance with Applicant's Application for Interim Increase in Electric Rates, submitted herewith;
2. Approve and adopt the proposed rate changes as set forth in Appendix B of this Application that will produce an annual increase in revenues of $10,499,415 to be effective upon final disposition of this Docket; and

3. Grant such other and additional relief as the Commission shall deem just and proper.

Respectfully submitted this 4th day of November 2022.

MONTANA-DAKOTA UTILITIES CO.

By ______________________________

Michael W. Green
Crowley Fleck PLLP
Attorney for the Applicant
900 N. Last Chance Gulch, Suite 200
Helena, Montana 59601

Montana-Dakota Utilities Co.
Montana Electric Tariffs - Current

Appendix A

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

State of Montana
Electric Rate Schedule

TABLE OF CONTENTS

Designation	Title	Sheet No.
	Table of Contents	1-1.1
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10	Residential Electric Service	3-3.1
	Reserved	4-6
16	Optional Time-of-Day Residential Electric Service	7-7.1
	Reserved	8-9
20	Small General Electric Service	10-10.2
	Reserved	11-14
25	Irrigation Power Service	15-15.1
26	Optional Time-of-Day Small General Electric Service	16-16.2
	Reserved	17
30	Large General Electric Service	18-18.2
31	Optional Time-of-Day Large General Electric Service	19-19.2
32	General Electric Space Heating Service	20-20.2
	Reserved	21-22
35	Contract Service	23-23.4
	Reserved	24
38	Interruptible Large Power Demand Response	25-25.3
	Reserved	26-27
41	Public Lighting Service	28-28.1
	Reserved	29-33
48	Municipal Pumping Service	34-34.1
	Reserved	35-37
52	Outdoor Lighting Service	38-38.1
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55	Electric Universal System Benefits Charge	41

Issued: September 28, 2018

By: Tamie A. Aberle
Director – Regulatory Affairs

For Office Use Only – Do Not Print Below This Line

Docket No. D2018.9.60

Effective with service rendered on and after September 1, 2019

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56	Electric Tax Tracking Adjustment	42-42.2
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96	Small Generator Facility Distribution Interconnection Rules and Procedures	48-48.66
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112	Electric Extension Policy	63-63.2
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131	Selective Testing Plan for Watthour Meters	75-75.2
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COMMUNITIES SERVED

*Designates District Office

Badlands Region

Antelope	*Glendive	Redstone
Bainville	Homestead	Reserve
Baker	Ismay	Rosebud
Brockton	Kinsey	Savage
Culbertson	Medicine Lake	Scobey
Fairview	*Miles City	Sidney
Fallon	Outlook	Terry
Flaxville	Plentywood	Whitetail
Forsyth	Plevna	Wibaux
Froid	Poplar	*Wolf Point

RESIDENTIAL ELECTRIC SERVICE Rate 10

AVAILABILITY:

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

RATE:

Basic Service Charge:	$0.19 per day
Energy Charge:	
October – May	6.520¢ per Kwh
June – September	8.517¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. Low-Income Discount: Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered

based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP.

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

2. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Reserved for Future Use

Reserved for Future Use

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 arranged so that all service can be measured through one meter.

RATE:

Basic Service Charge: $0.36 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	6.384¢ per Kwh
June – September	9.639¢ per Kwh

Off-Peak Energy: 5.905¢ per Kwh for all energy not covered by the On-Peak rating period.

Base Fuel and Purchased Power: 2.542¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. 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 of returning to the regular Residential Electric Service rate.

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

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

3. The foregoing schedule is subject to Rates 100-131 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 of 50 Kilowatts or less 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:

Basic Service Charge:	$0.65 per day
Primary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$12.00 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$13.00 per Kw
Energy Charge:	
October – May	3.764¢ per Kwh
June – September	5.644¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ per Kwh
Secondary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$12.75 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$14.00 per Kw

Energy Charge:	
October – May	3.864¢ per Kwh
June – September	5.744¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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.

SMALL GENERAL ELECTRIC SERVICE Rate 20

GENERAL TERMS AND CONDITIONS:

1. Customer 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. The 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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:
For irrigation power service.

RATE:

Basic Service Charge:	$0.75 per day
Demand Charge:	
October – May	$3.00 per Kw
June – September	$5.00 per Kw
Energy Charge:	2.624¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-131 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 of 50 Kilowatts or less 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:	$31.89 per month
Primary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$12.75 per Kw
June – September	$15.74 per Kw
On-Peak Energy:	
October – May	5.687¢ per Kwh
June – September	6.973¢ per Kwh
Off-Peak Energy:	3.464¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ per Kwh
Secondary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$13.06 per Kw
June – September	$16.23 per Kw

On-Peak Energy:	
October – May	5.657¢ per Kwh
June – September	7.066¢ per Kwh
Off-Peak Energy:	3.505¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. Demands will be determined to the nearest one-tenth kilowatt.

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

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. 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. The 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. 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 of returning to the regular Small General Electric Service rate.

4. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

LARGE GENERAL ELECTRIC SERVICE Rate 30

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand 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:	$230.00 per month
Demand Charge:	
October – May	$11.10 per Kw
June – September	$12.45 per Kw
Energy Charge:	2.908¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ per Kwh

Secondary Service:

Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$11.30 per Kw
June – September	$12.65 per Kw
Energy Charge:	2.936¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 50 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. 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. The 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 100-131 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 LARGE GENERAL ELECTRIC SERVICE Rate 31

AVAILABILITY:

In all communities served for all types of demand metered general electric service exceeding 50 Kilowatts of billing demand 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:	$230.00 per month
On-Peak Demand Charge:	
October – May	$ 8.50 per Kw
June – September	$15.80 per Kw
On-Peak Energy:	
October – May	4.768¢ per Kwh
June – September	5.768¢ per Kwh
Off-Peak Energy:	2.768¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ per Kwh
Secondary Service:	
Basic Service Charge:	$100.00 per month
On-Peak Demand Charge:	
October – May	$ 9.50 per Kw
June – September	$16.50 per Kw

On-Peak Energy:	
October – May	4.768¢ per Kwh
June – September	5.768¢ per Kwh
Off-Peak Energy:	2.768¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. 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. 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 agrees to contract for service under the Optional Time-of-Day Large 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 Large General Electric Service rate or of returning to the regular Large General Electric Service rate.

3. The 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.

4. The foregoing schedule is subject to Rates 100-131 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 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:	$30.00 per month
Primary Service:	
Demand Charge:	
October – May	$2.75 per Kw
June – September	$12.45 per Kw
Energy Charge:	2.433¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$3.25 per Kw
June – September	$12.65 per Kw
Energy Charge:	2.433¢ per Kwh
Base Fuel and Purchased Power:	2.542¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

CONTRACT SERVICE Rate 35

AVAILABILITY:

For the Denbury Onshore LLC accounts designated in the Electric Service Agreement dated June 28, 2017.

RATE:

Basic Service Charge:	$250.00 per month
Demand Charge:	
October – May	$ 8.50 per Kw
June – September	$10.00 per Kw
Energy Charge:	2.174¢ per Kwh
Base Fuel and Purchased Power:	2.456¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

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 50 Kw. Demands will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

Montana-Dakota reserves the right to require Denbury Onshore LLC 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 Denbury Onshore LLC 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:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by Montana-Dakota under the laws of the state.

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT:

The following sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment for Contact Service Rate 35. It specifies the procedure to be utilized to adjust the rates for electricity sold in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account as allocated to Contract Service Rate 35.

1. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   Unless otherwise ordered by the Commission, the effective date of the Fuel and Power Cost Tracking Adjustment and amortization of the Unreflected Fuel Cost Account shall be service rendered on and after January 1 each year.

2. FUEL AND POWER COST TRACKING ADJUSTMENT:
   a. The Fuel and Power Cost Tracking Adjustment shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base

fuel cost shall be 2.456¢ per Kwh as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for Rate 35, and shall be the sum of the following estimated costs for the annual period the adjustment shall be in effect, as allocated to Montana and to Contract Service Rate 35, taking into account applicable line losses:
   1. The cost of fossil and other fuels and sand and reagents as recorded in Account Nos. 501, 502 and 547.
   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555.
   3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the year is the sum of 2(b) above divided by projected Contract Service Rate 35 sales volumes for the period the adjustment will be in effect.

d. The Annual Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 2(b) multiplied by ninety (90) percent.

3. UNREFLECTED FUEL COST ADJUSTMENT:
   Contract Service Rate 35 shall be subject to an Unreflected Fuel Cost Adjustment to be effective on January 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

4. UNREFLECTED FUEL COST ACCOUNT:
   a. Items to be included in the Unreflected Fuel Cost Account are:
      1. Amounts under recovered or over recovered for fuel and purchased power each month as calculated in accordance with Subsection 4(b).
      2. Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

   b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 4(a)(1) and (2) shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power.
      2. Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.
      3. The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in an Unreflected Fuel Cost Account for Contract Service Rate 35.
      4. Carrying charges or credits at a rate equal to the overall rate of return established in the most recent general rate case.

   c. Reduction of Amounts in the Unreflected Fuel Cost Account:
      1. The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 4) under Contract Service Rate 35. The Account shall be increased in the event the adjustment is a negative amount. The amount amortized shall be applied pro rata between the Unrecovered Fuel Cost Account and the interest balance.

5. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES: The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

6. TIME AND MANNER OF FILING:
   a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 6 identifying the amount of the adjustment.

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

7. EFFECTIVE ADJUSTMENT:

Base Fuel	2.456¢
Fuel and Power Cost Adjustment	(0.495¢)
Total Adjustment per Kwh	1.961¢

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	$6.10 per Kw
June – September	$7.45 per Kw
Energy Charge:	2.908¢ per Kwh
Base Fuel and Purchased Power:	2.523¢ 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.

ADJUSTMENT CLAUSES:

Bills are subject to the following adjustments as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 Base Rate payments to the Company. The monthly Base Rate 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 used 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 100-131 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 public 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.

ENERGY RATE:

7.173¢ per Kwh computed according to the total rated capacity of the lamps in use.

Base Fuel and Purchased Power: 2.542¢ per Kwh

FACILITIES CHARGE per unit per month:

Applicable to lighting facilities owned, installed, and maintained by the Company.

LED, Overhead Conductor, Distribution Pole	$4.00
LED, Overhead Conductor, Street Light Pole	$7.60
LED, Underground Conductor, Distribution Pole	$5.10
LED, Underground Conductors, Street Light Pole	$8.70
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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 municipality for the cost of repair and replacement.

2. The energy rate charged to municipally-owned street lighting systems shall be the above tariffed rate less 0.500¢ per Kwh.

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 energy usage shall be computed on an 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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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:

Basic Service Charge: $30.00 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	$4.00 per Kw
June – September	$6.00 per Kw

Energy Charge: 3.211¢ per Kwh

Base Fuel and Purchased Power: 2.542¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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:

The foregoing schedule is subject to Rates 100-131 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, Christmas lights and metallic vapor yard light units in all communities served. Lighting equipment may be Company-owned or customer-owned.

RATE:

11.695¢ per Kwh computed according to the total rated capacity of the units in use.

Base Fuel and Purchased Power: 2.542¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 customers 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 customer. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

2. 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. Christmas lighting will be billed for the months in service.

   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.

3. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

ELECTRIC LINE MOVING COST SCHEDULE Rate 53

APPLICABILITY:

This rate schedule sets forth the charges to be applied to recover the costs associated with the expense of moving poles or raising or cutting wires or cables to accommodate the relocation of a structure, as required by Montana Code Annoted (MCA) Section 69-4-602 and 69-4-603.

CHARGES:

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a house, building, derrick, other structure, or prefabricated structure that is intended to be moved from the place of fabrication, storage facility, or dealer's lot, determined in accordance with the rates set forth below must be paid by the mover.

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a structure, determined in accordance with the rates set forth below must be shared equally by the mover and the owner of the wires, cables, or poles if the structure is owned by a person for occupancy or use by that person.

RATE:

Refer to Cost Schedule for current rate information

GENERAL TERMS AND CONDITIONS:

1. Prepayment – The mover shall make a prepayment of a portion of the estimated total cost in advance of the move as follows:
    a. If the structure is moved through or out of the Company's service territory, 100% of the mover's share.
    b. If the structure is delivered to a place within the Company's service territory, 50% of the mover's share.
    c. The Company may waive the prepayment requirement or accept a bond or other financial instrument in lieu of payment.

d. The mover shall pay the mover's share of all actual costs in excess of any prepayment within 30 days of the move.

e. If the prepayment made exceeds the mover's share of actual costs the Company shall refund the difference to the mover within 30 days of the move.

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

ELECTRIC UNIVERSAL SYSTEM BENEFITS CHARGE Rate 55

APPLICABILITY:

In all communities served for all retail electric service in order to recover the costs associated with Universal System Benefit Programs required by the Electric Utility Industry Restructuring and Customer Choice Act, Montana Code Ann. §§69-8-101.

RATE:

Large Customer Accounts(Defined Below):	.0900¢ per Kwh for all energy used.
All other accounts:	.1566¢ per Kwh for all energy used.

GENERAL TERMS AND CONDITIONS:

1. Large Customer Accounts are defined as any customer with monthly billing demands of 1,000 Kw or higher, determined by dividing the customer's previous calendar year's total billing demand by 12.

   a. Large Customer Accounts shall be charged an annual Universal System Benefits Charge(USBC) assessment equal to the lesser of $500,000 or the product of .09¢ per Kwh for all energy used.

   b. Large Customer Accounts shall receive a credit toward their annual USBC assessment for internal expenditures and activities that qualify as Universal System Benefit programs as determined by the Montana Department of Revenue.

   c. Large Customer Accounts with qualifying credits that exceed the customers annual USBC assessment shall be carried forward and credited to customer's future USBC assessments until the total amount of the qualifying credits have been credited to the customer's account.

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

ELECTRIC TAX TRACKING ADJUSTMENT Rate 56

1. Applicability:

This rate schedule sets forth the procedure to be used in calculating the Tax Tracking Adjustment in order to reflect: (a) changes in Montana-Dakota's Montana state and local taxes and fees, and (b) a true-up of taxes recovered to actual taxes paid. The tax adjustment shall be shown as a separate item on the bill.

2. Effective Date:

The effective date of the Tax Tracking Adjustment shall be service rendered on and after May 15, 2017 and shall be adjusted annually thereafter on January 1 each year.

3. Tax Tracking Adjustment:

a. The Tax Tracking Adjustment shall reflect changes in Montana-Dakota's Montana state and local taxes and fees as compared to the base levels approved in its most recent general rate case. The difference to be included in the Tax Tracking Adjustment shall be net of income taxes.

b. Base Tax – A base tax amount shall be established and updated in general rate cases for each rate schedule:

(1) The ratio of authorized Montana state and local taxes and fees, excluding tribal taxes, to the non-fuel revenues shall be determined.

(2) The ratio is applied to the total basic service charge, energy charge, and demand charge revenues for each rate schedule to derive the base tax amount for each rate schedule.

c. Rates excluding taxes

(1) The authorized non-fuel revenue excluding base taxes (defined as base margin) is established by applying one minus the ratio derived in 3.b.(1) to the authorized non-fuel revenues by rate schedule.

(2) The percentage of base taxes to base margin is derived to establish the baseline tax recovery amounts included within the basic service charge,

energy charge and demand charge by applying that percentage to each rate component of each rate schedule.

d. The Tax Tracking Adjustment shall have two components and be computed as follows:

(1) Rate Year Estimate- To recover changes in estimated tax expenses from the base tax level for the year in which the rates will apply (the "Rate Year"), actual tax expense for the prior year shall be used as a proxy for Rate Year taxes and compared to the tax expense projected to be recovered in the Rate Year. That difference (whether positive or negative), adjusted for income taxes, is the Rate Year estimate component. For Rate Year 2017 only, the Rate Year Estimate will be charged only during the period May 15, 2017 to December 31, 2017.

(2) Annual True-Up- To true-up each year's tax expense recovered to the actual tax expense for that year, the actual tax expense for the year prior to the Rate Year is compared to the tax expense recovered in the same year. That difference (whether positive or negative), adjusted for income taxes, is the Annual True-Up component. For Rate Year 2018 only, the true-up will be calculated using the difference between tax expense recovered and actual tax expense for the period May 15, 2017 to December 31, 2017. No Annual True-Up component applies to Rate Year 2017.

(3) The sum of amounts (positive or negative) in 3.d.(1) and 3.d.(2) above is divided by the base margin to derive the percent increase (decrease) in taxes.

(4) The base tax percentage determined in 3.c.(2) and the tax adjustment percentage determined in 3.d.(3) are added to calculate the total percent of taxes.

(5) The total percent of taxes is applied to the base margin, comprised of the basic service charge, energy charge, and demand charge billed to each customer, and shown separately on the customer bill.

4. Time and Manner of Filing:
A filing shall be made on or before November 30 of each year to modify the Tax Tracker Adjustment for the subsequent year. That filing shall be accompanied by the detailed computations which clearly show the derivation of the relevant amounts.

5. Tax Tracking Adjustment:

Base	8.5063%
Adjustment	1.6594%
Total tax	10.1657%

1. APPLICABILITY:
This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 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 tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:
Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs by month by source, with annual totals;

b. Generation and purchases (Mwh) by month by supply source, with annual totals;

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

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

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

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.523¢ per Kwh for primary service and 2.542¢ per Kwh for secondary service as established in the most recent general rate case.

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 Montana and to the primary and secondary customer classes:

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

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

3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 4(c) multiplied by ninety (90) percent.

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

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

(1) Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power as specified in Subsection 4.

(2) Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.

(3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in the Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

(1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES:
The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

8. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

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

9. FUEL AND POWER COST ADJUSTMENT:

	Primary	Secondary
Base Fuel	2.523¢	2.542¢
Fuel and Power Cost Adjustment	(0.215)	(0.288)
Total FPPA per Kwh	2.308¢	2.254¢

NET METERING SERVICE Rate 92

AVAILABILITY:

Available to any customer with a small generator facility whose capacity does not exceed 50 Kw that is located on the customer's premises and is intended primarily to offset part or all of the customer's own electrical requirements. The small generating facility, hereinafter referred to as eligible customer generator, must be interconnected and operated in parallel with the Company's existing distribution facilities.

APPLICABILITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator that exceeds the customer's own use or is sold to Montana-Dakota.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Demand Charge: The Demand Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill. The balance of the energy generated shall appear as a credit on the customer's account until the customer's consumption offsets the credit or the end of the designated 12-month billing period, which ever occurs first. At the end of the 12-month period any unused Kwh credit

accumulated during the previous 12-months will be granted to the Company with no compensation to the customer. The customer shall designate the start date of the 12-month billing period as January 1, April 1, July 1 or October 1.

GENERAL TERMS AND CONDITIONS:

1. INTERCONNECTION AGREEMENT:
   Prior to connecting a renewable energy system to operate in parallel with the utility, the eligible customer-generator must initiate and enter into an Interconnection Agreement with the Company in accordance with Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96.

2. INTERCONNECTION AND OPERATION:
   a. Upon completion of a signed interconnection agreement and the initiation of service, the customer shall operate its Small Generator Facility in parallel with Montana-Dakota's system and in accordance with the terms of the Interconnection Agreement, Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff and the Administrative Rules of Montana 38.5.84.
   b. There should only be one net metering system installed per each metered service located on the customer's premises. The net metering system must have an aggregate nameplate capacity per premise that does not exceed 50 Kw and be fueled by solar, wind, or hydropower.
   c. Neither customers, customer accounts or services, nor meters may be aggregated for purposes of net metering.

3. METERING:
   Montana-Dakota will provide a standard meter capable of registering the flow of electricity in two directions. Any additional costs necessary for the interconnection are the responsibility of the customer in accordance with

Rate 96 ¶ VIII.5 and as outlined in the Small Generator Facility Distribution Interconnection Agreement.

4. INTERRUPTION OF DELIVERIES:
The Company may require the customer to interrupt or reduce deliveries of available energy when Company determines (a) such interruption is necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any Company-owned equipment or part of the Company's system, or (b) that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with any electrical code or standard. Whenever possible, Company will give the customer notice of the possibility that interruption or reduction of deliveries may be required.

5. TEMPORARY DISCONNECTION OF FACILITY:
If at any time the Company determines that either (a) the customer's eligible generator, or its operation, may endanger Company personnel, or (b) the continued operation of the generator may endanger the integrity of the Company's electric system, the Company shall have the right to disconnect the generator from the Company's system. The Company will give the customer notice of such occurrence as soon as practical. The customer's eligible generator will remain disconnected until such time as the Company determines that all condition(s) are such that it is safe to reconnect.

   The Company is not obligated to pay for energy that would otherwise have been delivered to its system absent the occurrences described in this section.

6. The foregoing schedule is subject to Rates 101 through 131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:

To any qualifying cogeneration and small power production facility (QF), as defined under the Administrative Rules of the Montana Public Service Commission, for the purpose of generating electric energy in parallel with the Company's system, including ARM 38.5.1909 and any amendments or alternations to the rule. This schedule is applicable to a QF with a nameplate capacity of 3 MW or less who enters into a Power Purchase Agreement (Agreement) with the Company for a term not to exceed 15 years.

RATE:

Metering charge for single phase service	$6.50 per month
Metering charge for three phase service	$10.45 per month

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. Time Differentiated Energy Purchase Rate

	ON-PEAK	OFF-PEAK
2021	2.194¢ per Kwh	2.267¢ per Kwh
2022	2.072¢ per Kwh	2.139¢ per Kwh
2023	2.134¢ per Kwh	2.203¢ per Kwh
2024	2.198¢ per Kwh	2.269¢ per Kwh
2025	2.264¢ per Kwh	2.337¢ per Kwh
2026	2.332¢ per Kwh	2.407¢ per Kwh
2027	2.402¢ per Kwh	2.479¢ per Kwh
2028	2.474¢ per Kwh	2.553¢ per Kwh
2029	2.548¢ per Kwh	2.630¢ per Kwh
2030	2.624¢ per Kwh	2.709¢ per Kwh
2031	2.703¢ per Kwh	2.790¢ per Kwh
2032	2.784¢ per Kwh	2.874¢ per Kwh
2033	2.868¢ per Kwh	2.960¢ per Kwh
2034	2.954¢ per Kwh	3.049¢ per Kwh
2035	3.043¢ per Kwh	3.140¢ per Kwh
2036	3.134¢ per Kwh	3.234¢ per Kwh

Rating 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 Company's system operating characteristics.

2. Actual time differentiated system lambda determined for the month prior to the month in which energy is delivered by a QF.

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- Resource Adequacy of the MISO tariff.

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

Capacity payments will be paid in the subsequent billing period.

Monthly capacity payments 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 $10.004 per Kw applicable for the remainder of the term of the contract.

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 or large general service, etc.) that is currently on file with the Commission.

GENERAL TERMS AND CONDITIONS:

1. All purchases and sales of electric power between the Company and a QF of 3 MWs or less shall be accomplished according to the terms of a written contract and in accordance with the terms of this tariff.

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

3. The QF must apply for and enter into an Interconnection Agreement with the Company or the Transmission Service Provider prior to actual installation of equipment. A QF is responsible for all system Interconnection Facilities related costs and Network Upgrade costs. The QF shall be refunded its Network Upgrade related costs according to the terms and conditions of the applicable MISO tariff.

   Interconnection Facilities means the Company's or the Transmission Service Provider's Interconnection Facilities and the QF Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the QF and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   Network Upgrades are additions, modifications and upgrades to the Company's, Transmission Service Provider's or other affected parties' transmission system required at or beyond the point at which the QF interconnects with the transmission system to accommodate the interconnection with the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   The rates and terms and conditions set forth herein are subject to the provisions of the "Interconnection Cost Amortization Option" set forth in Rate 95.

4. 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.

5. The QF 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.

6. The QF has the option of contracting for either the "Standard Payment Option" or "Net Billing Option Rate 94" for purposes of computing payments as stipulated in the written contract.

7. Sales by the QF to the Company do not include the transfer of the RECs associated with the energy produced. The RECs shall remain with the QF to utilize at their discretion.

8. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

NET BILLING OPTION Rate 94

In addition to the parties' contract agreement, Company and Seller agree to the following net billing option:

1. Description: Under this option all purchases of energy from Seller by Company shall be considered on a net consumption basis, offsetting Company's purchases from Seller against its sales to Seller. If Company's sales to Seller are greater than its purchases from Seller in a billing period, Seller's net consumption shall be billed at the applicable retail rate and no further Avoided Cost Payments shall be made to Seller. If Company's purchases from Seller exceed its sales to Seller during a billing period, then the net purchases shall be purchased from Seller by Company pursuant to the applicable Avoided Cost Payments schedule. All purchases of capacity from Seller by Company will be considered on a net basis, offsetting Company's capacity purchases from Seller against its capacity sales to Seller on an hourly basis. Capacity payments will only be made if Company's energy purchases from Seller exceed its energy sales to Seller during a billing period.

2. Metering:
   (a) Energy: Company, at its expense, will install separate meters equipped with detents to measure its purchases from and sales to Seller.

   (b) Capacity: Company will make no Avoided Cost Payments for Capacity nor apply any offsets to its Demand charges for Capacity supplied by Seller unless such Capacity purchases by Company from Seller are separately metered. Such meters will be installed at Seller's expense.

3. Interconnection: Nothing herein shall relieve Seller from providing all necessary equipment for interconnection specified in the parties' contract.

4. Termination: If Seller fails to make any payments due to Company and Company is unable to recoup such overdue payments from Seller as an offset against Avoided Cost Payments for three consecutive months, the Net Billing Option shall automatically terminate and Company shall be entitled to its remedies under Montana Public Service Commission Rules (ARM 38.5.1401 et seq.).

5. Election: The election of the Net Billing Option is the sole prerogative of Seller. This option is merely an addendum to the parties' underlying standard contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' standard contract, the specific provision in this option controls.

INTERCONNECTION COST AMORTIZATION OPTION Rate 95

In addition to the parties' contract agreement, Company and Seller agree to the following interconnection cost amortization option:

1. Description: Under this option, Seller's obligation to reimburse Company for its cost of interconnection with Seller shall be made in monthly installments, such installments to include a finance charge as provided herein.

2. Finance Charge: Company's Cost of Interconnection shall be deemed to be the principal amount due and owing Company by Seller. The term of the loan shall be deemed to be the class life used by the Company for depreciating the special facilities required for interconnection or the length of the parties' contract, whichever is shorter. Seller shall repay the principal to Company in equal monthly installments over the term of the loan. Seller shall pay to Company each month interest on the unpaid balance computed, on an annual basis, to be equal to the incremental cost of capital to Company as of the date of the execution of this agreement. The incremental cost of capital to Company shall consist of the last cost of equity capital authorized by the Montana Public Service Commission, the current cost of new debt issues rate similarly to the bonds issued by Company, and the last cost of preferred stock experienced by Company.

3. Mortgage Requirement: Seller shall execute a first mortgage upon the Seller's property in favor of Company securing to Company full payment of all amounts due Company under this financing arrangement. In the event of a prior mortgage commitment, Seller shall secure for Company an adequate subordination agreement placing the mortgage required herein in a first position.

4. Nonpayment by Seller: In the event of nonpayment by Seller of any monthly installment due Company under this financing arrangement, Company may:
   (a) Offset the late payment against any amount due Seller from Company and thereafter deduct from each month's payments due Seller from Company an amount sufficient to cover the next month's installment of principal and interest due Company under this financing arrangement.

   (b) In the event the nonpayment exists for three consecutive months, declare the entire principal amount due and owing, together with any interest accrued thereon, declare the Seller in default, and exercise its rights under the parties' mortgage, and cease interconnection with Seller as a qualifying facility.

5. Necessary Documents: Seller shall execute all documents deemed necessary by Company to perfect a secured load transaction including, but not limited to, a note, mortgage, and Truth in Lending disclosure statement. Upon satisfaction of all of Seller's obligations under this financing arrangement, Company shall promptly release its mortgage interest in the property of the qualifying facility.

6. Election: The election of the Interconnection Cost Amortization Option shall be the sole prerogative of Seller. Seller's election shall be manifested by the parties' separate execution of this option. This option is merely an addendum to the parties' contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' contract, the specific provision in this option controls.

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

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I. PURPOSE and APPLICABILITY:

This tariff is intended to provide the interconnection rules and procedures for any distribution customer of Montana-Dakota Utilities Co. (Montana-Dakota) located in the State of Montana proposing to install and interconnect a small generator facility to Montana-Dakota Electric Distribution System (EDS). The Small Generator Facility's nameplate capacity must be less than or equal to 10 MW and satisfy the following criteria:

1. The proposed small generator facility must be located on a utility customer's premise.
2. The customer installing the small generator facility must be in good standing with the Company.
3. The proposed small generator facility's point of interconnection may not be on a transmission line.
4. The power produced from the small generation facility must be contained on the Company's EDS and not flow onto Montana-Dakota's Electric Transmission System (ETS).
5. The power produced by the small generation facility must be intended to be utilized by the customer or sold to Montana-Dakota.

Generators that are proposed and designed for interconnection to the Company's ETS (interconnections to voltages above 25KV) or to deliver power to the Company's ETS are not covered under this scope of this tariff.

II. DEFINITIONS:

The following terms used in this tariff have the following meanings, except where the context clearly indicates otherwise:

APPLICANT - A person or entity that has filed an application to interconnect a customer generator to Montana-Dakota's Electric Distribution System (EDS). An applicant may include a third party who owns and operates a small generator facility under agreement with a customer or leases a small generator facility to a

customer.

COMMISSION - Public Service Commission of the State of Montana

CUSTOMER - Any entity connected to the utility system for the purpose of receiving electric power from the Company

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

CUSTOMER-GENERATOR - A customer that generates electricity, typically on the customer's side of the meter.

ELECTRIC DISTRIBUTION SYSTEM (EDS) –

1. The infrastructure constructed, maintained, and under the jurisdiction of Montana Dakota Utilities Co.
2. Electric Distribution System has the same meaning as the term Area EPS, as defined in 3.1.6.1 of the IEEE Standard 1547-2003.

ELECTRIC DISTRIBUTION COMPANY (EDC) – An electric utility that distributes electricity to end users within the State of Montana and is subject to regulation by the Commission.

ELECTRIC TRANSMISSION SYSTEM (ETS) – Montana-Dakota's Electric System that operates at voltages above 25KV are defined as transmission for the purpose of this rate schedule.

EXPORT - Power flows past the point of interconnection onto the EDS.

GOOD STANDING - A customer's account is not in arrears.

IEEE - Institute of Electrical and Electronics Engineers.

IEEE STANDARDS - The standards published by the Institute of Electrical and Electronics Engineers.

INTERCONNECT - To connect a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION - The result of connecting a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION CUSTOMER - An applicant that has entered into an interconnection agreement with Montana-Dakota to interconnect a small generator facility and has interconnected that small generator facility to Montana-Dakota's EDS.

INTERCONNECTION EQUIPMENT – A group of components or an integrated system provided by the interconnection customer to connect a small generator facility to Montana-Dakota's EDS, including all interface equipment such as switchgear, protective devices, inverters, or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

INTERCONNECTION FACILITIES – The facilities and equipment required by Montana-Dakota to accommodate the interconnection of a small generator facility to Montana-Dakota's EDS and used exclusively to interconnect a specific small generator facility. Interconnection facilities do not include system upgrades that may benefit Montana-Dakota, other customers, other interconnection customers, or an owner of an affected system.

LINE SECTION - The portion of a radial distribution circuit to which an applicant seeks to interconnect and is bounded by sectionalizing devices or is located at the end of a distribution line.

NAMEPLATE CAPACITY - The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer and is usually indicated on a nameplate physically attached to the power production equipment.

NATIONALLY RECOGNIZED TESTING LABORATORY (NRTL) - A testing laboratory that is recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards.

NON-CONTINOUS PARALLEL GENERATOR – A generator that is designed to parallel the EDS for a short time period during a transfer of load for periods typically less than two minutes. This includes High Speed Transfer Switch Interconnections, Closed Transfer Systems, or Hot Transfer Standby Generator designs. The application process for this type of request will require the same process as a Continuous Parallel Generator. Some interconnection requirements may be relaxed, and an Interconnection Agreement may not be required, as determined on a case by case basis.

RADIAL DISTRIBUTION CIRCUIT - A circuit configuration in which independent feeders branch out radially from a common source of supply. In a radial distribution system, power flows in one direction from the company substation feeder to the load.

SMALL GENERATOR FACILITY - An energy resource(s) for the production and/or storage of electricity on the utility customer's premises that have an aggregate nameplate capacity that is less than or equal to 10 MW.

WITNESS TEST – A test performed jointly with Montana-Dakota to verify basic functionality of the small generator equipment and that the installation operates within acceptable limits of operation and does not interfere with the safety and operation of the EDS.

III. REQUEST FOR INTERCONNECTION:

1. INTERCONNECTION REQUEST:
   An applicant wanting to interconnect a small generator facility to the Company's EDS shall submit a Small Generator Facility Distribution Interconnection Application Form to Montana-Dakota.

   The applicant must determine, prior to the submission of an application, the Interconnection Level the project will be submitted under. A preliminary consultation with Montana-Dakota personnel is recommended to help simplify the process prior to submitting an application form.

2. QUEUE POSITION:
   Upon the receipt of an interconnection application request, Montana-Dakota shall assign a queue number in order to establish precedent with other existing and future interconnection requests on the same distribution circuit. The queue position of the interconnection request shall be used to determine the potential adverse system impacts of the small generator facility based on the relevant screening due to the nature of where a project is listed within the queue on a particular circuit. This will be communicated on the request acknowledgement form sent back to the applicant after the receipt of an application.

3. AGGREGATION OF MULTIPLE GENERATORS –
   a. An interconnection request for a small generator facility that includes multiple energy production devices at the common site where the applicant seeks a single point of interconnection shall be evaluated on the basis of the total aggregate nameplate capacity of the multiple devices.

   b. An interconnection request for an increase in the capacity for an existing small generator facility shall be evaluated using the new total aggregate capacity of the generators at the interconnection site.

4. FEE SCHEDULE:
   Interconnection applications must include a non-refundable application fee for Level 1 and 2 interconnection requests or a refundable deposit for Level 3 and 4 interconnection requests. The amount of the fee is dependent on the review level procedures of the interconnection request. All fees or deposits for processing such request must be paid prior to acceptance of the interconnection request by the Company.

Level 1 Application Fee -	$ 50.00
Level 2 Application Fee -	$200.00
Level 3 Application Deposit -	$500.00
Level 4 Application Deposit -	$500.00

   Interconnection Review Levels 1, 2, 3, and 4 are defined in Section III.7 of this tariff.

5. MODIFICATION OF APPROVED APPLICATION:
   When an interconnection request is deemed complete between Montana-Dakota and an applicant, any modification or change to the completed interconnection not agreed to by Montana-Dakota in writing shall require the submission of a new interconnection application request.

6. CERTIFIED EQUIPMENT:
   Interconnection application requests may be eligible for review procedures as outlined below in this tariff if the small generator facility uses certified interconnection equipment.
   a. Interconnection equipment shall be deemed certified upon the establishment of all the following:
      i. The interconnection equipment has been labeled and is publicly listed by a National Recognized Testing Lab (NRTL) at the time of the application.
      ii. The equipment must have certification testing results available from the manufacturer or NRTL upon request of the Company.

iii. The applicant must verify and provide information that the certified interconnection equipment is compatible with the generator and that the planned use of the certified interconnection equipment falls within the labeled and certified use and limits listed by the manufacturer.

iv. The interconnection equipment must be evaluated by a NRTL in accordance with the following codes:

1. IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems using the testing protocol IEEE 1547.1-2005 Standard testing procedures to establish conformity.
2. UL 1741 Standard Inverters, Converters, and Controllers for Use in Independent Power Systems.

7. INTERCONNECTION REVIEW LEVELS:
Interconnection application requests shall be reviewed using one of the following four procedures, based on size, complexity, and characteristics of the project:

a. Level 1 – Small Generator Facility – Certified Inverter Connected up to 50 KW: applicable to proposed customer generation interconnections where the generator size is 50 KW or less and the generated power is to be interconnected to the radial EDS utilizing Certified Inverter Equipment.

b. Level 2 – Small Generator Facility – Certified Equipment Connected up to 2 MW: applicable to proposed customer generation interconnections where the generator size is 2 MW or less and the generated power is to be connected to the radial EDS utilizing Certified Inverter Equipment.

Interconnection requests previously submitted under Level 1 but not approved under Level 1 may be reviewed as a Level 2 request under a new interconnection request for consideration.

c. Level 3 – Small Generator Facility – No Power Export – Up to 10 MW: applicable to proposed customer generation interconnections where the size

of the equipment is less than 10 MW and the generated power is planned for customer load with no power exported to the Company's EDS.

Interconnection requests previously submitted under Level 2 but not approved under Level 2 may be reviewed as a Level 3 request under a new interconnection request for consideration.

d. Level 4 – Small Generator Facility – Up to 10 MW: applicable to proposed customer generation interconnections where the size of the generation is less than 10 MW and the interconnection request does not meet the criteria for review under Levels 1, 2, or 3, or was not approved under Interconnection requests previously submitted for review under Levels 1, 2, or 3.

IV. LEVEL 1 REVIEW PROCEURES:

An application interconnection request submitted under Level 1 shall be subject to the following review procedures:

1. The Level 1 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and shall indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:

a. Verify that the Interconnection Inverter Equipment Certification is valid and proper.
b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
   i. 15% of the peak load on the line section
   ii. The annual minimum load for the line section
c. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
d. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
e. The proposed small generator facility shall not exceed the capacity of the existing electrical service.
f. The Level 1 application cannot require any construction modifications to the Company's EDS

4. The Company shall, within 15 business days of an interconnection application being deemed complete, provide verification that the small generator facility equipment can be interconnected safely and reliably using Level 1 screens.

5. Within 5 business days of an approved Level 1 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   b. The Witness Test has been performed and successfully completed.

7. If the Level 1 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 1 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 2, Level 3, or Level 4 review. The line section queue position assigned to the Level 1 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

V. LEVEL 2 REVIEW PROCEURES:

An application interconnection request submitted under Level 2 shall be subject to the following review procedures:

1. The Level 2 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:
   a. Verify that the Interconnection Inverter/Equipment Certification is valid and proper.
   b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
      i. 15% of the peak load on the line section
      ii. The annual minimum load for the line section

c. The proposed small generator facility, in total with other generation on the distribution circuit, must not contribute more than 10% to the maximum fault current at the point on the primary line nearest the point of interconnection.
d. The proposed small generator facility, in total with other generation on the distribution circuit, must not cause any distribution protective devices and equipment, or other customer equipment on the EDS to be exposed to fault currents exceeding 90% of the short circuit interrupting capability including X/R effects.
e. The proposed small generator facility, in total with other generation interconnected to the primary distribution side of a substation transformer feeding the circuit, may not exceed 10 MW in an area where there are known transient stability limitations to generating units located in the general electrical vicinity.
f. When a three phase three wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected phase-to-phase.
g. When a three phase four wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected line-to-neutral and shall be effectively grounded.
h. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
i. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
j. The proposed small generator facility must not exceed the capacity of the existing service.
k. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company shall, within 20 business days of an interconnection application being deemed complete:
   a. Evaluate the request using the Level 2 review criteria

b. Review the applicant's analysis, if provided by the applicant, using the same criteria, and
c. Provide the applicant the Company's evaluation, including a comparison of the results of its own analysis with those included with the application.

5. Within 5 days of an approved, or conditionally approved Level 2 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. For approved requests, the Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   b. The Witness Test has been performed and successfully completed.

7. A conditionally approved interconnection application is an interconnection request that may be approved under Level 2 criteria with minor modifications to the Company's EDS, however the application has failed one or more of the evaluation elements listed previously. The Company will provide the applicant with a letter that includes an Interconnection Agreement and a listing of the milestones needed to be completed for the facility to be connected to the Company's EDS.
   a. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions being completed:
      i. All milestones agreed to the in the Interconnection Agreement are satisfied.
      ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
      iii. A Witness Test has been performed and successfully completed.

8. If the Level 2 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 2 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 3 or Level 4 review. The line section queue position assigned to the Level 2 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VI. LEVEL 3 REVIEW PROCEURES:

An application interconnection request submitted under Level 3 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the interconnection request using the following criteria:
   a. The total of the nameplate capacity of all generators on the circuit, including the proposed small generating facility, is 10 MW of less.
   b. The small generator will use reverse power relays or other protection that prevent power flow onto the EDS.
   c. The small generator facility is not served by a shared transformer.
   d. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company will evaluate the application and provide a response to the Applicant within 20 business days of a completed application form.

5. Within 5 days of an approved Level 3 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned by the interconnection applicant within 30 business days from the receipt of the response or deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. All milestones agreed in the Interconnection Agreement are satisfied.
   b. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   c. The Witness Test has been performed and successfully completed.

7. If the Level 3 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 3 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 4 review. The line section queue position assigned to the Level 3 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VII. LEVEL 4 REVIEW PROCEURES:

An application interconnection request submitted under Level 4 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the Applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. A Level 4 application that is deemed incomplete shall have 10 business days to provide the data necessary to complete the interconnection request or the application will be deemed withdrawn from the process.

4. Once the Interconnection Application is deemed complete, the Company shall use the following metrics in performing a Level 4 review:
   a. With an agreement between the parties, the scoping meeting, interconnection feasibility study, interconnection impact study, or interconnection facilities study provided for in a Level 4 review may be waived.

   b. If agreed to by the parties, a scoping meeting will be held within 10 business days of the notification to the applicant that the interconnection application is complete, or the applicant has requested that its interconnection request proceed after failing the requirements of a Level 2 or Level 3 review.

   c. The scoping meeting will provide what is needed to proceed with a feasibility study and any further analysis of the proposed generator interconnection request. Any previous study results or other pertinent information will also be reviewed at the scoping meeting to determine the need for additional studies.

   d. An Interconnection Feasibility Study may be performed to determine if the project is feasible to interconnect with Montana-Dakota's EDS.

      If the parties agree that an Interconnection Feasibility Study shall be performed, the Company shall provide to the applicant, no later than 5

business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Feasibility Study shall include any of the following analyses necessary for the purpose of identifying any potential adverse system impacts on the EDS:

i. Initial identification of circuit breaker short circuit limits exceeded.
ii. Initial identification of any thermal overload issues
iii. Initial identification of any voltage limit issues
iv. Initial review of any grounding requirement and system protection concerns
v. A non-binding rough estimate of the costs of facilities required to interconnect the proposed generator to the EDS.

e. An Interconnection System Impact Study may be performed to review the system impacts of the proposed small generator on Montana-Dakota's EDS.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study is not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection System Impact Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

An Interconnection System Impact Study shall evaluate the impact of a proposed small generator on the Company's EDS on both the reliability and safety issues related to the proposed generator. Consideration of any studies that an applicant has provided will be reviewed and analyzed. The impact study shall include any necessary elements from among the following:

i. A load flow study
ii. Identification of the affected systems
iii. An analysis of equipment interrupting ratings
iv. A protection coordination study

v. Voltage drop and flicker studies
vi. Grounding reviews
vii. System operations impacts
viii. A short circuit analysis
ix. A stability analysis

f. An Interconnection Facilities Study shall be performed to estimate the cost of the equipment, engineering, procurement, and construction work, including overheads, needed to implement the conclusions of the Interconnection Feasibility Study and/or the Interconnection System Impact Study to interconnect the proposed small generator facility.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study and an Interconnection System Impact Study are not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection Facilities Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Facilities Study shall identify the following:

i. The electrical switching configuration of the equipment, including transformer, switchgear, meters, and other station equipment.
ii. The nature and estimated cost of the Company's EDS changes required to interconnect the proposed small generator facility.
iii. An estimate of the time required to complete the construction and installation of the required facilities on the EDS.

g. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection can be made to the EDS, the Company will send a response letter to the applicant with an Interconnection Agreement for Small Distribution Generator Facility, including the requirement details associated with the proposed installation.

h. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection cannot be made to the EDS, the Company will send a response letter to the applicant indicating the reasons for the denial of the application.

i. The applicant will have 30 business days after the receipt of an interconnection agreement to sign and return the agreement. When an applicant does not sign and return the application within 30 business days, the interconnection request shall be deemed withdrawn.

j. The interconnection agreement will be final only when:
   i. The milestones agreed to in the Interconnection Agreement for Small Distribution Generator Facility are satisfied.
   ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   iii. The Witness Test has been performed and successfully completed.

VIII. GENERAL INTERCONNECTION PROVISIONS:

1. APPLICANT'S RESPONSIBILITY:
   a. The interconnection applicant is responsible for the construction of all generator facilities and the securing of any necessary approvals or permits from local, state, and federal authorities.

   b. The costs associated with the interconnection application and agreement are the responsibility of the interconnection applicant. This includes any application fees, the cost of various studies required, and any construction of facilities on the Electric Distribution System needed to accommodate a proposed small generator facility. The Company will not charge the applicant for the required Witness Test.

2. Existing capacity or construction of capacity by the Company on its EDS is not required to accommodate small generator facilities.

3. Interconnection facilities approved and installed under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

4. DISCONNECTION DEVICE:
   The proposed interconnection design of a Small Generator Facility must include a disconnect device installed, owned, and maintained by the customer to be used by the Company in the event of system operation maintenance or an emergency event. The disconnect device shall be capable of interrupting and isolating the small generation facility equipment from the Company's EDS. This device must allow for a visible break, must have the ability to be locked open, and must be accessible to the Company at all times for use. The location shall be within ten (10) feet of the metered service point unless special permission is granted by Montana-Dakota. The disconnection device shall be documented on the Interconnection Agreement.

5. METERING:
   Changes to or the addition of metering equipment to properly account for the generation and use of power at the interconnection site will be communicated by the Company in the application process. The customer will be responsible for the installation, costs, and maintenance of any load wiring, meter sockets, cabinets, etc. required for the accommodation of meters, instrument transformers, test switches, or other meter devices provided by and maintained by the Company. The additional or required metering changes shall be documented on the Interconnection Agreement.

6. TECHNICAL STANDARDS:
   Unless otherwise noted in this tariff, the technical standard to be used in evaluating all interconnection requests shall be the IEEE Standard 1547-2003 version.

7. WITNESS TEST:
   A witness test shall be required as part of the installation and approval of any proposed interconnection to the Company's EDS. This test is required to assure the small generator facility is operating within the characteristics of the equipment as proposed and certified along with an assurance that no operational interference is affecting any other customer's service on the Company's EDS. The applicant shall give the Company a 10-day notice to schedule this Witness Test of the small generator facility. This test may be performed at the commissioning startup of the proposed facility and a successful test is required to gain final approval of the interconnection agreement.

   The Witness Test at a minimum shall require:
   a. Verification of the Equipment proposed and declared on the Application Request.
   b. Verification of the location and access of the Disconnection Device.
   c. A Power Recording Device installation at the interconnection point to record a period of time the small generator facility is operating in parallel to the EDS.
   d. Verify that a loss in EDS voltage to the system allows for proper interruption of the generation voltage to the EDS. (Islanding Test)
   e. Any other test stipulated in the Interconnection Agreement.

   If the witness test is not acceptable, the Company shall send a written report to the applicant within 5 business days of the end of the witness test period. The applicant shall be granted 30 business days to address and resolve any deficiencies. If the applicant fails to address and resolve the deficiencies to the satisfaction of the Company, the interconnection request will be deemed withdrawn.

8. INSPECTION AND TESTING OF FACILITY:
   a. Future testing of an approved facility may be performed under the following circumstances:
      i. An annual test for Level 2 and Level 3 approved facilities

ii. Mutually agreed upon intervals for Level 4 approved facilities and any necessary testing specified by the manufacturer.

b. The Company shall have the right to inspect a customer generator facility before and after the interconnection approval is granted. This right to inspection is to be performed at reasonable hours and with reasonable prior notice provided to the customer.

9. MONITORING OF INTERCONNECTION EQUIPMENT:
The Company may require monitoring or control of a small generator facility if the nameplate capacity rating of the small generator facility interconnecting to the EDS, or the aggregate nameplate capacity of all small generator facilities on the line section in combination with the proposed small generator facility interconnecting to the EDS, is greater than 15% of the line section annual peak load as most recently measured at the substation or exceeds the annual minimum load of the line section.

10. DISCONNECTION OF SERVICE:
   a. The Company shall have the right to disconnect the customer generator facility at any time during an emergency on the EDS.
   b. If the Company discovers that the customer generator is not in compliance with the requirements of IEEE Standard 1547-2003, and the noncompliance adversely affects the safety or reliability of the EDS, the Company may require the disconnection of the customer generator facility until it complies. The Company will provide the customer with a written report of the details of how the customer generator facility is not complying with IEEE 1547-2003 or the Administrative Rules of the State of Montana (Small Generator Interconnections).
   c. The Company shall have the right to disconnect unauthorized small generator interconnections to the Company EDS upon discovery.

11. DISPUTE RESOLUTION:
    Either the Company or Customer Generator shall attempt to resolve all disputes regarding a small generator facility interconnection promptly, equitably, and in a good faith manner.

    When a dispute cannot be resolved, a party may seek immediate resolution through complaint procedures available through the Montana Public Service Commission.

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 1)

APPLICATION SCOPE:

LEVEL 1 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 50 KW in size utilizing inverter based certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96).

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Small Generator Facility Information

INVERTER

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for inverters by a Nationally Recognized Testing Laboratory (NRTL)

GENERATOR

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐ Turbine ☐

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐ Fuel Oil ☐

Generator Comments ______

Total System Design Capacity: ______ (KW) ______ (KVA)

SITE Information

This application is requested for: ☐ A New Small Generator to be located on an Existing Service.
☐ A New Small Generator to located at a New Service.
☐ A Change to an Existing Small Generator Location

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Estimated Commissioning Date: ______

Interconnection Address/Location: ______

MDU Premise/Account (MDU USE): ______

Note: The Required Disconnect Switch must be able to be locked open and shall be located within 10 (Ten) feet of the meter location unless special permission is granted by the company.

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach a One-Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), and Disconnect Switch.

☐ - Completed Net Metering Application Addendum "A"

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $50.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Title: ____________________ Date: ____________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate: YES☐ NO ☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 2)

APPLICATION SCOPE:

LEVEL 2 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 2 MW in size and must utilize certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96). Also, Interconnections that were reviewed under Level 1 review procedures but not approved, can be re-submitted under a new Level 2 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

SITE INFORMATION

This application is requested for: ☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location:

MDU Premise/Account (MDU USE ONLY):

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: Amps Voltage: Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date:

Small Generator Facility General Information

Prime Mover: Photovoltaic ☐
Reciprocating Engine ☐
Fuel Cell ☐
Turbine ☐
Micro Turbine ☐
Other ____________

Energy Source: Solar ☐
Wind ☐
Hydro ☐
Diesel ☐
Natural Gas ☐
Steam ☐
Fuel Oil ☐
Other ____________

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Generator Nameplate Rating: ______ KW ______ KVAR

Total Expected Generation Export ______ KW ______ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ______ (KW) ______ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

CERTIFIED EQUIPMENT LISTING - List interconnection components/systems to be used in the Small Generation Facility that is NRTL Certified. (required for Lab Tested Certification of Interconnection Equipment) Please inclued information for all certified equipment components.

Component/System	NRTL Providing Label - Listing

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach Information from All Other Certified Interconnection Equipment Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Complete Net Metering Application Addendum "A" (If Applicable)

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ Attach a One-Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $200.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________________

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Title: ______________________ Date: ______________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate 92: YES☐ NO ☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

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Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer: ____________

Model Number: ____________ Version Number: ____________

* **Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non-Salient Rotor ☐

Torque: ______ Ft-Lb Rated RPM: ______

At Rated Generator Voltage and Current: Field Amperes: ______ Amps @ ______ %PF

Type of Exciter: ____________

Output Power of Exciter: ____________

Type of Voltage Regulator: ____________

Locked Rotor Current: ______ Amps Synchronous Speed: ______ RPM

Winding Connection: ____________

Min. Operating Frequency/Time: ____________

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): ______ Ohms (P.U.)

Direct-axis Transient Reactance (X'd): ______ Ohms (P.U.)

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Level 2 Interconnection Request Application Form

Direct-axis Sub Transient Reactance (X"d): ______ Ohms (P.U.)

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

Locked Rotor Current: ______ Amps Base KVA: ______ KVA

Rotor Resistance (Rr): ______ Ohms Exciting Current: ______ Amps

Rotor Reactance (Xr): ______ Ohms Reactive Power Required: ______

Magnetizing Reactance (Xm): ______ Ohms ______ VAR's (No Load)

Stator Resistance (Rs): ______ Ohms ______ VAR's (Full Load)

Stator Reactance (Xs): ______ Ohms

Short Circuit Reactance (Xd): ______ Ohms

K (Heating Time Constant): ______ Total Rotating Inertia H: ______ KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: ______ Design Letter: ______ Temp. Rise: ______ °C

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Levels 3 & 4)

APPLICATION SCOPE:

LEVEL 3 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 MW in size and where power will not be exported beyond the interconnection point. This could be used as a demand control generator for customer load.

LEVEL 4 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 Megawatts (MW) in size, and does not qualify under the criteria of LEVEL 1, LEVEL 2, and LEVEL 3. This includes any Interconnection Request that was submitted and not approved under a LEVEL 1, LEVEL 2, or LEVEL 3 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

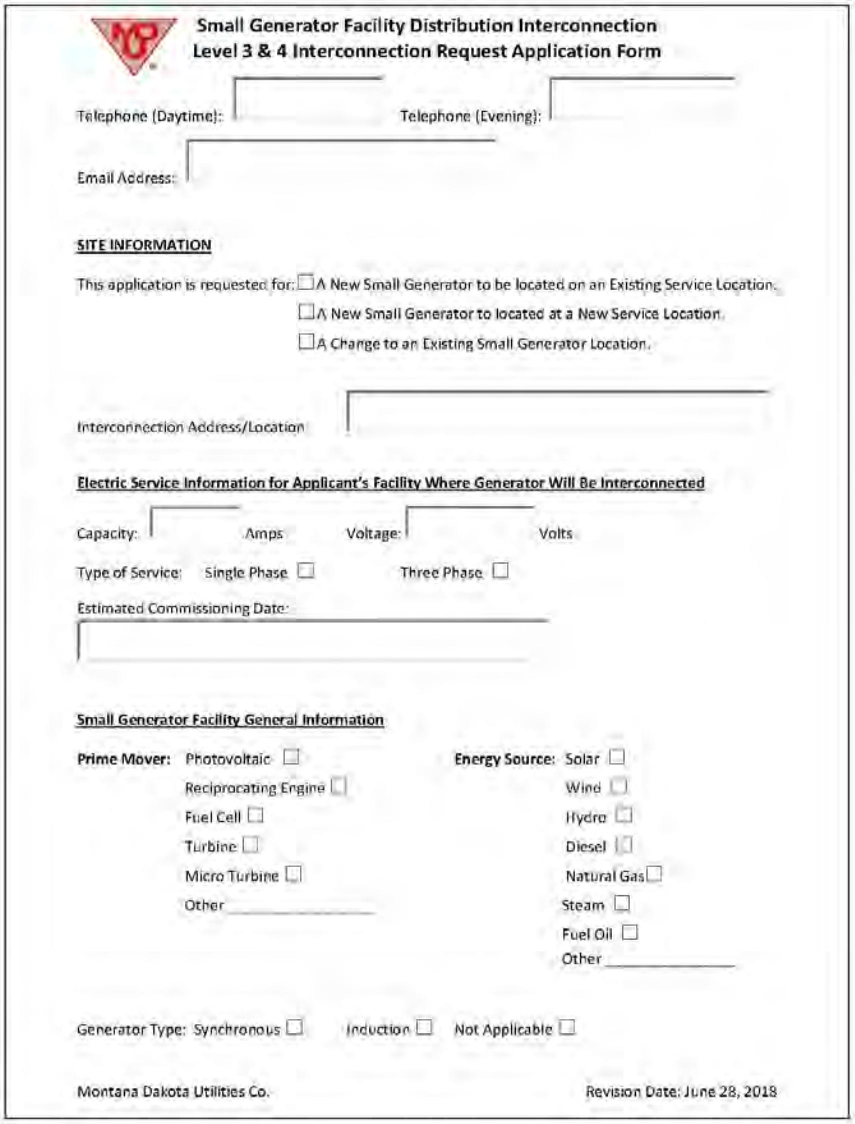
Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Montana Dakota Utilities Co. Revision Date: June 28, 2018



Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Telephone (Daytime): ______ Telephone (Evening): ______

Email Address: ______

SITE INFORMATION

This application is requested for: ☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location ______

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: ______ Amps Voltage: ______ Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date:

______

Small Generator Facility General Information

Prime Mover: Photovoltaic ☐
Reciprocating Engine ☐
Fuel Cell ☐
Turbine ☐
Micro Turbine ☐
Other ______

Energy Source: Solar ☐
Wind ☐
Hydro ☐
Diesel ☐
Natural Gas ☐
Steam ☐
Fuel Oil ☐
Other ______

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Generator Nameplate Rating: ______ KW ______ KVAR

Total Expected Generation Export ______ KW ______ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ______ (KW) ______ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes. (If Applicable)

☐ - Complete Equipment Detail Addendum "A" – Prepare Lists and Attach Detailed Information.

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ - Attach a Site Diagram of the Proposed System location indicating the locations of all proposed equipment at the Small Generator Site. This should include at a minimum, generator locations, electrical equipment, disconnect location, transformers, meters, and all other system related locations.

☐ - Attach a One-Line Diagram of the Proposed System that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch. Also include relay protection, control schematics, current and potential circuits, and alarm/monitoring circuits.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC: ______

Note: An application Deposit is required before the application can be processed. The actual cost of the studies and reviews necessary to provide for this Interconnection is the responsibility of Interconnection Applicant.

Application Deposit Included: ☐ Amount: $500.00 Deposit

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________________

Title: ______________ Date: ______________

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

GENERATOR CONNECTION

Transformer

Is there a Transformer needed between the Generator and Service Connection Point Yes ☐ No ☐

Transformer Detail: 3 Phase ☐ 1 Phase ☐

Capacity: ____ KVA Impedance: ____ % on BASE: ____ KVA

PRIMARY: Voltage: ____ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

SECONDARY: Voltage: ____ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

Power Circuit Breaker

Manufacturer: ____

Type: ____

Load Amp Rating: ____ Interrupting Amp Rating: ____

Trip Speed: ____ Cycles

Interconnection Relays

If Conventional individual relay: Attach a List and Include the following for each relay:

Manufacture, Model, Catalog Number, Function, Proposed Setting

If Microprocessor Controlled: List the following for each Setpoint:

Setpoint Function, Minimum, and Maximum Settings – Proposed Settings.

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

Auxiliary Transformers

Current Transformers (If Applicable and for each Bank of Current Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, and Burden.

Potential Transformers (If Applicable and for each Bank of Potential Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, Thermal Rating, and Burden.

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer:

Model Number: Version Number:

*** Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non-Salient Rotor ☐

Torque: Ft-Lb Rated RPM:

At Rated Generator Voltage and Current: Field Amperes: Amps @ %PF

Type of Exciter:

Output Power of Exciter:

Type of Voltage Regulator:

Locked Rotor Current: Amps Synchronous Speed: RPM

Winding Connection:

Min. Operating Frequency/Time:

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): Ohms (P.U.)

Direct-axis Transient Reactance (X'd): Ohms (P.U.)

Direct-axis Sub-Transient Reactance (X"d): Ohms (P.U.)

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Level 3 & 4 Interconnection Request Application Form

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer:

Model Number: Version Number:

Locked Rotor Current: Amps Base KVA : KVA

Rotor Resistance (Rr): Ohms Exciting Current: Amps

Rotor Reactance (Xr): Ohms Reactive Power Required:

Magnetizing Reactance (Xm): Ohms VAR's (No Load)

Stator Resistance (Rs): Ohms VAR's (Full Load)

Stator Reactance (Xs): Ohms

Short Circuit Reactance (Xd): Ohms

K (Heating Time Constant): Total Rotating Inertia H: KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: Design Letter: Temp. Rise: °C

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Small Generator Facility Distribution Interconnection

Interconnection Feasibility Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ____ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Feasibility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection Feasibility Study as Attachment "A" attached to this agreement.

4. The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Applicant in its Application, as may be modified as the result of the Scoping Meeting. Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility

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Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application, the time to complete the Interconnection Feasibility Study may be extended by mutual agreement of the Parties.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The Feasibility Study and Report will include the following analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

ii. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

iii. Initial review of grounding requirements and system protection; and

iv. A Description and non-binding estimated cost of facilities required to interconnect the Small Generator Facility to Montana-Dakota's Electric Distribution System in a safe and reliable manner.

7. The Interconnection Feasibility Study shall be completed and the results transmitted to the Interconnection Applicant within 30 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Feasibility Study Report within the 30-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

8. The Interconnection Applicant is responsible for the Feasibility Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Feasibility Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Small Generator Facility Distribution Interconnection

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed): ______________________________

Signed: ______________________________

Title: ______________________________

Date: ______________

[Insert name of Applicant]

Name (Printed): ______________________________

Signed: ______________________________

Title: ______________________________

Date: ______________

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Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions in regard to a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection Feasibility Study Estimated Cost: $

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Small Generator Facility Distribution Interconnection

Interconnection System Impact Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ____ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________, and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"), and

Whereas, Montana-Dakota has completed a Small Generator Interconnection Feasibility Study and provided the results in the form of a Report to the Interconnection Applicant or the Feasibility Study was waived by mutual agreement of the Parties, and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection System Impact Study to assess the impact of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System;

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with Initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection System Impact Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection System Impact Study as Attachment "A" and attached to this agreement.

4. The Interconnection System Impact Study shall be based on the technical information provided by the Interconnection Applicant in its Application, results of the Feasibility Study Report (if performed), and any information agreed upon as a result of the Scoping Meeting. Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the System Impact Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application Information or the technical information, the time to complete the Interconnection System Impact Study may have to be extended.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The System Impact Study will include the following detailed analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Short Circuit Analysis
ii. A Power Flow Analysis
iii. Verification of Interruption Equipment Ratings
iv. Protection Coordination Study
v. Voltage Drop and Flicker Study
vi. Effective Grounding Review
vii. System Stability Analysis
viii. Review of Set Points of Certified Equipment
ix. A Review of the Interconnection Impact on the EDS Operations.

7. The System Impact Study Report shall state the assumptions upon which it is based, state the results of the analyses, indicate any interconnection requirements or impediments, and will include preliminary changes and costs required to the Montana-Dakota Electric Distribution System in order to implement the Interconnection request. The System Impact Study preliminary changes and costs will include a list of facilities and changes that are required as a result of the Interconnection request and a non-binding good faith estimate of cost responsibility and time to construct.

8. The Interconnection System Impact Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Interconnection System Impact Study within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

Small Generator Facility Distribution Interconnection

9. The Interconnection Applicant is responsible for the Interconnection System Impact Study costs. The Study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection System Impact Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

[Insert name of Applicant]

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection System Impact Study Estimated Cost: $

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Small Generator Facility Distribution Interconnection

Interconnection Facilities Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ________________________________ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

__**Recitals:**__

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ________________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, Montana-Dakota has completed a Small Generator Interconnection System Impact Study and provided the results in the form of a Report to the Interconnection Applicant; and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Facilities Study to list and provide estimate for all the costs and timing of system changes to implement the conclusions of the Interconnection System Impact Study in order to safely Interconnect the proposed small generator to the Electric Distribution System. This estimate would include any distribution equipment, metering equipment, operational impacts, or other costs associated with the operation of the new proposed interconnection on the Montana-Dakota Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Facility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information specific to or affecting the Interconnection Facilities Study as Attachment "A" and filed with this agreement.

4. The Interconnection Facilities Study shall include a detailed specification and listing of any system equipment, metering equipment, operational costs (including overheads), or other costs (including overheads) required to safely interconnect the proposed small generator interconnection to the Montana-Dakota Electric Distribution System. Details of the Interconnection Facilities Study Report will include a listing of the required equipment, the electrical configuration of the Interconnection system estimate, an estimate of the specific costs of each item, and the estimate of the timing required to performing the system changes estimated for the interconnection.

5. The Interconnection Facilities Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Facilities Study Report within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

6. The Interconnection Applicant is responsible for the Interconnection Facilities Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection Facilities Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Small Generator Facility Distribution Interconnection

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):______________________________

Signed: ______________________________

Title: ______________________________

Date: ________________

[Insert name of Applicant]

Name (Printed):______________________________

Signed: ______________________________

Title: ______________________________

Date: ________________

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Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, Feasibility Study, System Impact Study, or agreed upon details between the parties.

Scoping Meeting Date. ______________________________

Interconnection Facilities Study Estimated Cost: $

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

This Interconnection Agreement ("Interconnection Agreement" or "Agreement") is entered into effective as of Click or tap to enter a date., ("Effective Date") by and between Click or tap here to enter the name of the Applicant for this Interconnection Agreement., ("Applicant") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

<u>Recitals</u>:

Whereas, the Applicant is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on ***Click or tap to enter a date.***;

Whereas, the Applicant desires to interconnect the Small Generator Facility with the Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, the Agreement shall be used for all approved Level 1, Level 2, Level 3, and Level 4 Applications according to the terms and procedures set forth in Montana-Dakota's Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff (Rate 96). Terms with initial capitalization, when used in this Agreement, shall have the meanings given in Rate 96 and, to the extent this Agreement conflicts with Rate 96, the Rate 96 tariff shall take precedence.

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

<u>Article 1.</u> Scope and Limitations of Agreement

1.1 Scope

The Agreement establishes standard terms and conditions approved by the Montana Public Service Commission (the "Commission") under which the Small Generator Facility with a Name Plate Capacity of 10 MW or smaller will interconnect to, and operate in Parallel with Montana-Dakota's EDS. Additions, deletions, or changes to the standard terms and conditions of an Interconnection Agreement will not be permitted unless they are mutually agreed to by the Parties and approved by the Commission if required by Rate 96.

1.2 Power Purchase

The Agreement does not constitute an agreement to purchase or deliver the Applicant's power nor does it constitute an electric service agreement.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

1.2.1 **Other Agreements.**
Nothing in the Interconnection Agreement is intended to affect any other agreement between the Montana-Dakota and the Applicant or another Interconnection Customer. However, in the event that the provisions of the Agreement are in conflict with the provisions of other Montana-Dakota tariffs, the Montana-Dakota tariff shall control.

1.3 **Attachments to Interconnection Agreement**

An Operations and Maintenance Schedule shall be attached to the Interconnection Agreement and the Applicant shall adhere to that schedule. Either Party may require that any of the following addendums be included as part of the Interconnection Agreement:

(A) Copy of the Interconnection Application
(B) Description of the project;
(C) a Billing Schedule;
(D) a List of non-binding milestones for each party;
(E) Scope of Work;
(F Operational Guidelines; and
(G) List of Major Permits needed by the Applicant.
(H) Assignment Acknowledgement Agreement

1.4 **Responsibilities of the Parties**

The Parties shall perform all obligations of the Agreement in accordance with all applicable laws and rules.

The Applicant will construct, own, operate, and maintain its Small Generator Facility in accordance with the Agreement, the IEEE Standard 1547-2003 version, the most currently adopted National Electric Code, state and federal law, and all other applicable standards required by the Commission. Each Party shall be responsible for the safe installation, maintenance, repair, and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and personal injury.

To the extent applicable, the allocation of responsibility for the design, installation, operation, maintenance, and ownership of Interconnection Facilities shall be as prescribed in Rate 96.

1.5 **Parallel Operation and Maintenance Obligations**

Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of the Interconnection Agreement, the Applicant will abide by all written provisions for operation and maintenance as required by Montana-Dakota.

1.6 **Power Quality**

The Applicant will design its Small Generator Facility to maintain a composite

power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. Any special operating requirements will be detailed in an attached form. Under no circumstances shall these additional requirements for voltage or reactive power support exceed the normal operating capabilities of the Small Generator Facility.

Article 2 **Inspection, Testing, Authorization, and Right of Access**

2.1 Testing and Inspection

Applicant will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in Rate 96. The Interconnection will not be final until the Witness test and certificate of completion provisions in Rate 96 have been satisfied or waived in accordance with Rate 96.

To the extent that an Applicant decides to conduct interim testing of the Small Generator Facility prior to the witness test, it may request that the Montana-Dakota observe these tests and that these tests be deleted from the final witness test. If Montana-Dakota sends qualified personnel to the Small Generator Facility to observe such interim testing, it will be doing so at the Company's own expense.

2.2 Right of Access:

Montana-Dakota will have access to the Applicant's premises, at no cost, for any reasonable purpose in connection with the Interconnection Application, the Interconnection Agreement, or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency, hazardous condition, or violation of the terms of this agreement.

Article 3. **Effective Date, Term, Termination, and Disconnection**

3.1 Effective Date

The Agreement shall become effective upon the Effective Date stated in the introductory paragraph.

3.2 Term of Agreement

The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or another period mutually agreed to by Parties in a written amendment, unless terminated earlier by default of either Party, voluntary termination by the Interconnection Customer, or by action of the Commission.

3.3 Termination

The Applicant may terminate this Agreement at any time by giving Montana-Dakota twenty (20) business days written notice. Either Party may terminate

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this Agreement pursuant to Section 5.6.2 after default by the other Party. The Commission may order termination of this Agreement. Upon termination of this Agreement, the Small Generator Facility will be disconnected from Montana-Dakota's EDS at the Applicant's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination. The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 **Restoration of Interconnection When Disconnected**

The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Montana-Dakota's EDS to their normal operating state as soon as reasonably practicable following any disconnection pursuant to the rules.

<u>Article 4.</u> **Cost Responsibility and Billing**

The Applicant is responsible for the application fee, cost of studies, and for such facilities, equipment, modifications, and upgrades identified under the process prescribed in Rate 96.

4.1 **Minor EDS Modifications**

The Applicant will bear the costs of making minor modifications to Montana-Dakota's EDS as may be necessary to gain approval of an Application.

4.2 **Interconnection Facilities (Company Owned)**

When necessary under the process prescribed in Rate 96, Montana-Dakota will identify the interconnection facilities ("Interconnection Facilities") necessary to safely interconnect the Small Generator Facility with the EDS. Montana-Dakota will itemize the Interconnection Facilities for the Applicant, including the cost of the facilities and the time required to build and install those facilities. The Applicant is responsible for the cost of the operational changes or physical additions to the Company-owned Interconnection Facilities.

4.3 **Interconnection Equipment (Customer Owned)**

The Applicant is responsible for all costs associated with the installation, operation and maintenance of the interconnection equipment not owned by the Company

4.4 **System Upgrades**

Montana-Dakota will design, procure, construct, install, and own any System Upgrades under the process prescribed in Rate 96 when applicable. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Applicant. An Interconnection Customer may be entitled to financial compensation from other utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the

Commission or by terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 Adverse System Impact

Montana-Dakota is responsible for identifying adverse system impacts on any affected systems and for determining what mitigation activities or upgrades may be required to accommodate a Small Generator Facility. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Applicant. The Applicant may be entitled to financial compensation from other utility Interconnection Customers or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Applicant, to the extent provided by a tariff or a separate Commission rule or order.

4.6 Billing

Montana-Dakota may require a deposit up to 50% of the cost estimate to be paid up front by the Applicant, for the studies, interconnection facilities, system upgrades, or other costs associated with the interconnection request. Progress billing, final billing, and payment schedules must be agreed to by the Parties prior to commencing work. The Billing Schedule should be attached to the agreement as "Attachment C" as needed.

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment

The Interconnection Agreement may be assigned by either Party upon fifteen (15) business days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

5.1.2 The Applicant shall have the right to assign the Agreement, without the consent of Montana-Dakota, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement. Attachment (H) can be used to document the assignment of a new owner to an existing facility.

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5.1.3 Any attempted assignment that violates this Article is void and ineffective.

5.2 Limitation of Liability and Consequential Damages

A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees caused by any act or omission in its performance of the provisions of an Interconnection Agreement. Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 Indemnity

5.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of the Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article, as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle, or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.4 Consequential Damages

With the exception of third party claims, neither Party shall be liable to the other Party, under any provision of the Agreement, for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to

the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 **Force Majeure**

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. If the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by Rule that the Rule does not permit the Parties to mutually waive.

5.6 **Default**

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement. Upon a default, the non-defaulting Party shall give written notice of such default to the defaulting Party. Except as provided in Article 5.6.2, the defaulting Party shall have sixty (60) calendar days from receipt of the default notice within which to cure such default.

5.6.2 If a default is not cured as provided for in this Article, or if a default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate the Agreement by written notice, and be relieved of any further obligation hereunder and, whether or not that Party terminates the Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternately, the non-

defaulting Party shall have the right to seek dispute resolution with the Commission in lieu of termination. The provisions of this Article will survive termination of the Agreement.

Article 6. **Insurance**

At all times during this Agreement, each Party shall obtain and maintain the following insurance:

General Liability Insurance with limits not less than $1,000,000. Limits may be met in combination of both primary and umbrella/excess policies. Upon signing the Agreement, each Party shall furnish to the other Party certificates of insurance as evidence showing that the insurance policy(s) to be carried in accordance with this provision have been obtained. All insurance to be carried pursuant to the above shall be endorsed to require 30 day written notice prior to effective date of any modification or cancellation of such insurance to the certificate holder, unless such cancellation is due to non-payment, then 10 day written notice is required.

Article 7. **Dispute Resolution**

Parties will adhere to the dispute resolution and complaint process in Rate 96.

Article 8. **Miscellaneous**

8.1 **Governing Law, Regulatory Authority, and Rules**

The validity, interpretation, and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Montana, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 **Amendment**

The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of Rate 96 and applicable Commission Orders and provisions of the laws of the State of Montana.

8.3 **No Third-Party Beneficiaries**

The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

8.4 **Waiver**

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by Rate 96.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 Entire Agreement

The Interconnection Agreement, including any supplementary form attachments that may be necessary, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under the Agreement.

8.6 Multiple Counterparts

The Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 No Partnership

The Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 Severability

If any provision or portion of the Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of the Agreement shall remain in full force and effect.

8.9 Subcontractors

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Nothing in the Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in the Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under the Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of the Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under the Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by the Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

Either Party will have the right to make a unilateral filing with the Commission to modify the Interconnection Agreement. This reservation of rights provision includes, but is not limited to, modifications with respect to any rates, terms, and conditions, charges, classification of service, tariff, or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. Notices

9.1 General

Unless otherwise provided in the Agreement, any written notice, demand, or request required or authorized in connection with the Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the persons specified below:

If to the Interconnection Applicant:

Attention: ______________________________

Address: ____

City: ____________________________ State: _____________ Zip: _______

Phone: ____________________ E-mail: ___________________

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If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

If to the Interconnection Applicant:

Attention: ______________________________

Address: ____

City: ____________________________ State: ____________ Zip: _______

Phone: ____________________ E-mail: ___________________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.3 Designated Operating Representative

The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of the Agreement. This person or persons will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

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If to the Interconnection Applicant:

Attention: ______________________

Address: ______________________________________

City: ____________________ State: __________ Zip: ______

Phone: ______________ E-mail: ______________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone: 1-800-638-3278

9.4 Changes to the Notice Information

Either Party may change this notice information by giving five business days written notice prior to the effective date of the change.

Article 10 Signatures

IN WITNESS WHEREOF, the Parties have caused the Agreement to be executed by their respective duly authorized representatives.

Montana-Dakota	Interconnection Applicant
Name: ______________	Name: ______________
Title: ______________	Title: ______________
Signature: ______________	Signature: ______________
Date: ______________	Date: ______________

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ADDENDUM "H" ASSIGNMENT ACKNOWLEDGEMENT AGREEMENT

APPLICATION SCOPE: For a Small Generator System that is incorporated into a building facility that has a current active Interconnection Agreement for Small Distribution Generator Facility approved by Montana Dakota Utilities Company. The Small Distribution Generator Facility Agreement will automatically transfer to the new owner upon the sale of the property and completion of this Assignment Acknowledgement Agreement by the New Owner-Operator. A copy of the original Interconnection Agreement will be sent to the New Owner-Operator for the purpose of this agreement.

Recitals:
Whereas, an existing Small Distribution Generator Facility is located at: ____________________ ______________________ (the "Property"), and operates pursuant to an Interconnection Agreement for Small Distribution Generator Facility dated the _____ day of _________, 20____ (the "Agreement") with Montana-Dakota Utilities Company, a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Whereas, a new owner has purchased the "Property" and desires to operate the Small Generator System under the same requirements set forth in the "Agreement".

Whereas, a copy of the original Interconnection Agreement is attached to this Acknowledgement Agreement.

AGREEMENT
Now, therefore, the New Owner-Operator is assigned and assumes all rights and obligations under the "Agreement".

Montana-Dakota - Acknowledgement	New Owner-Operator
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Signature: ______________________	Signature: ______________________
Date: ______________________	Date: ______________________

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I. PURPOSE:

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

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of Montana (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 Montana.

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 expressed 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 and water well pumps on the same premise as the living quarters, used for single family 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 nonresidential 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 salons, 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. CUSTOMER 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 for residential service shall not exceed one-sixth of the estimated annual billings. For non-residential

service, the amount of the deposit shall not exceed 25 percent of the estimated annual billings.

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

iii. Interest on deposits held shall be accrued at the rate of .5 percent per month. Interest shall be computed from the receipt of deposit to the time of refund or of termination. Interest shall be credited to the customer's account annually during the month of December.

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

3. LATE PAYMENT CHARGE:
Amounts billed for energy will be considered past due if not paid by the due date shown on the bill.
   i. For residential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the second subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment

arrangement, an amount equal to 1% of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

ii. For nonresidential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date.

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

4. RETURNED CHECK CHARGE:
A charge of $30.00 will be collected by the Company for each check not honored by customer’s financial institution for any reason.

5. MANUAL METER CHECK CHARGE:
A charge of $18.35 will be assessed monthly for 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. Customers 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 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 or other political subdivision for the privilege of conducting its utility operations therein.

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

7. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS:
For service requested by customer for cut-ins, cut-outs, and disconnection or reconnection of service after the Company's regular business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and material at retail prices.

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

   To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply unless service can be scheduled for a future workday.

8. RECONNECTION FEE FOR SEASONAL CUSTOMER:
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. All bills for services 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 Montana Public Service Commission.

   ii. The Company may collect a fee of $20.00 before restoring electric service which has been disconnected for nonpayment of service bills.

10. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILL:
   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. BILLING ERRORS:
Billing error means any bill issued by Company that is not designated as an estimate and that understates the amount owed by the customer. It also means the Company's failure to bill a customer, although there was energy consumption which would, under the Company's normal billing practices, be billed to the customer.
    i. When a billing error is discovered which is not the result of theft by the customer, the Company may submit a bill to the customer based

on the corrected information for a period not to exceed six months from the date the billing error is discovered.

ii. Billing errors on accounts of industrial customers are not limited to the six-month period applicable to all other customers.

14. INSTALLING TEMPORARY METERING OR SERVICE FOR ELECTRIC FACILITY:
A customer requesting temporary metering service will be charged on a time and material basis in accordance with Electric Service Rules and Regulations Rate 110.

15. SERVICES ON CUSTOMER PREMISES – ELECTRIC NONCHARGEABLE – UTILITY SERVICES:
    i. Fire Call
    ii. Investigate hazardous condition on customer premises
    iii. No lights or power investigation
    iv. Maintenance or repair of Company-owned equipment on the customer's premise –
        a. Meter
        b. Overhead service line
        c. Underground service line
    v. Checking voltage or loads
    vi. Locating radio, cb or television interference
    vii. High bill complaint
    viii. Cut-ins and cut-outs (regular work hours)

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

Reserved for future use

Reserved for future use

Reserved for future use

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC SERVICE
RULES and REGULATIONS

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Section 100 - General

101. 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 Commission 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.

102. 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.

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. Any customer may be required to make a deposit as required by the Company. 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.

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. The Company will make reasonable effort to contact the customer, but the Company reserves the right to interrupt service to conduct maintenance on metering equipment, including an exchange of the meter.

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 customer's premise. It is the obligation of the customer to consult with the Company regarding maximum available 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 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 hold 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 conduit 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.

<u>207. Overhead to Underground Primary Conversion</u>
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 results 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 (Only allowed by special request – see Section 302.3)
**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 Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in 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 may not be 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 Electrical 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 150feet, 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 actual 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 the 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. The customer will utilize meter sockets from a Company approved list of manufacturers and models as posted on the Company's website. 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. U.L. approved, ringless style.
2. 100 ampere minimum for overhead service installations.
3. 150 ampere minimum for underground service installations.
4. Stud connectors are required for all sockets rate 320 amps or greater.
5. For sockets rated below 320 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.

7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
8. 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. Customer must provide hub closing plate.
4. Automatic by-pass feature is not acceptable.

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. For 480 volt service, enclosures must be sized to include room to mount voltage transformers or a separate weatherproof enclosure may be provided by the customer to mount 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 non fused rated disconnect 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.

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 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.

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 place on the exterior of the meter base on a non-removal 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 the 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 Commission.

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.

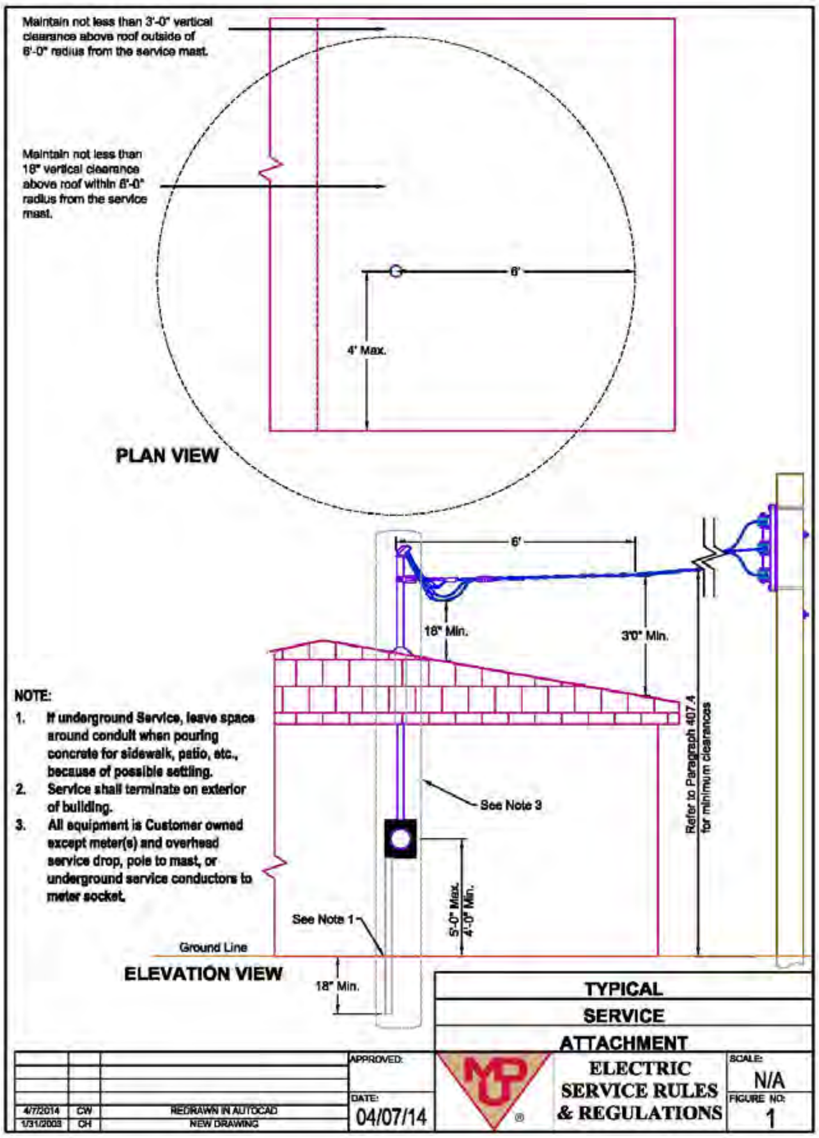
710. Computers and Electronic Equipment

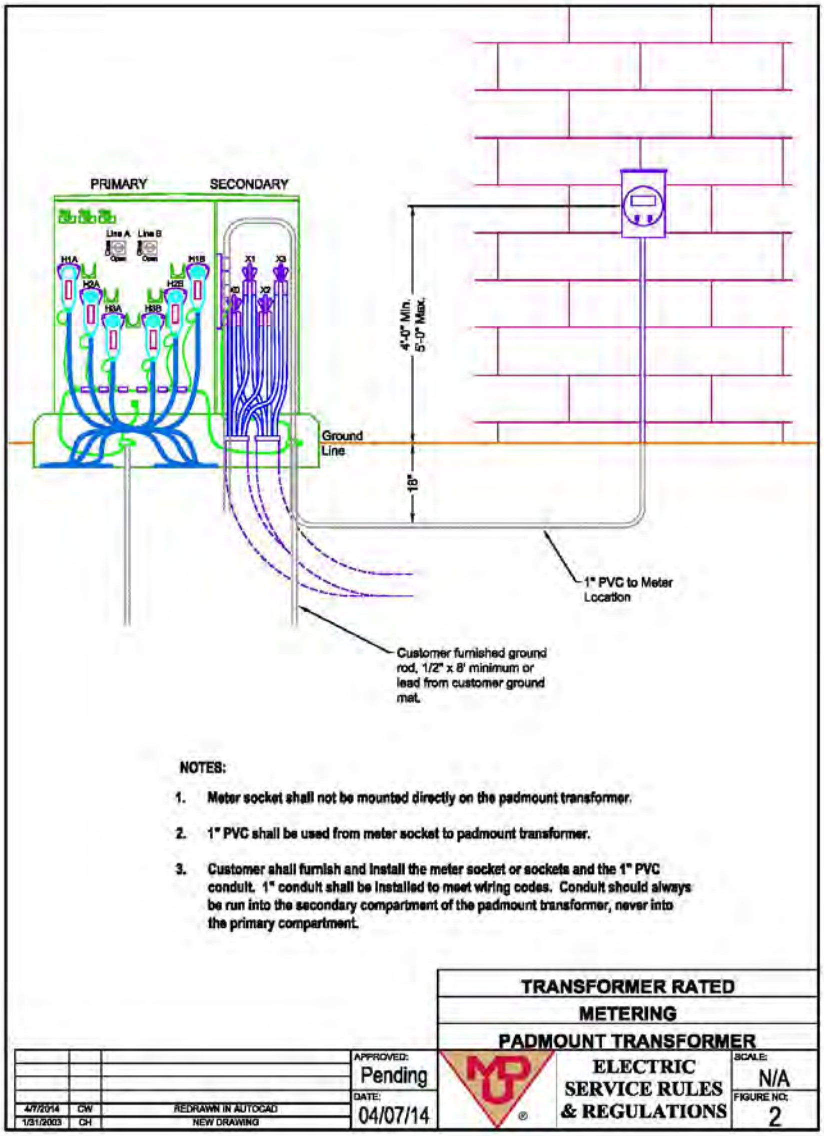
Computers and other sensitive electronic equipment which require high grade, uninterrupted power may, on occasion, experience problems when connected directly to the Company's distribution system. The customer should contact their equipment supplier or consultant to ascertain the need for lightning arresters,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

711. Carrier Equipment

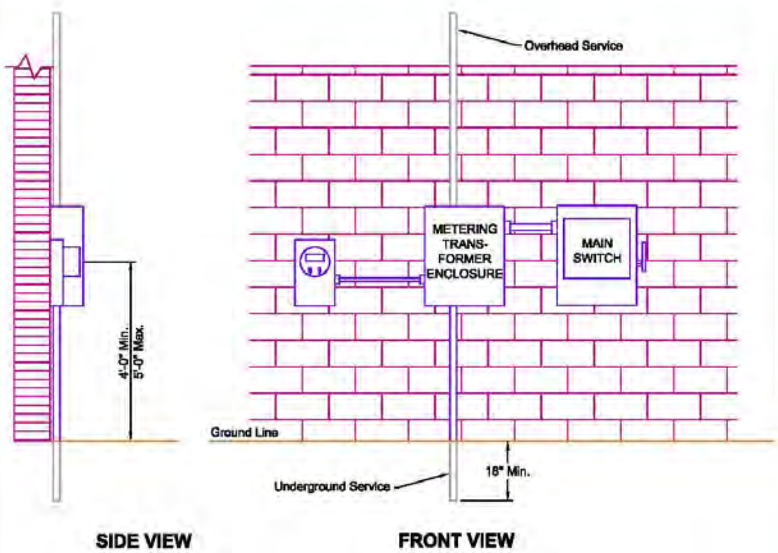
The customer shall not impose, or cause to be imposed, any electric signal of any frequency or magnitude upon the Company's distribution system.

ELECTRIC SERVICE RULES AND REGULATIONS Rate 110





PRIMARY
SECONDARY
H1A
H2A
H3A
H1B
H2B
H3B
Line A
Line B
X0
X1
X2
X3
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:

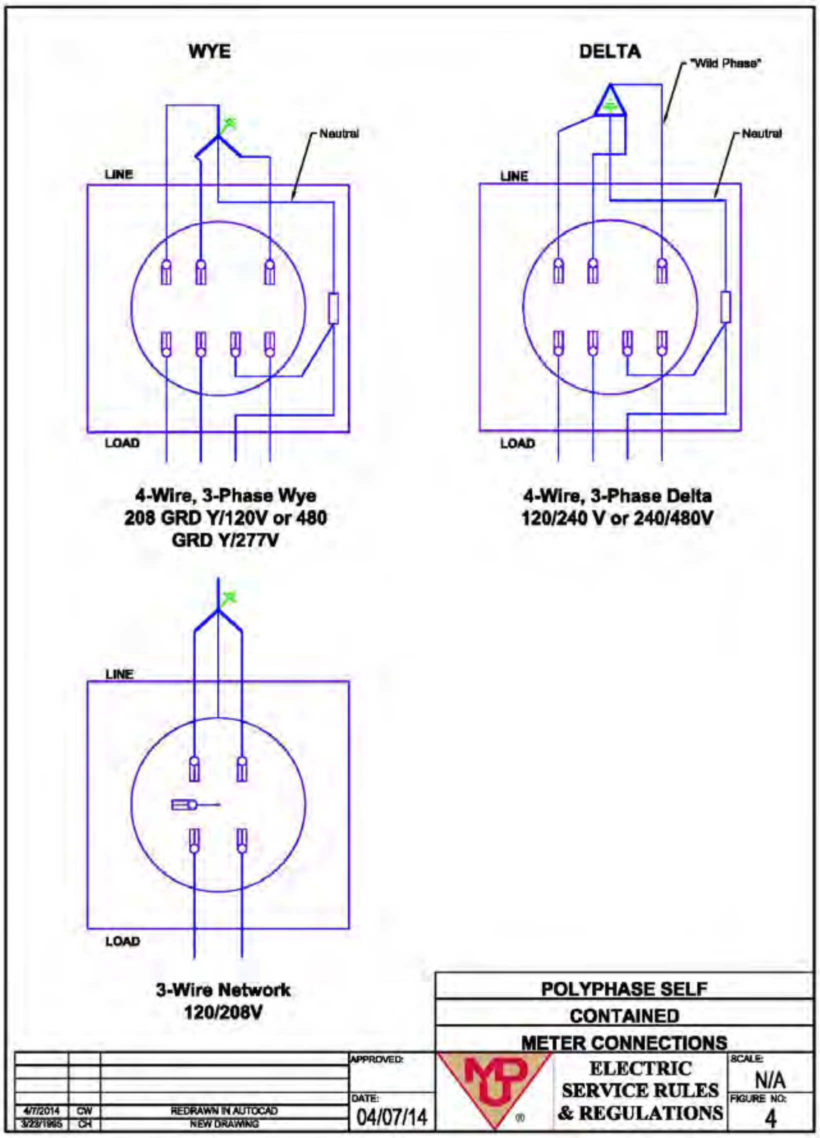
1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3.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

TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE

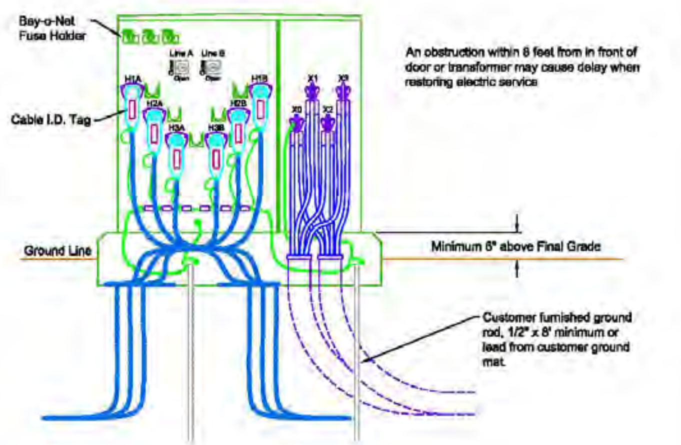
4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED:
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A
FIGURE NO: 3


WYE
DELTA
"Wild Phase"
Neutral
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
APPROVED:
DATE:
04/07/14
ELECTRIC
SERVICE RULES
& REGULATIONS
SCALE:
N/A
FIGURE NO:
4
4/7/2014 CW REDRAWN IN AUTOCAD
3/23/1995 CH NEW DRAWING

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



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

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

Issued: June 24, 2015 **By:** Tamie A. Aberle
Director - Regulatory Affairs

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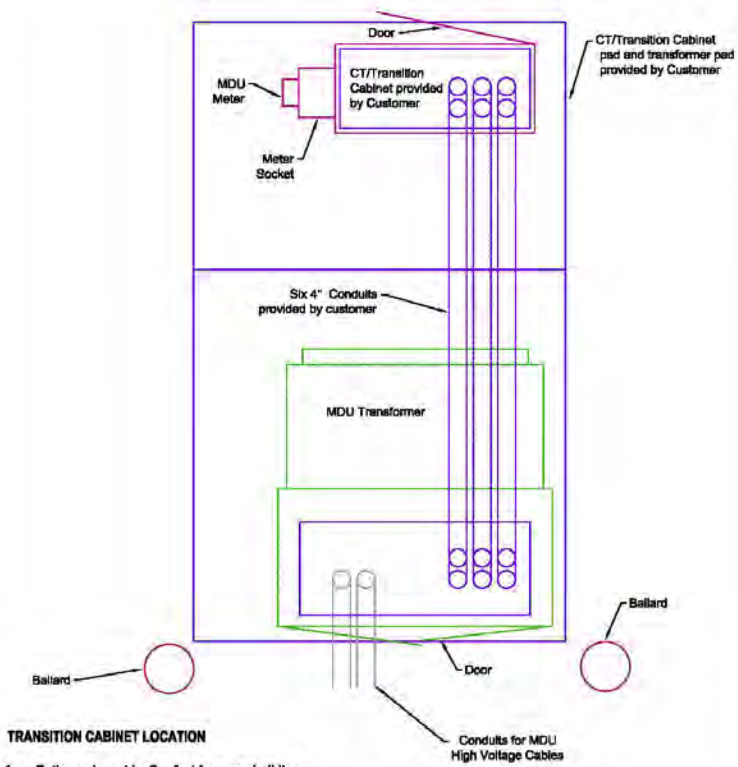
Docket No. D2015.6.51

Effective with service rendered on and after April 1, 2016

ELECTRIC SERVICE RULES AND REGULATIONS Rate 110



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

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 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) Residential Customers - If within a ten-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). A customer may receive a refund only if the customer paid for the initial extension or subsequent connection to the extension and at the time the refund is issued, the customer owns the residential structure to which the extension or subsequent connection to the extension was made. No refund shall be made by Company to residential customer(s) after a ten-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

2) Non-Residential Customers - 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). No refund shall be made by Company to non-residential customer(s) after a five-year period from which initial

service is established, nor shall refunds be made in excess of the amount contributed.

3) Developers of Subdivisions - Refunds 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. No refund shall be made by Company to a 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 Montana 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

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 $\pm$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 $\pm$ 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 meters in a given vintage class fail to meet the requirements of $\pm$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 $\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.

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 $\pm$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 meters in a given vintage class fail to meet the requirements of $\pm$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 $\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 two 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 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 two years rather than the entire vintage class.

Montana-Dakota Utilities Co.
Montana Electric Tariffs - Proposed

Appendix B

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

State of Montana
Electric Rate Schedule

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COMMUNITIES SERVED

Badlands Region

Antelope	*Glendive	Redstone
Bainville	Homestead	Reserve
Baker	Ismay	Rosebud
Brockton	Kinsey	Savage
Culbertson	Medicine Lake	Scobey
Fairview	*Miles City	Sidney
Fallon	Outlook	Terry
Flaxville	Plentywood	Whitetail
Forsyth	Plevna	Wibaux
Froid	Poplar	*Wolf Point

*Designates District 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:	$0.25 per day
Energy Charge:	
October – May	7.668¢ per Kwh
June – September	9.665¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. Low-Income Discount: Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered

based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP.

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

2. The foregoing schedule is subject to Rates 100-131 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 arranged so that all service can be measured through one meter.

RATE:

Basic Service Charge: $0.47 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	7.508¢ per Kwh
June – September	10.938¢ per Kwh

Off-Peak Energy: 6.844¢ per Kwh for all energy not covered by the On-Peak rating period.

Base Fuel and Purchased Power: 2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. 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 of returning to the regular Residential Electric Service rate.

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

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

3. The foregoing schedule is subject to Rates 100-131 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 of 50 Kilowatts or less 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:

Basic Service Charge:	$0.90 per day
Primary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$13.00 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$14.00 per Kw
Energy Charge:	
October – May	4.029¢ per Kwh
June – September	5.909¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ per Kwh
Secondary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$13.75 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$15.00 per Kw

Energy Charge:	
October – May	4.129¢ per Kwh
June – September	6.009¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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. Customer 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. The 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. 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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:

For irrigation power service.

RATE:

Basic Service Charge:	$1.00 per day
Demand Charge:	
October – May	$4.00 per Kw
June – September	$6.00 per Kw
Energy Charge:	3.006¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-131 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 of 50 Kilowatts or less 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:	$44.15 per month
Primary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$13.81 per Kw
June – September	$16.95 per Kw
On-Peak Energy:	
October – May	5.954¢ per Kwh
June – September	7.301¢ per Kwh
Off-Peak Energy:	3.681¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ per Kwh
Secondary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$14.08 per Kw
June – September	$17.39 per Kw

On-Peak Energy:	
October – May	5.918¢ per Kwh
June – September	7.392¢ per Kwh
Off-Peak Energy:	3.712¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. Demands will be determined to the nearest one-tenth kilowatt.

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. 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. The 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. 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 of returning to the regular Small General Electric Service rate.

4. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

LARGE GENERAL ELECTRIC SERVICE Rate 30

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand 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:	$255.00 per month
Demand Charge:	
October – May	$12.10 per Kw
June – September	$13.45 per Kw
Energy Charge:	2.855¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ per Kwh
Secondary Service:	
Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$12.30 per Kw
June – September	$13.65 per Kw
Energy Charge:	2.883¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 50 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. 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. The 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 100-131 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 LARGE GENERAL ELECTRIC SERVICE Rate 31

AVAILABILITY:

In all communities served for all types of demand metered general electric service exceeding 50 Kilowatts of billing demand 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:	$255.00 per month
On-Peak Demand Charge:	
October – May	$ 9.60 per Kw
June – September	$16.90 per Kw
On-Peak Energy:	
October – May	4.712¢ per Kwh
June – September	5.712¢ per Kwh
Off-Peak Energy:	2.712¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ per Kwh
Secondary Service:	
Basic Service Charge:	$100.00 per month
On-Peak Demand Charge:	
October – May	$10.50 per Kw
June – September	$17.50 per Kw

On-Peak Energy:	
October – May	4.712¢ per Kwh
June – September	5.712¢ per Kwh
Off-Peak Energy:	2.712¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. 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. 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 agrees to contract for service under the Optional Time-of-Day Large 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 Large General Electric Service rate or of returning to the regular Large General Electric Service rate.

3. The 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.

4. The foregoing schedule is subject to Rates 100-131 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:	$55.00 per month
Primary Service:	
Demand Charge:	
October – May	$ 3.00 per Kw
June – September	$12.70 per Kw
Energy Charge:	3.039¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$ 3.50 per Kw
June – September	$12.90 per Kw
Energy Charge:	3.039¢ per Kwh
Base Fuel and Purchased Power:	2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

CONTRACT SERVICE Rate 35

AVAILABILITY:

For the Denbury Onshore LLC accounts designated in the Electric Service Agreement dated June 28, 2017.

RATE:

Basic Service Charge:	$285.00 per month
Demand Charge:	
October – May	$10.25 per Kw
June – September	$11.75 per Kw
Energy Charge:	2.691¢ per Kwh
Base Fuel and Purchased Power:	2.785¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

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 50 Kw. Demands will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

Montana-Dakota reserves the right to require Denbury Onshore LLC 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 Denbury Onshore LLC 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:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by Montana-Dakota under the laws of the state.

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT:

The following sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment for Contact Service Rate 35. It specifies the procedure to be utilized to adjust the rates for electricity sold in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account as allocated to Contract Service Rate 35.

1. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

   Unless otherwise ordered by the Commission, the effective date of the Fuel and Power Cost Tracking Adjustment and amortization of the Unreflected Fuel Cost Account shall be service rendered on and after January 1 each year.

2. FUEL AND POWER COST TRACKING ADJUSTMENT:

   a. The Fuel and Power Cost Tracking Adjustment shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base

fuel cost shall be 2.785¢ per Kwh as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for Rate 35, and shall be the sum of the following estimated costs for the annual period the adjustment shall be in effect, as allocated to Montana and to Contract Service Rate 35, taking into account applicable line losses:
   1. The cost of fossil and other fuels and sand and reagents as recorded in Account Nos. 501, 502 and 547.
   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555.
   3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the year is the sum of 2(b) above divided by projected Contract Service Rate 35 sales volumes for the period the adjustment will be in effect.

d. The Annual Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 2(b) multiplied by ninety (90) percent.

3. UNREFLECTED FUEL COST ADJUSTMENT:
   Contract Service Rate 35 shall be subject to an Unreflected Fuel Cost Adjustment to be effective on January 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

4. UNREFLECTED FUEL COST ACCOUNT:
   a. Items to be included in the Unreflected Fuel Cost Account are:
      1. Amounts under recovered or over recovered for fuel and purchased power each month as calculated in accordance with Subsection 4(b).
      2. Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

   b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 4(a)(1) and (2) shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power.
      2. Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.
      3. The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in an Unreflected Fuel Cost Account for Contract Service Rate 35.
      4. Carrying charges or credits at a rate equal to the overall rate of return established in the most recent general rate case.

   c. Reduction of Amounts in the Unreflected Fuel Cost Account:
      1. The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 4) under Contract Service Rate 35. The Account shall be increased in the event the adjustment is a negative amount. The amount amortized shall be applied pro rata between the Unrecovered Fuel Cost Account and the interest balance.

5. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES: The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

6. TIME AND MANNER OF FILING:
   a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 6 identifying the amount of the adjustment.

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

7. EFFECTIVE ADJUSTMENT:

Base Fuel	2.785¢
Fuel and Power Cost Adjustment	________________
Total Adjustment per Kwh	

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:	$255.00 per month
Demand Charge:	
October – May	$8.60 per Kw
June – September	$9.95 per Kw
Energy Charge:	2.855¢ per Kwh
Base Fuel and Purchased Power:	2.714¢ 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.

ADJUSTMENT CLAUSES:

Bills are subject to the following adjustments as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 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. Company will notify 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 used 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.

INTERRUPTIBLE LARGE POWER DEMAND RESPONSE Rate 38

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. 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 100-131 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 public 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:

Energy Charge:	7.295¢ per Kwh computed according to the total rated capacity of the lamps in use.
Base Fuel and Purchased Power:	2.900¢ per Kwh

FACILITIES CHARGE per unit per month:

Applicable to lighting facilities owned, installed, and maintained by the Company.

LED, Overhead Conductor, Distribution Pole	$4.00
LED, Overhead Conductor, Street Light Pole	$7.60
LED, Underground Conductor, Distribution Pole	$5.10
LED, Underground Conductors, Street Light Pole	$8.70
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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 municipality for the cost of repair and replacement.

2. 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.

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

4. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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:

Basic Service Charge: $40.00 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	$4.50 per Kw
June – September	$6.50 per Kw

Energy Charge: 3.523¢ per Kwh

Base Fuel and Purchased Power: 2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

MUNICIPAL PUMPING SERVICE Rate 48

- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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:

The foregoing schedule is subject to Rates 100-131 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, Christmas lights and yard light units in all communities served. Lighting equipment may be Company-owned or customer-owned.

RATE:

Energy Charge:	12.948¢ per Kwh computed according to the total rated capacity of the units in use.
Base Fuel and Purchased Power:	2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

OUTDOOR LIGHTING SERVICE Rate 52

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 the 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. 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 customers. Christmas lighting will be billed for the months in service.

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. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

ELECTRIC LINE MOVING COST SCHEDULE Rate 53

APPLICABILITY:

This rate schedule sets forth the charges to be applied to recover the costs associated with the expense of moving poles or raising or cutting wires or cables to accommodate the relocation of a structure, as required by Montana Code Annoted (MCA) Section 69-4-602 and 69-4-603.

CHARGES:

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a house, building, derrick, other structure, or prefabricated structure that is intended to be moved from the place of fabrication, storage facility, or dealer's lot, determined in accordance with the rates set forth below must be paid by the mover.

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a structure, determined in accordance with the rates set forth below must be shared equally by the mover and the owner of the wires, cables, or poles if the structure is owned by a person for occupancy or use by that person.

RATE:

Refer to Cost Schedule for current rate information

GENERAL TERMS AND CONDITIONS:

1. Prepayment – The mover shall make a prepayment of a portion of the estimated total cost in advance of the move as follows:
    a. If the structure is moved through or out of the Company's service territory, 100% of the mover's share.
    b. If the structure is delivered to a place within the Company's service territory, 50% of the mover's share.
    c. The Company may waive the prepayment requirement or accept a bond or other financial instrument in lieu of payment.

ELECTRIC LINE MOVING COST SCHEDULE Rate 53

   d. The mover shall pay the mover's share of all actual costs in excess of any prepayment within 30 days of the move.
   e. If the prepayment made exceeds the mover's share of actual costs the Company shall refund the difference to the mover within 30 days of the move.

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

ELECTRIC UNIVERSAL SYSTEM BENEFITS CHARGE Rate 55

APPLICABILITY:

In all communities served for all retail electric service in order to recover the costs associated with Universal System Benefit Programs required by the Electric Utility Industry Restructuring and Customer Choice Act, Montana Code Ann. §§69-8-101.

RATE:

Large Customer Accounts(Defined Below):	.0900¢ per Kwh for all energy used.
All other accounts:	.1566¢ per Kwh for all energy used.

GENERAL TERMS AND CONDITIONS:

1. Large Customer Accounts are defined as any customer with monthly billing demands of 1,000 Kw or higher, determined by dividing the customer's previous calendar year's total billing demand by 12.

   a. Large Customer Accounts shall be charged an annual Universal System Benefits Charge(USBC) assessment equal to the lesser of $500,000 or the product of .09¢ per Kwh for all energy used.

   b. Large Customer Accounts shall receive a credit toward their annual USBC assessment for internal expenditures and activities that qualify as Universal System Benefit programs as determined by the Montana Department of Revenue.

   c. Large Customer Accounts with qualifying credits that exceed the customers annual USBC assessment shall be carried forward and credited to customer's future USBC assessments until the total amount of the qualifying credits have been credited to the customer's account.

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

ELECTRIC TAX TRACKING ADJUSTMENT Rate 56

1. Applicability:

This rate schedule sets forth the procedure to be used in calculating the Tax Tracking Adjustment in order to reflect: (a) changes in Montana-Dakota's Montana state and local taxes and fees, and (b) a true-up of taxes recovered to actual taxes paid. The tax adjustment shall be shown as a separate item on the bill.

2. Effective Date:

The Tax Tracking Adjustment shall be adjusted annually and the effective date of the Tax Tracking Adjustment shall be service rendered on and after January 1 each year.

3. Tax Tracking Adjustment:

a. The Tax Tracking Adjustment shall reflect changes in Montana-Dakota's Montana state and local taxes and fees as compared to the base levels approved in its most recent general rate case. The difference to be included in the Tax Tracking Adjustment shall be net of income taxes.

b. Base Tax – A base tax amount shall be established and updated in general rate cases for each rate schedule:

(1) The ratio of authorized Montana state and local taxes and fees, excluding tribal taxes, to the non-fuel revenues shall be determined.

(2) The ratio is applied to the total basic service charge, energy charge, and demand charge revenues for each rate schedule to derive the base tax amount for each rate schedule.

c. Rates excluding taxes

(1) The authorized non-fuel revenue excluding base taxes (defined as base margin) is established by applying one minus the ratio derived in 3.b.(1) to the authorized non-fuel revenues by rate schedule.

(2) The percentage of base taxes to base margin is derived to establish the baseline tax recovery amounts included within the basic service charge,

energy charge and demand charge by applying that percentage to each rate component of each rate schedule.

d. The Tax Tracking Adjustment shall have two components and be computed as follows:

(1) Rate Year Estimate- To recover changes in estimated tax expenses from the base tax level for the year in which the rates will apply (the “Rate Year”), actual tax expense for the prior year shall be used as a proxy for Rate Year taxes and compared to the tax expense projected to be recovered in the Rate Year. That difference (whether positive or negative), adjusted for income taxes, is the Rate Year estimate component.

(2) Annual True-Up- To true-up each year’s tax expense recovered to the actual tax expense for that year, the actual tax expense for the year prior to the Rate Year is compared to the tax expense recovered in the same year. That difference (whether positive or negative), adjusted for income taxes, is the Annual True-Up component.

(3) The sum of amounts (positive or negative) in 3.d.(1) and 3.d.(2) above is divided by the base margin to derive the percent increase (decrease) in taxes.

(4) The base tax percentage determined in 3.c.(2) and the tax adjustment percentage determined in 3.d.(3) are added to calculate the total percent of taxes.

(5) The total percent of taxes is applied to the base margin, comprised of the basic service charge, energy charge, and demand charge billed to each customer, and shown separately on the customer bill.

ELECTRIC TAX TRACKING ADJUSTMENT Rate 56

4. Time and Manner of Filing:
A filing shall be made on or before November 30 of each year to modify the Tax Tracker Adjustment for the subsequent year. That filing shall be accompanied by the detailed computations which clearly show the derivation of the relevant amounts.

5. Tax Tracking Adjustment:

Base	11.8751%
Adjustment	0.0000%
Total tax	11.8751%

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

1. APPLICABILITY:
This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 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 tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:
Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs by month by source, with annual totals and;

b. Generation and purchases (Mwh) by month by supply source, with annual totals.

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.714¢ per Kwh for primary service and 2.900¢ per Kwh for secondary service as established in the most recent general rate case.

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 Montana and to the primary and secondary customer classes:

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

   2. The cost of electric transmission delivery services linked to the utility's load serving obligation and associated with participation in regional transmission organizations as recorded in Account Nos. 560, 561, 565 and 928 offset by corresponding revenues received from regional transmission organizations as recorded in Account No. 456.

   3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 4(c) multiplied by ninety (90) percent.

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

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

(1) Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power as specified in Subsection 4.

(2) Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.

(3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in the Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

(1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES:
The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

8. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

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

9. FUEL AND POWER COST ADJUSTMENT:

	Primary	Secondary
Base Fuel	2.714¢	2.900¢
Fuel and Power Cost Adjustment		
Total FPPA per Kwh		

AVAILABILITY:

Available to any customer with a small generator facility whose capacity does not exceed 50 Kw that is located on the customer's premises and is intended primarily to offset part or all of the customer's own electrical requirements. The small generating facility, hereinafter referred to as eligible customer generator, must be interconnected and operated in parallel with the Company's existing distribution facilities.

APPLICABILITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator that exceeds the customer's own use or is sold to Montana-Dakota.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Demand Charge: The Demand Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill. The balance of the energy generated shall appear as a credit on the customer's account until the customer's consumption offsets the credit or the end of the designated 12-month billing period, which ever occurs first. At the end of the 12-month period any unused Kwh credit

accumulated during the previous 12-months will be granted to the Company with no compensation to the customer. The customer shall designate the start date of the 12-month billing period as January 1, April 1, July 1 or October 1.

GENERAL TERMS AND CONDITIONS:

1. INTERCONNECTION AGREEMENT:
   Prior to connecting a renewable energy system to operate in parallel with the utility, the eligible customer-generator must initiate and enter into an Interconnection Agreement with the Company in accordance with Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96.

2. INTERCONNECTION AND OPERATION:
   a. Upon completion of a signed interconnection agreement and the initiation of service, the customer shall operate its Small Generator Facility in parallel with Montana-Dakota's system and in accordance with the terms of the Interconnection Agreement, Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff and the Administrative Rules of Montana 38.5.84.
   b. There should only be one net metering system installed per each metered service located on the customer's premises. The net metering system must have an aggregate nameplate capacity per premise that does not exceed 50 Kw and be fueled by solar, wind, or hydropower.
   c. Neither customers, customer accounts or services, nor meters may be aggregated for purposes of net metering.

3. METERING:
   Montana-Dakota will provide a standard meter capable of registering the flow of electricity in two directions. Any additional costs necessary for the interconnection are the responsibility of the customer in accordance with

Rate 96 ¶ VIII.5 and as outlined in the Small Generator Facility Distribution Interconnection Agreement.

4. INTERRUPTION OF DELIVERIES:
   The Company may require the customer to interrupt or reduce deliveries of available energy when Company determines (a) such interruption is necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any Company-owned equipment or part of the Company's system, or (b) that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with any electrical code or standard. Whenever possible, Company will give the customer notice of the possibility that interruption or reduction of deliveries may be required.

5. TEMPORARY DISCONNECTION OF FACILITY:
   If at any time the Company determines that either (a) the customer's eligible generator, or its operation, may endanger Company personnel, or (b) the continued operation of the generator may endanger the integrity of the Company's electric system, the Company shall have the right to disconnect the generator from the Company's system. The Company will give the customer notice of such occurrence as soon as practical. The customer's eligible generator will remain disconnected until such time as the Company determines that all condition(s) are such that it is safe to reconnect.

   The Company is not obligated to pay for energy that would otherwise have been delivered to its system absent the occurrences described in this section.

6. The foregoing schedule is subject to Rates 101 through 131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

POWER PURCHASE TIME DIFFERENTIATED Rate 93

AVAILABILITY:

To any qualifying cogeneration and small power production facility (QF), as defined under the Administrative Rules of the Montana Public Service Commission, for the purpose of generating electric energy in parallel with the Company's system, including ARM 38.5.1909 and any amendments or alternations to the rule. This schedule is applicable to a QF with a nameplate capacity of 3 MW or less who enters into a Power Purchase Agreement (Agreement) with the Company for a term not to exceed 15 years.

RATE:

Metering charge for single phase service	$6.50 per month
Metering charge for three phase service	$10.45 per month

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. Time Differentiated Energy Purchase Rate

	ON-PEAK	OFF-PEAK
2021	2.194¢ per Kwh	2.267¢ per Kwh
2022	2.072¢ per Kwh	2.139¢ per Kwh
2023	2.134¢ per Kwh	2.203¢ per Kwh
2024	2.198¢ per Kwh	2.269¢ per Kwh
2025	2.264¢ per Kwh	2.337¢ per Kwh
2026	2.332¢ per Kwh	2.407¢ per Kwh
2027	2.402¢ per Kwh	2.479¢ per Kwh
2028	2.474¢ per Kwh	2.553¢ per Kwh
2029	2.548¢ per Kwh	2.630¢ per Kwh
2030	2.624¢ per Kwh	2.709¢ per Kwh
2031	2.703¢ per Kwh	2.790¢ per Kwh
2032	2.784¢ per Kwh	2.874¢ per Kwh
2033	2.868¢ per Kwh	2.960¢ per Kwh
2034	2.954¢ per Kwh	3.049¢ per Kwh
2035	3.043¢ per Kwh	3.140¢ per Kwh
2036	3.134¢ per Kwh	3.234¢ per Kwh

Rating 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 Company's system operating characteristics.

2. Actual time differentiated system lambda determined for the month prior to the month in which energy is delivered by a QF.

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- Resource Adequacy of the MISO tariff.

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

Capacity payments will be paid in the subsequent billing period.

Monthly capacity payments 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 $10.004 per Kw applicable for the remainder of the term of the contract.

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 or large general service, etc.) that is currently on file with the Commission.

GENERAL TERMS AND CONDITIONS:

1. All purchases and sales of electric power between the Company and a QF of 3 MWs or less shall be accomplished according to the terms of a written contract and in accordance with the terms of this tariff.

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

3. The QF must apply for and enter into an Interconnection Agreement with the Company or the Transmission Service Provider prior to actual installation of equipment. A QF is responsible for all system Interconnection Facilities related costs and Network Upgrade costs. The QF shall be refunded its Network Upgrade related costs according to the terms and conditions of the applicable MISO tariff.

   Interconnection Facilities means the Company's or the Transmission Service Provider's Interconnection Facilities and the QF Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the QF and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   Network Upgrades are additions, modifications and upgrades to the Company's, Transmission Service Provider's or other affected parties' transmission system required at or beyond the point at which the QF interconnects with the transmission system to accommodate the interconnection with the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   The rates and terms and conditions set forth herein are subject to the provisions of the "Interconnection Cost Amortization Option" set forth in Rate 95.

POWER PURCHASE TIME DIFFERENTIATED Rate 93

4. 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.

5. The QF 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.

6. The QF has the option of contracting for either the "Standard Payment Option" or "Net Billing Option Rate 94" for purposes of computing payments as stipulated in the written contract.

7. Sales by the QF to the Company do not include the transfer of the RECs associated with the energy produced. The RECs shall remain with the QF to utilize at their discretion.

8. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

NET BILLING OPTION Rate 94

In addition to the parties' contract agreement, Company and Seller agree to the following net billing option:

1. Description: Under this option all purchases of energy from Seller by Company shall be considered on a net consumption basis, offsetting Company's purchases from Seller against its sales to Seller. If Company's sales to Seller are greater than its purchases from Seller in a billing period, Seller's net consumption shall be billed at the applicable retail rate and no further Avoided Cost Payments shall be made to Seller. If Company's purchases from Seller exceed its sales to Seller during a billing period, then the net purchases shall be purchased from Seller by Company pursuant to the applicable Avoided Cost Payments schedule. All purchases of capacity from Seller by Company will be considered on a net basis, offsetting Company's capacity purchases from Seller against its capacity sales to Seller on an hourly basis. Capacity payments will only be made if Company's energy purchases from Seller exceed its energy sales to Seller during a billing period.

2. Metering:
   (a) Energy: Company, at its expense, will install separate meters equipped with detents to measure its purchases from and sales to Seller.

   (b) Capacity: Company will make no Avoided Cost Payments for Capacity nor apply any offsets to its Demand charges for Capacity supplied by Seller unless such Capacity purchases by Company from Seller are separately metered. Such meters will be installed at Seller's expense.

3. Interconnection: Nothing herein shall relieve Seller from providing all necessary equipment for interconnection specified in the parties' contract.

4. Termination: If Seller fails to make any payments due to Company and Company is unable to recoup such overdue payments from Seller as an offset against Avoided Cost Payments for three consecutive months, the Net Billing Option shall automatically terminate and Company shall be entitled to its remedies under Montana Public Service Commission Rules (ARM 38.5.1401 et seq.).

5. Election: The election of the Net Billing Option is the sole prerogative of Seller. This option is merely an addendum to the parties' underlying standard contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' standard contract, the specific provision in this option controls.

INTERCONNECTION COST AMORTIZATION OPTION Rate 95

In addition to the parties' contract agreement, Company and Seller agree to the following interconnection cost amortization option:

1. Description: Under this option, Seller's obligation to reimburse Company for its cost of interconnection with Seller shall be made in monthly installments, such installments to include a finance charge as provided herein.

2. Finance Charge: Company's Cost of Interconnection shall be deemed to be the principal amount due and owing Company by Seller. The term of the loan shall be deemed to be the class life used by the Company for depreciating the special facilities required for interconnection or the length of the parties' contract, whichever is shorter. Seller shall repay the principal to Company in equal monthly installments over the term of the loan. Seller shall pay to Company each month interest on the unpaid balance computed, on an annual basis, to be equal to the incremental cost of capital to Company as of the date of the execution of this agreement. The incremental cost of capital to Company shall consist of the last cost of equity capital authorized by the Montana Public Service Commission, the current cost of new debt issues rate similarly to the bonds issued by Company, and the last cost of preferred stock experienced by Company.

3. Mortgage Requirement: Seller shall execute a first mortgage upon the Seller's property in favor of Company securing to Company full payment of all amounts due Company under this financing arrangement. In the event of a prior mortgage commitment, Seller shall secure for Company an adequate subordination agreement placing the mortgage required herein in a first position.

INTERCONNECTION COST AMORTIZATION OPTION Rate 95

4. Nonpayment by Seller: In the event of nonpayment by Seller of any monthly installment due Company under this financing arrangement, Company may:
   (a) Offset the late payment against any amount due Seller from Company and thereafter deduct from each month's payments due Seller from Company an amount sufficient to cover the next month's installment of principal and interest due Company under this financing arrangement.

   (b) In the event the nonpayment exists for three consecutive months, declare the entire principal amount due and owing, together with any interest accrued thereon, declare the Seller in default, and exercise its rights under the parties' mortgage, and cease interconnection with Seller as a qualifying facility.

5. Necessary Documents: Seller shall execute all documents deemed necessary by Company to perfect a secured load transaction including, but not limited to, a note, mortgage, and Truth in Lending disclosure statement. Upon satisfaction of all of Seller's obligations under this financing arrangement, Company shall promptly release its mortgage interest in the property of the qualifying facility.

6. Election: The election of the Interconnection Cost Amortization Option shall be the sole prerogative of Seller. Seller's election shall be manifested by the parties' separate execution of this option. This option is merely an addendum to the parties' contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' contract, the specific provision in this option controls.

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I. PURPOSE and APPLICABILITY:

This tariff is intended to provide the interconnection rules and procedures for any distribution customer of Montana-Dakota Utilities Co. (Montana-Dakota) located in the State of Montana proposing to install and interconnect a small generator facility to Montana-Dakota Electric Distribution System (EDS). The Small Generator Facility's nameplate capacity must be less than or equal to 10 MW and satisfy the following criteria:

1. The proposed small generator facility must be located on a utility customer's premise.
2. The customer installing the small generator facility must be in good standing with the Company.
3. The proposed small generator facility's point of interconnection may not be on a transmission line.
4. The power produced from the small generation facility must be contained on the Company's EDS and not flow onto Montana-Dakota's Electric Transmission System (ETS).
5. The power produced by the small generation facility must be intended to be utilized by the customer or sold to Montana-Dakota.

Generators that are proposed and designed for interconnection to the Company's ETS (interconnections to voltages above 25KV) or to deliver power to the Company's ETS are not covered under this scope of this tariff.

II. DEFINITIONS:

The following terms used in this tariff have the following meanings, except where the context clearly indicates otherwise:

APPLICANT - A person or entity that has filed an application to interconnect a customer generator to Montana-Dakota's Electric Distribution System (EDS). An applicant may include a third party who owns and operates a small generator facility under agreement with a customer or leases a small generator facility to a

customer.

COMMISSION - Public Service Commission of the State of Montana

CUSTOMER - Any entity connected to the utility system for the purpose of receiving electric power from the Company

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

CUSTOMER-GENERATOR - A customer that generates electricity, typically on the customer's side of the meter.

ELECTRIC DISTRIBUTION SYSTEM (EDS) –

1. The infrastructure constructed, maintained, and under the jurisdiction of Montana Dakota Utilities Co.
2. Electric Distribution System has the same meaning as the term Area EPS, as defined in 3.1.6.1 of the IEEE Standard 1547-2003.

ELECTRIC DISTRIBUTION COMPANY (EDC) – An electric utility that distributes electricity to end users within the State of Montana and is subject to regulation by the Commission.

ELECTRIC TRANSMISSION SYSTEM (ETS) – Montana-Dakota's Electric System that operates at voltages above 25KV are defined as transmission for the purpose of this rate schedule.

EXPORT - Power flows past the point of interconnection onto the EDS.

GOOD STANDING - A customer's account is not in arrears.

IEEE - Institute of Electrical and Electronics Engineers.

IEEE STANDARDS - The standards published by the Institute of Electrical and Electronics Engineers.

INTERCONNECT - To connect a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION - The result of connecting a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION CUSTOMER - An applicant that has entered into an interconnection agreement with Montana-Dakota to interconnect a small generator facility and has interconnected that small generator facility to Montana-Dakota's EDS.

INTERCONNECTION EQUIPMENT – A group of components or an integrated system provided by the interconnection customer to connect a small generator facility to Montana-Dakota's EDS, including all interface equipment such as switchgear, protective devices, inverters, or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

INTERCONNECTION FACILITIES – The facilities and equipment required by Montana-Dakota to accommodate the interconnection of a small generator facility to Montana-Dakota's EDS and used exclusively to interconnect a specific small generator facility. Interconnection facilities do not include system upgrades that may benefit Montana-Dakota, other customers, other interconnection customers, or an owner of an affected system.

LINE SECTION - The portion of a radial distribution circuit to which an applicant seeks to interconnect and is bounded by sectionalizing devices or is located at the end of a distribution line.

NAMEPLATE CAPACITY - The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer and is usually indicated on a nameplate physically attached to the power production equipment.

NATIONALLY RECOGNIZED TESTING LABORATORY (NRTL) - A testing laboratory that is recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards.

NON-CONTINOUS PARALLEL GENERATOR – A generator that is designed to parallel the EDS for a short time period during a transfer of load for periods typically less than two minutes. This includes High Speed Transfer Switch Interconnections, Closed Transfer Systems, or Hot Transfer Standby Generator designs. The application process for this type of request will require the same process as a Continuous Parallel Generator. Some interconnection requirements may be relaxed, and an Interconnection Agreement may not be required, as determined on a case by case basis.

RADIAL DISTRIBUTION CIRCUIT - A circuit configuration in which independent feeders branch out radially from a common source of supply. In a radial distribution system, power flows in one direction from the company substation feeder to the load.

SMALL GENERATOR FACILITY - An energy resource(s) for the production and/or storage of electricity on the utility customer's premises that have an aggregate nameplate capacity that is less than or equal to 10 MW.

WITNESS TEST – A test performed jointly with Montana-Dakota to verify basic functionality of the small generator equipment and that the installation operates within acceptable limits of operation and does not interfere with the safety and operation of the EDS.

III. REQUEST FOR INTERCONNECTION:

1. INTERCONNECTION REQUEST:
   An applicant wanting to interconnect a small generator facility to the Company's EDS shall submit a Small Generator Facility Distribution Interconnection Application Form to Montana-Dakota.

   The applicant must determine, prior to the submission of an application, the Interconnection Level the project will be submitted under. A preliminary consultation with Montana-Dakota personnel is recommended to help simplify the process prior to submitting an application form.

2. QUEUE POSITION:
   Upon the receipt of an interconnection application request, Montana-Dakota shall assign a queue number in order to establish precedent with other existing and future interconnection requests on the same distribution circuit. The queue position of the interconnection request shall be used to determine the potential adverse system impacts of the small generator facility based on the relevant screening due to the nature of where a project is listed within the queue on a particular circuit. This will be communicated on the request acknowledgement form sent back to the applicant after the receipt of an application.

3. AGGREGATION OF MULTIPLE GENERATORS –
   a. An interconnection request for a small generator facility that includes multiple energy production devices at the common site where the applicant seeks a single point of interconnection shall be evaluated on the basis of the total aggregate nameplate capacity of the multiple devices.

   b. An interconnection request for an increase in the capacity for an existing small generator facility shall be evaluated using the new total aggregate capacity of the generators at the interconnection site.

4. FEE SCHEDULE:
   Interconnection applications must include a non-refundable application fee for Level 1 and 2 interconnection requests or a refundable deposit for Level 3 and 4 interconnection requests. The amount of the fee is dependent on the review level procedures of the interconnection request. All fees or deposits for processing such request must be paid prior to acceptance of the interconnection request by the Company.

Level 1 Application Fee -	$ 50.00
Level 2 Application Fee -	$200.00
Level 3 Application Deposit -	$500.00
Level 4 Application Deposit -	$500.00

   Interconnection Review Levels 1, 2, 3, and 4 are defined in Section III.7 of this tariff.

5. MODIFICATION OF APPROVED APPLICATION:
   When an interconnection request is deemed complete between Montana-Dakota and an applicant, any modification or change to the completed interconnection not agreed to by Montana-Dakota in writing shall require the submission of a new interconnection application request.

6. CERTIFIED EQUIPMENT:
   Interconnection application requests may be eligible for review procedures as outlined below in this tariff if the small generator facility uses certified interconnection equipment.
   a. Interconnection equipment shall be deemed certified upon the establishment of all the following:
      i. The interconnection equipment has been labeled and is publicly listed by a National Recognized Testing Lab (NRTL) at the time of the application.
      ii. The equipment must have certification testing results available from the manufacturer or NRTL upon request of the Company.

iii. The applicant must verify and provide information that the certified interconnection equipment is compatible with the generator and that the planned use of the certified interconnection equipment falls within the labeled and certified use and limits listed by the manufacturer.

iv. The interconnection equipment must be evaluated by a NRTL in accordance with the following codes:
   1. IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems using the testing protocol IEEE 1547.1-2005 Standard testing procedures to establish conformity.
   2. UL 1741 Standard Inverters, Converters, and Controllers for Use in Independent Power Systems.

7. INTERCONNECTION REVIEW LEVELS:
   Interconnection application requests shall be reviewed using one of the following four procedures, based on size, complexity, and characteristics of the project:

   a. Level 1 – Small Generator Facility – Certified Inverter Connected up to 50 KW: applicable to proposed customer generation interconnections where the generator size is 50 KW or less and the generated power is to be interconnected to the radial EDS utilizing Certified Inverter Equipment.

   b. Level 2 – Small Generator Facility – Certified Equipment Connected up to 2 MW: applicable to proposed customer generation interconnections where the generator size is 2 MW or less and the generated power is to be connected to the radial EDS utilizing Certified Inverter Equipment.

      Interconnection requests previously submitted under Level 1 but not approved under Level 1 may be reviewed as a Level 2 request under a new interconnection request for consideration.

   c. Level 3 – Small Generator Facility – No Power Export – Up to 10 MW: applicable to proposed customer generation interconnections where the size

of the equipment is less than 10 MW and the generated power is planned for customer load with no power exported to the Company's EDS.

Interconnection requests previously submitted under Level 2 but not approved under Level 2 may be reviewed as a Level 3 request under a new interconnection request for consideration.

d. Level 4 – Small Generator Facility – Up to 10 MW: applicable to proposed customer generation interconnections where the size of the generation is less than 10 MW and the interconnection request does not meet the criteria for review under Levels 1, 2, or 3, or was not approved under Interconnection requests previously submitted for review under Levels 1, 2, or 3.

IV. LEVEL 1 REVIEW PROCEDURES:

An application interconnection request submitted under Level 1 shall be subject to the following review procedures:

1. The Level 1 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and shall indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:

a. Verify that the Interconnection Inverter Equipment Certification is valid and proper.
b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
   i. 15% of the peak load on the line section
   ii. The annual minimum load for the line section
c. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
d. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
e. The proposed small generator facility shall not exceed the capacity of the existing electrical service.
f. The Level 1 application cannot require any construction modifications to the Company's EDS

4. The Company shall, within 15 business days of an interconnection application being deemed complete, provide verification that the small generator facility equipment can be interconnected safely and reliably using Level 1 screens.

5. Within 5 business days of an approved Level 1 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   b. The Witness Test has been performed and successfully completed.

7. If the Level 1 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 1 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 2, Level 3, or Level 4 review. The line section queue position assigned to the Level 1 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

V. LEVEL 2 REVIEW PROCEDURES:

An application interconnection request submitted under Level 2 shall be subject to the following review procedures:

1. The Level 2 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:
   a. Verify that the Interconnection Inverter/Equipment Certification is valid and proper.
   b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
      i. 15% of the peak load on the line section
      ii. The annual minimum load for the line section

c. The proposed small generator facility, in total with other generation on the distribution circuit, must not contribute more than 10% to the maximum fault current at the point on the primary line nearest the point of interconnection.
d. The proposed small generator facility, in total with other generation on the distribution circuit, must not cause any distribution protective devices and equipment, or other customer equipment on the EDS to be exposed to fault currents exceeding 90% of the short circuit interrupting capability including X/R effects.
e. The proposed small generator facility, in total with other generation interconnected to the primary distribution side of a substation transformer feeding the circuit, may not exceed 10 MW in an area where there are known transient stability limitations to generating units located in the general electrical vicinity.
f. When a three phase three wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected phase-to-phase.
g. When a three phase four wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected line-to-neutral and shall be effectively grounded.
h. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
i. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
j. The proposed small generator facility must not exceed the capacity of the existing service.
k. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company shall, within 20 business days of an interconnection application being deemed complete:
   a. Evaluate the request using the Level 2 review criteria

  b. Review the applicant's analysis, if provided by the applicant, using the same criteria, and
  c. Provide the applicant the Company's evaluation, including a comparison of the results of its own analysis with those included with the application.

5. Within 5 days of an approved, or conditionally approved Level 2 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. For approved requests, the Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   b. The Witness Test has been performed and successfully completed.

7. A conditionally approved interconnection application is an interconnection request that may be approved under Level 2 criteria with minor modifications to the Company's EDS, however the application has failed one or more of the evaluation elements listed previously. The Company will provide the applicant with a letter that includes an Interconnection Agreement and a listing of the milestones needed to be completed for the facility to be connected to the Company's EDS.
   a. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions being completed:
      i. All milestones agreed to the in the Interconnection Agreement are satisfied.
      ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
      iii. A Witness Test has been performed and successfully completed.

8. If the Level 2 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 2 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 3 or Level 4 review. The line section queue position assigned to the Level 2 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VI. LEVEL 3 REVIEW PROCEDURES:

An application interconnection request submitted under Level 3 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the interconnection request using the following criteria:
   a. The total of the nameplate capacity of all generators on the circuit, including the proposed small generating facility, is 10 MW of less.
   b. The small generator will use reverse power relays or other protection that prevent power flow onto the EDS.
   c. The small generator facility is not served by a shared transformer.
   d. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company will evaluate the application and provide a response to the Applicant within 20 business days of a completed application form.

5. Within 5 days of an approved Level 3 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned by the interconnection applicant within 30 business days from the receipt of the response or deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. All milestones agreed in the Interconnection Agreement are satisfied.
   b. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   c. The Witness Test has been performed and successfully completed.

7. If the Level 3 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 3 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 4 review. The line section queue position assigned to the Level 3 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VII. LEVEL 4 REVIEW PROCEDURES:

An application interconnection request submitted under Level 4 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the Applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. A Level 4 application that is deemed incomplete shall have 10 business days to provide the data necessary to complete the interconnection request or the application will be deemed withdrawn from the process.

4. Once the Interconnection Application is deemed complete, the Company shall use the following metrics in performing a Level 4 review:
   a. With an agreement between the parties, the scoping meeting, interconnection feasibility study, interconnection impact study, or interconnection facilities study provided for in a Level 4 review may be waived.

   b. If agreed to by the parties, a scoping meeting will be held within 10 business days of the notification to the applicant that the interconnection application is complete, or the applicant has requested that its interconnection request proceed after failing the requirements of a Level 2 or Level 3 review.

   c. The scoping meeting will provide what is needed to proceed with a feasibility study and any further analysis of the proposed generator interconnection request. Any previous study results or other pertinent information will also be reviewed at the scoping meeting to determine the need for additional studies.

   d. An Interconnection Feasibility Study may be performed to determine if the project is feasible to interconnect with Montana-Dakota's EDS.

      If the parties agree that an Interconnection Feasibility Study shall be performed, the Company shall provide to the applicant, no later than 5

business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Feasibility Study shall include any of the following analyses necessary for the purpose of identifying any potential adverse system impacts on the EDS:

i. Initial identification of circuit breaker short circuit limits exceeded.
ii. Initial identification of any thermal overload issues
iii. Initial identification of any voltage limit issues
iv. Initial review of any grounding requirement and system protection concerns
v. A non-binding rough estimate of the costs of facilities required to interconnect the proposed generator to the EDS.

e. An Interconnection System Impact Study may be performed to review the system impacts of the proposed small generator on Montana-Dakota's EDS.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study is not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection System Impact Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

An Interconnection System Impact Study shall evaluate the impact of a proposed small generator on the Company's EDS on both the reliability and safety issues related to the proposed generator. Consideration of any studies that an applicant has provided will be reviewed and analyzed. The impact study shall include any necessary elements from among the following:

i. A load flow study
ii. Identification of the affected systems
iii. An analysis of equipment interrupting ratings
iv. A protection coordination study

v. Voltage drop and flicker studies
vi. Grounding reviews
vii. System operations impacts
viii. A short circuit analysis
ix. A stability analysis

f. An Interconnection Facilities Study shall be performed to estimate the cost of the equipment, engineering, procurement, and construction work, including overheads, needed to implement the conclusions of the Interconnection Feasibility Study and/or the Interconnection System Impact Study to interconnect the proposed small generator facility.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study and an Interconnection System Impact Study are not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection Facilities Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Facilities Study shall identify the following:

i. The electrical switching configuration of the equipment, including transformer, switchgear, meters, and other station equipment.
ii. The nature and estimated cost of the Company's EDS changes required to interconnect the proposed small generator facility.
iii. An estimate of the time required to complete the construction and installation of the required facilities on the EDS.

g. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection can be made to the EDS, the Company will send a response letter to the applicant with an Interconnection Agreement for Small Distribution Generator Facility, including the requirement details associated with the proposed installation.

h. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection cannot be made to the EDS, the Company will send a response letter to the applicant indicating the reasons for the denial of the application.

i. The applicant will have 30 business days after the receipt of an interconnection agreement to sign and return the agreement. When an applicant does not sign and return the application within 30 business days, the interconnection request shall be deemed withdrawn.

j. The interconnection agreement will be final only when:
   i. The milestones agreed to in the Interconnection Agreement for Small Distribution Generator Facility are satisfied.
   ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   iii. The Witness Test has been performed and successfully completed.

VIII. GENERAL INTERCONNECTION PROVISIONS:

1. APPLICANT'S RESPONSIBILITY:
   a. The interconnection applicant is responsible for the construction of all generator facilities and the securing of any necessary approvals or permits from local, state, and federal authorities.

   b. The costs associated with the interconnection application and agreement are the responsibility of the interconnection applicant. This includes any application fees, the cost of various studies required, and any construction of facilities on the Electric Distribution System needed to accommodate a proposed small generator facility. The Company will not charge the applicant for the required Witness Test.

2. Existing capacity or construction of capacity by the Company on its EDS is not required to accommodate small generator facilities.

3. Interconnection facilities approved and installed under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

4. DISCONNECTION DEVICE:
The proposed interconnection design of a Small Generator Facility must include a disconnect device installed, owned, and maintained by the customer to be used by the Company in the event of system operation maintenance or an emergency event. The disconnect device shall be capable of interrupting and isolating the small generation facility equipment from the Company's EDS. This device must allow for a visible break, must have the ability to be locked open, and must be accessible to the Company at all times for use. The location shall be within ten (10) feet of the metered service point unless special permission is granted by Montana-Dakota. The disconnection device shall be documented on the Interconnection Agreement.

5. METERING:
Changes to or the addition of metering equipment to properly account for the generation and use of power at the interconnection site will be communicated by the Company in the application process. The customer will be responsible for the installation, costs, and maintenance of any load wiring, meter sockets, cabinets, etc. required for the accommodation of meters, instrument transformers, test switches, or other meter devices provided by and maintained by the Company. The additional or required metering changes shall be documented on the Interconnection Agreement.

6. TECHNICAL STANDARDS:
Unless otherwise noted in this tariff, the technical standard to be used in evaluating all interconnection requests shall be the IEEE Standard 1547-2003 version.

7. WITNESS TEST:
   A witness test shall be required as part of the installation and approval of any proposed interconnection to the Company's EDS. This test is required to assure the small generator facility is operating within the characteristics of the equipment as proposed and certified along with an assurance that no operational interference is affecting any other customer's service on the Company's EDS. The applicant shall give the Company a 10-day notice to schedule this Witness Test of the small generator facility. This test may be performed at the commissioning startup of the proposed facility and a successful test is required to gain final approval of the interconnection agreement.

   The Witness Test at a minimum shall require:
   a. Verification of the Equipment proposed and declared on the Application Request.
   b. Verification of the location and access of the Disconnection Device.
   c. A Power Recording Device installation at the interconnection point to record a period of time the small generator facility is operating in parallel to the EDS.
   d. Verify that a loss in EDS voltage to the system allows for proper interruption of the generation voltage to the EDS. (Islanding Test)
   e. Any other test stipulated in the Interconnection Agreement.

   If the witness test is not acceptable, the Company shall send a written report to the applicant within 5 business days of the end of the witness test period. The applicant shall be granted 30 business days to address and resolve any deficiencies. If the applicant fails to address and resolve the deficiencies to the satisfaction of the Company, the interconnection request will be deemed withdrawn.

8. INSPECTION AND TESTING OF FACILITY:
   a. Future testing of an approved facility may be performed under the following circumstances:
      i. An annual test for Level 2 and Level 3 approved facilities

ii. Mutually agreed upon intervals for Level 4 approved facilities and any necessary testing specified by the manufacturer.

b. The Company shall have the right to inspect a customer generator facility before and after the interconnection approval is granted. This right to inspection is to be performed at reasonable hours and with reasonable prior notice provided to the customer.

9. MONITORING OF INTERCONNECTION EQUIPMENT:
The Company may require monitoring or control of a small generator facility if the nameplate capacity rating of the small generator facility interconnecting to the EDS, or the aggregate nameplate capacity of all small generator facilities on the line section in combination with the proposed small generator facility interconnecting to the EDS, is greater than 15% of the line section annual peak load as most recently measured at the substation or exceeds the annual minimum load of the line section.

10. DISCONNECTION OF SERVICE:
   a. The Company shall have the right to disconnect the customer generator facility at any time during an emergency on the EDS.
   b. If the Company discovers that the customer generator is not in compliance with the requirements of IEEE Standard 1547-2003, and the noncompliance adversely affects the safety or reliability of the EDS, the Company may require the disconnection of the customer generator facility until it complies. The Company will provide the customer with a written report of the details of how the customer generator facility is not complying with IEEE 1547-2003 or the Administrative Rules of the State of Montana (Small Generator Interconnections).
   c. The Company shall have the right to disconnect unauthorized small generator interconnections to the Company EDS upon discovery.

11. DISPUTE RESOLUTION:
    Either the Company or Customer Generator shall attempt to resolve all disputes regarding a small generator facility interconnection promptly, equitably, and in a good faith manner.

    When a dispute cannot be resolved, a party may seek immediate resolution through complaint procedures available through the Montana Public Service Commission.

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 1)

APPLICATION SCOPE:

LEVEL 1 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 50 KW in size utilizing inverter based certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96).

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Small Generator Facility Information

INVERTER

Inverter Manufacturer: ☐ Model: ☐

Inverter Electric Nameplate Capacity: ☐ (KW) ☐ (KVA)

Inverter Electrical Connection: ☐ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for inverters by a Nationally Recognized Testing Laboratory (NRTL)

GENERATOR

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐ Turbine ☐

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐ Fuel Oil ☐

Generator Comments ☐

Total System Design Capacity: ☐ (KW) ☐ (KVA)

SITE Information

This application is requested for: ☐ A New Small Generator to be located on an Existing Service.
☐ A New Small Generator to located at a New Service.
☐ A Change to an Existing Small Generator Location.

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Estimated Commissioning Date:

Interconnection Address/Location:

MDU Premise/Account (MDU USE):

Note: The Required Disconnect Switch must be able to be locked open and shall be located within 10 (Ten) feet of the meter location unless special permission is granted by the company.

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach a One-Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), and Disconnect Switch.

☐ - Completed Net Metering Application Addendum "A"

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $50.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________________

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Title: ______________________ Date: ______________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate: YES☐ NO ☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 2)

APPLICATION SCOPE:

LEVEL 2 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 2 MW in size and must utilize certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96). Also, Interconnections that were reviewed under Level 1 review procedures but not approved, can be re-submitted under a new Level 2 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

SITE INFORMATION

This application is requested for: ☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location: ______________________

MDU Premise/Account (MDU USE ONLY): ______________________

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: ________ Amps Voltage: ________ Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date:
____

Small Generator Facility General Information

Prime Mover: Photovoltaic ☐
Reciprocating Engine ☐
Fuel Cell ☐
Turbine ☐
Micro Turbine ☐
Other ______________

Energy Source: Solar ☐
Wind ☐
Hydro ☐
Diesel ☐
Natural Gas ☐
Steam ☐
Fuel Oil ☐
Other ______________

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Generator Nameplate Rating: ______ KW ______ KVAR

Total Expected Generation Export ______ KW ______ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ______ (KW) ______ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

CERTIFIED EQUIPMENT LISTING – List interconnection components/systems to be used in the Small Generation Facility that is NRTL Certified. (required for Lab Tested Certification of Interconnection Equipment) Please included information for all certified equipment components.

Component/System	NRTL Providing Label – Listing

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach Information from All Other Certified Interconnection Equipment Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Complete Net Metering Application Addendum "A" (If Applicable)

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ - Attach a One-Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC:

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $200.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________________

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Title: ______________________ Date: ______________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate 92: YES☐ NO☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

*** Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non-Salient Rotor ☐

Torque: ______ Ft-Lb Rated RPM: ______

At Rated Generator Voltage and Current: Field Amperes: ______ Amps @ ______ %PF

Type of Exciter: ______

Output Power of Exciter: ______

Type of Voltage Regulator: ______

Locked Rotor Current: ______ Amps Synchronous Speed: ______ RPM

Winding Connection: ______

Min. Operating Frequency/Time: ______

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): ______ Ohms (P.U.)

Direct-axis Transient Reactance (X'd): ______ Ohms (P.U.)

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Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Direct-axis Sub-Transient Reactance (X"d): ______ Ohms (P.U.)

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

Locked Rotor Current: ______ Amps Base KVA: ______ KVA

Rotor Resistance (Rr): ______ Ohms Exciting Current: ______ Amps

Rotor Reactance (Xr): ______ Ohms Reactive Power Required: ______

Magnetizing Reactance (Xm): ______ Ohms ______ VAR's (No Load)

Stator Resistance (Rs): ______ Ohms ______ VAR's (Full Load)

Stator Reactance (Xs): ______ Ohms

Short Circuit Reactance (Xd): ______ Ohms

K (Heating Time Constant): ______ Total Rotating Inertia H: ______ KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: ______ Design Letter: ______ Temp. Rise: ______ °C

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Levels 3 & 4)

APPLICATION SCOPE:

LEVEL 3 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 MW in size and where power will not be exported beyond the interconnection point. This could be used as a demand control generator for customer load.

LEVEL 4 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 Megawatts (MW) in size, and does not qualify under the criteria of LEVEL 1, LEVEL 2, and LEVEL 3. This includes any Interconnection Request that was submitted and not approved under a LEVEL 1, LEVEL 2, or LEVEL 3 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

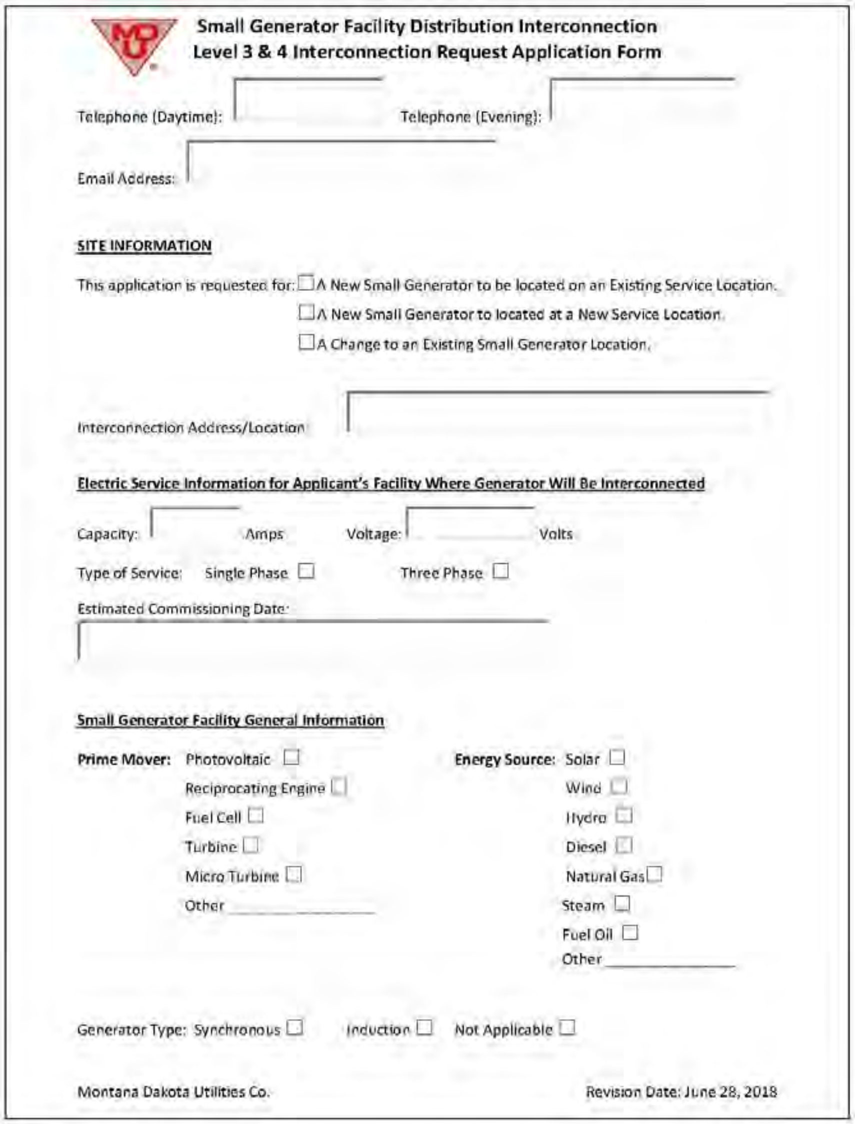
System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:



Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Telephone (Daytime): Telephone (Evening):

Email Address:

SITE INFORMATION

This application is requested for: ☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: Amps Voltage: Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date:

Small Generator Facility General Information

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐ Turbine ☐ Micro Turbine ☐ Other ________

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐ Steam ☐ Fuel Oil ☐ Other ________

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Generator Nameplate Rating: ____ KW ____ KVAR

Total Expected Generation Export ____ KW ____ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ____ Model: ____

Inverter Electric Nameplate Capacity: ____ (KW) ____ (KVA)

Inverter Electrical Connection: ____ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ____ (KW) ____ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes. (If Applicable)

☐ - Complete Equipment Detail Addendum "A" – Prepare Lists and Attach Detailed information.

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ - Attach a Site Diagram of the Proposed System location indicating the locations of all proposed equipment at the Small Generator Site. This should include at a minimum, generator locations, electrical equipment, disconnect location, transformers, meters, and all other system related locations.

☐ - Attach a One-Line Diagram of the Proposed System that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch. Also include relay protection, control schematics, current and potential circuits, and alarm/monitoring circuits.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC: ______

Note: An application Deposit is required before the application can be processed. The actual cost of the studies and reviews necessary to provide for this Interconnection is the responsibility of Interconnection Applicant.

Application Deposit Included: ☐ Amount: $500.00 Deposit

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______

Title: ______ Date: ______

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

GENERATOR CONNECTION

Transformer

Is there a Transformer needed between the Generator and Service Connection Point Yes ☐ No ☐

Transformer Detail: 3 Phase ☐ 1 Phase ☐

Capacity: ______ KVA Impedance: ______ % on BASE: ______ KVA

PRIMARY: Voltage: ______ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

SECONDARY: Voltage: ______ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

Power Circuit Breaker

Manufacturer: ______

Type: ______

Load Amp Rating: ______ Interrupting Amp Rating: ______

Trip Speed: ______ Cycles

Interconnection Relays

If Conventional individual relay: Attach a List and Include the following for each relay:

Manufacture, Model, Catalog Number, Function, Proposed Setting

If Microprocessor Controlled: List the following for each Setpoint:

Setpoint Function, Minimum, and Maximum Settings – Proposed Settings.

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

Auxiliary Transformers

Current Transformers (If Applicable and for each Bank of Current Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, and Burden.

Potential Transformers (If Applicable and for each Bank of Potential Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, Thermal Rating, and Burden.

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer: ____

Model Number: ____ Version Number: ____

*** Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non Salient Rotor ☐

Torque: ____ Ft-Lb Rated RPM: ____

At Rated Generator Voltage and Current: Field Amperes: ____ Amps @ ____ %PF

Type of Exciter: ____

Output Power of Exciter: ____

Type of Voltage Regulator: ____

Locked Rotor Current: ____ Amps Synchronous Speed: ____ RPM

Winding Connection: ____

Min. Operating Frequency/Time: ____

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): ____ Ohms (P.U.)

Direct-axis Transient Reactance (X'd): ____ Ohms (P.U.)

Direct-axis Sub-Transient Reactance (X"d): ____ Ohms (P.U.)

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

Locked Rotor Current: ______ Amps Base KVA: ______ KVA

Rotor Resistance (Rr): ______ Ohms Exciting Current: ______ Amps

Rotor Reactance (Xr): ______ Ohms Reactive Power Required: ______

Magnetizing Reactance (Xm): ______ Ohms ______ VAR's (No Load)

Stator Resistance (Rs): ______ Ohms ______ VAR's (Full Load)

Stator Reactance (Xs): ______ Ohms

Short Circuit Reactance (Xd): ______ Ohms

K (Heating Time Constant): ______ Total Rotating Inertia H: ______ KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: ______ Design Letter: ______ Temp. Rise: ______ °C

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection

Interconnection Feasibility Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ________________________________ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Feasibility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection Feasibility Study as Attachment "A" attached to this agreement.

4. The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Applicant in its Application, as may be modified as the result of the Scoping Meeting. Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application, the time to complete the Interconnection Feasibility Study may be extended by mutual agreement of the Parties.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The Feasibility Study and Report will include the following analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the Interconnection;

ii. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

iii. Initial review of grounding requirements and system protection; and

iv. A Description and non-binding estimated cost of facilities required to interconnect the Small Generator Facility to Montana-Dakota's Electric Distribution System in a safe and reliable manner.

7. The Interconnection Feasibility Study shall be completed and the results transmitted to the Interconnection Applicant within 30 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Feasibility Study Report within the 30-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

8. The Interconnection Applicant is responsible for the Feasibility Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Feasibility Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Small Generator Facility Distribution Interconnection

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____

Signed: ____

Title: ____

Date: ________________

[Insert name of Applicant]

Name (Printed):____

Signed: ____

Title: ____

Date: ________________

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Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions in regard to a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________

Interconnection Feasibility Study Estimated Cost: $

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Small Generator Facility Distribution Interconnection

Interconnection System Impact Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ____, ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ________________________________, and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"), and

Whereas, Montana-Dakota has completed a Small Generator Interconnection Feasibility Study and provided the results in the form of a Report to the Interconnection Applicant or the Feasibility Study was waived by mutual agreement of the Parties, and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection System Impact Study to assess the impact of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System:

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection System Impact Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection System Impact Study as Attachment "A" and attached to this agreement.

Montana Dakota Utilities Co. Revision Date: June 28, 2018

4. The Interconnection System Impact Study shall be based on the technical information provided by the Interconnection Applicant in its Application, results of the Feasibility Study Report (if performed), and any information agreed upon as a result of the Scoping Meeting Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the System Impact Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application Information or the technical information, the time to complete the Interconnection System Impact Study may have to be extended.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The System Impact Study will include the following detailed analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Short Circuit Analysis
ii. A Power Flow Analysis
iii. Verification of Interruption Equipment Ratings
iv. Protection Coordination Study
v. Voltage Drop and Flicker Study
vi. Effective Grounding Review
vii. System Stability Analysis
viii. Review of Set Points of Certified Equipment
ix. A Review of the Interconnection Impact on the EDS Operations.

7. The System Impact Study Report shall state the assumptions upon which it is based, state the results of the analyses, indicate any interconnection requirements or impediments, and will include preliminary changes and costs required to the Montana-Dakota Electric Distribution System in order to implement the Interconnection request. The System Impact Study preliminary changes and costs will include a list of facilities and changes that are required as a result of the Interconnection request and a non-binding good faith estimate of cost responsibility and time to construct.

8. The Interconnection System Impact Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Interconnection System Impact Study within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

Small Generator Facility Distribution Interconnection

9. The Interconnection Applicant is responsible for the Interconnection System Impact Study costs. The Study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection System Impact Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

[Insert name of Applicant]

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection System Impact Study Estimated Cost: $

Small Generator Facility Distribution Interconnection

Interconnection Facilities Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ______________________________________ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, Montana-Dakota has completed a Small Generator Interconnection System Impact Study and provided the results in the form of a Report to the Interconnection Applicant; and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Facilities Study to list and provide estimate for all the costs and timing of system changes to implement the conclusions of the Interconnection System Impact Study in order to safely Interconnect the proposed small generator to the Electric Distribution System. This estimate would include any distribution equipment, metering equipment, operational impacts, or other costs associated with the operation of the new proposed interconnection on the Montana-Dakota Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Facility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

Small Generator Facility Distribution Interconnection

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information specific to or affecting the Interconnection Facilities Study as Attachment "A" and filed with this agreement.

4. The Interconnection Facilities Study shall include a detailed specification and listing of any system equipment, metering equipment, operational costs (including overheads), or other costs (including overheads) required to safely interconnect the proposed small generator interconnection to the Montana-Dakota Electric Distribution System. Details of the Interconnection Facilities Study Report will include a listing of the required equipment, the electrical configuration of the Interconnection system estimate, an estimate of the specific costs of each item, and the estimate of the timing required to performing the system changes estimated for the interconnection.

5. The Interconnection Facilities Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Facilities Study Report within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

6. The Interconnection Applicant is responsible for the Interconnection Facilities Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection Facilities Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Montana Dakota Utilities Co. Revision Date: June 28, 2018

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____________________________________

Signed: ____

Title: ____

Date: _____________

[Insert name of Applicant]

Name (Printed):____________________________________

Signed: ____

Title: ____

Date: _____________

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, Feasibility Study, System Impact Study, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection Facilities Study Estimated Cost: $

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

This Interconnection Agreement ("Interconnection Agreement" or "Agreement") is entered into effective as of Click or tap to enter a date., ("Effective Date") by and between Click or tap here to enter the name of the Applicant for this Interconnection Agreement., ("Applicant") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, the Applicant is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on *Click or tap to enter a date.*;

Whereas, the Applicant desires to interconnect the Small Generator Facility with the Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, the Agreement shall be used for all approved Level 1, Level 2, Level 3, and Level 4 Applications according to the terms and procedures set forth in Montana-Dakota's Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff (Rate 96). Terms with initial capitalization, when used in this Agreement, shall have the meanings given in Rate 96 and, to the extent this Agreement conflicts with Rate 96, the Rate 96 tariff shall take precedence.

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Scope

The Agreement establishes standard terms and conditions approved by the Montana Public Service Commission (the "Commission") under which the Small Generator Facility with a Name Plate Capacity of 10 MW or smaller will interconnect to, and operate in Parallel with Montana-Dakota's EDS. Additions, deletions, or changes to the standard terms and conditions of an Interconnection Agreement will not be permitted unless they are mutually agreed to by the Parties and approved by the Commission if required by Rate 96.

1.2 Power Purchase

The Agreement does not constitute an agreement to purchase or deliver the Applicant's power nor does it constitute an electric service agreement.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

1.2.1 **Other Agreements.**
Nothing in the Interconnection Agreement is intended to affect any other agreement between the Montana-Dakota and the Applicant or another Interconnection Customer. However, in the event that the provisions of the Agreement are in conflict with the provisions of other Montana-Dakota tariffs, the Montana-Dakota tariff shall control.

1.3 **Attachments to Interconnection Agreement**

An Operations and Maintenance Schedule shall be attached to the Interconnection Agreement and the Applicant shall adhere to that schedule. Either Party may require that any of the following addendums be included as part of the Interconnection Agreement:

(A) Copy of the Interconnection Application
(B) Description of the project;
(C) a Billing Schedule;
(D) a List of non-binding milestones for each party;
(E) Scope of Work;
(F Operational Guidelines; and
(G) List of Major Permits needed by the Applicant.
(H) Assignment Acknowledgement Agreement

1.4 **Responsibilities of the Parties**

The Parties shall perform all obligations of the Agreement in accordance with all applicable laws and rules.

The Applicant will construct, own, operate, and maintain its Small Generator Facility in accordance with the Agreement, the IEEE Standard 1547-2003 version, the most currently adopted National Electric Code, state and federal law, and all other applicable standards required by the Commission. Each Party shall be responsible for the safe installation, maintenance, repair, and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and personal injury.

To the extent applicable, the allocation of responsibility for the design, installation, operation, maintenance, and ownership of Interconnection Facilities shall be as prescribed in Rate 96.

1.5 **Parallel Operation and Maintenance Obligations**

Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of the Interconnection Agreement, the Applicant will abide by all written provisions for operation and maintenance as required by Montana-Dakota.

1.6 **Power Quality**

The Applicant will design its Small Generator Facility to maintain a composite

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. Any special operating requirements will be detailed in an attached form. Under no circumstances shall these additional requirements for voltage or reactive power support exceed the normal operating capabilities of the Small Generator Facility.

Article 2 **Inspection, Testing, Authorization, and Right of Access**

2.1 Testing and Inspection

Applicant will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in Rate 96. The Interconnection will not be final until the Witness test and certificate of completion provisions in Rate 96 have been satisfied or waived in accordance with Rate 96.

To the extent that an Applicant decides to conduct interim testing of the Small Generator Facility prior to the witness test, it may request that the Montana-Dakota observe these tests and that these tests be deleted from the final witness test. If Montana-Dakota sends qualified personnel to the Small Generator Facility to observe such interim testing, it will be doing so at the Company's own expense.

2.2 Right of Access:

Montana-Dakota will have access to the Applicant's premises, at no cost, for any reasonable purpose in connection with the Interconnection Application, the Interconnection Agreement, or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency, hazardous condition, or violation of the terms of this agreement.

Article 3. **Effective Date, Term, Termination, and Disconnection**

3.1 Effective Date

The Agreement shall become effective upon the Effective Date stated in the introductory paragraph.

3.2 Term of Agreement

The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or another period mutually agreed to by Parties in a written amendment, unless terminated earlier by default of either Party, voluntary termination by the Interconnection Customer, or by action of the Commission.

3.3 Termination

The Applicant may terminate this Agreement at any time by giving Montana-Dakota twenty (20) business days written notice. Either Party may terminate

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

this Agreement pursuant to Section 5.6.2 after default by the other Party. The Commission may order termination of this Agreement. Upon termination of this Agreement, the Small Generator Facility will be disconnected from Montana-Dakota's EDS at the Applicant's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination. The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Restoration of Interconnection When Disconnected

The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Montana-Dakota's EDS to their normal operating state as soon as reasonably practicable following any disconnection pursuant to the rules.

Article 4. Cost Responsibility and Billing

The Applicant is responsible for the application fee, cost of studies, and for such facilities, equipment, modifications, and upgrades identified under the process prescribed in Rate 96.

4.1 Minor EDS Modifications

The Applicant will bear the costs of making minor modifications to Montana-Dakota's EDS as may be necessary to gain approval of an Application.

4.2 Interconnection Facilities (Company Owned)

When necessary under the process prescribed in Rate 96, Montana-Dakota will identify the interconnection facilities ("Interconnection Facilities") necessary to safely interconnect the Small Generator Facility with the EDS. Montana-Dakota will itemize the Interconnection Facilities for the Applicant, including the cost of the facilities and the time required to build and install those facilities. The Applicant is responsible for the cost of the operational changes or physical additions to the Company-owned Interconnection Facilities.

4.3 Interconnection Equipment (Customer Owned)

The Applicant is responsible for all costs associated with the installation, operation and maintenance of the interconnection equipment not owned by the Company

4.4 System Upgrades

Montana-Dakota will design, procure, construct, install, and own any System Upgrades under the process prescribed in Rate 96 when applicable. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Applicant. An Interconnection Customer may be entitled to financial compensation from other utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the

Commission or by terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 Adverse System Impact

Montana-Dakota is responsible for identifying adverse system impacts on any affected systems and for determining what mitigation activities or upgrades may be required to accommodate a Small Generator Facility. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Applicant. The Applicant may be entitled to financial compensation from other utility Interconnection Customers or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Applicant, to the extent provided by a tariff or a separate Commission rule or order.

4.6 Billing

Montana-Dakota may require a deposit up to 50% of the cost estimate to be paid up front by the Applicant, for the studies, interconnection facilities, system upgrades, or other costs associated with the interconnection request. Progress billing, final billing, and payment schedules must be agreed to by the Parties prior to commencing work. The Billing Schedule should be attached to the agreement as "Attachment C" as needed.

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment

The Interconnection Agreement may be assigned by either Party upon fifteen (15) business days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

5.1.2 The Applicant shall have the right to assign the Agreement, without the consent of Montana-Dakota, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement. Attachment (H) can be used to document the assignment of a new owner to an existing facility.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

5.1.3 Any attempted assignment that violates this Article is void and ineffective.

5.2 **Limitation of Liability and Consequential Damages**

A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees caused by any act or omission in its performance of the provisions of an Interconnection Agreement. Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 **Indemnity**

5.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of the Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article, as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle, or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.4 **Consequential Damages**

With the exception of third party claims, neither Party shall be liable to the other Party, under any provision of the Agreement, for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to

the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 **Force Majeure**

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. If the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by Rule that the Rule does not permit the Parties to mutually waive.

5.6 **Default**

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement. Upon a default, the non-defaulting Party shall give written notice of such default to the defaulting Party. Except as provided in Article 5.6.2, the defaulting Party shall have sixty (60) calendar days from receipt of the default notice within which to cure such default.

5.6.2 If a default is not cured as provided for in this Article, or if a default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate the Agreement by written notice, and be relieved of any further obligation hereunder and, whether or not that Party terminates the Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternately, the non-

defaulting Party shall have the right to seek dispute resolution with the Commission in lieu of termination. The provisions of this Article will survive termination of the Agreement.

Article 6. **Insurance**

At all times during this Agreement, each Party shall obtain and maintain the following insurance:

General Liability Insurance with limits not less than $1,000,000. Limits may be met in combination of both primary and umbrella/excess policies. Upon signing the Agreement, each Party shall furnish to the other Party certificates of insurance as evidence showing that the insurance policy(s) to be carried in accordance with this provision have been obtained. All insurance to be carried pursuant to the above shall be endorsed to require 30 day written notice prior to effective date of any modification or cancellation of such insurance to the certificate holder, unless such cancellation is due to non-payment, then 10 day written notice is required.

Article 7. **Dispute Resolution**

Parties will adhere to the dispute resolution and complaint process in Rate 96.

Article 8. **Miscellaneous**

8.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation, and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Montana, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 Amendment

The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of Rate 96 and applicable Commission Orders and provisions of the laws of the State of Montana.

8.3 No Third-Party Beneficiaries

The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

8.4 Waiver

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by Rate 96.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 **Entire Agreement**

The Interconnection Agreement, including any supplementary form attachments that may be necessary, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under the Agreement.

8.6 **Multiple Counterparts**

The Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 **No Partnership**

The Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 **Severability**

If any provision or portion of the Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of the Agreement shall remain in full force and effect.

8.9 **Subcontractors**

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

Nothing in the Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in the Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under the Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of the Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under the Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by the Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

Either Party will have the right to make a unilateral filing with the Commission to modify the Interconnection Agreement. This reservation of rights provision includes, but is not limited to, modifications with respect to any rates, terms, and conditions, charges, classification of service, tariff, or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. Notices

9.1 General

Unless otherwise provided in the Agreement, any written notice, demand, or request required or authorized in connection with the Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the persons specified below:

If to the Interconnection Applicant:

Attention: ______________________

Address: ____

City: ______________________ State: __________ Zip: ______

Phone: ______________ E-mail: ______________

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

If to the Interconnection Applicant:

Attention: ______________________________

Address: ______________________________

City: __________________ State: __________ Zip: ______

Phone: ______________ E-mail: ______________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.3 Designated Operating Representative

The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of the Agreement. This person or persons will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

If to the Interconnection Applicant:

Attention: ______________________________

Address: ____

City: ___________________________ State: ____________ Zip: _______

Phone: ____________________ E-mail: ___________________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.4 Changes to the Notice Information

Either Party may change this notice information by giving five business days written notice prior to the effective date of the change.

Article 10 Signatures

IN WITNESS WHEREOF, the Parties have caused the Agreement to be executed by their respective duly authorized representatives.

Montana-Dakota	Interconnection Applicant
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________
Signature: ____________________	Signature: ____________________
Date: ____________________	Date: ____________________

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

ADDENDUM "H" ASSIGNMENT ACKNOWLEDGEMENT AGREEMENT

APPLICATION SCOPE: For a Small Generator System that is incorporated into a building facility that has a current active Interconnection Agreement for Small Distribution Generator Facility approved by Montana Dakota Utilities Company. The Small Distribution Generator Facility Agreement will automatically transfer to the new owner upon the sale of the property and completion of this Assignment Acknowledgement Agreement by the New Owner-Operator. A copy of the original Interconnection Agreement will be sent to the New Owner-Operator for the purpose of this agreement.

Recitals:
Whereas, an existing Small Distribution Generator Facility is located at: ____________________ ______________________ (the "Property"), and operates pursuant to an Interconnection Agreement for Small Distribution Generator Facility dated the ______ day of __________, 20____ (the "Agreement") with Montana-Dakota Utilities Company, a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Whereas, a new owner has purchased the "Property" and desires to operate the Small Generator System under the same requirements set forth in the "Agreement".

Whereas, a copy of the original Interconnection Agreement is attached to this Acknowledgement Agreement.

AGREEMENT
Now, therefore, the New Owner-Operator is assigned and assumes all rights and obligations under the "Agreement".

Montana-Dakota - Acknowledgement	New Owner-Operator
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________
Signature: ____________________	Signature: ____________________
Date: ____________________	Date: ____________________

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I. PURPOSE:

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

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of Montana (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 Montana.

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 expressed 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 and water well pumps on the same premise as the living quarters, used for single family 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 nonresidential 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 salons, 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. CUSTOMER 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 for residential service shall not exceed one-sixth of the estimated annual billings. For non-residential

service, the amount of the deposit shall not exceed 25 percent of the estimated annual billings.

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

iii. Interest on deposits held shall be accrued at the rate of .5 percent per month. Interest shall be computed from the receipt of deposit to the time of refund or of termination. Interest shall be credited to the customer's account annually during the month of December.

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

3. LATE PAYMENT CHARGE:
Amounts billed for energy will be considered past due if not paid by the due date shown on the bill.

   i. For residential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the second subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment

arrangement, an amount equal to 1% of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

ii. For nonresidential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date.

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

4. RETURNED CHECK CHARGE:
A charge of $30.00 will be collected by the Company for each check not honored by customer's financial institution for any reason.

5. MANUAL METER CHECK CHARGE:
A charge of $18.35 will be assessed monthly for 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. Customers 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 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 or other political subdivision for the privilege of conducting its utility operations therein.

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

7. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS: For service requested by customer for cut-ins, cut-outs, and disconnection or reconnection of service after the Company's regular business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and material at retail prices.

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

   To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply unless service can be scheduled for a future workday.

8. RECONNECTION FEE FOR SEASONAL CUSTOMER: 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. All bills for services 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 Montana Public Service Commission.

   ii. The Company may collect a fee of $20.00 before restoring electric service which has been disconnected for nonpayment of service bills.

10. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILL:
    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. BILLING ERRORS:
Billing error means any bill issued by Company that is not designated as an estimate and that understates the amount owed by the customer. It also means the Company's failure to bill a customer, although there was energy consumption which would, under the Company's normal billing practices, be billed to the customer.
    i. When a billing error is discovered which is not the result of theft by the customer, the Company may submit a bill to the customer based

on the corrected information for a period not to exceed six months from the date the billing error is discovered.

ii. Billing errors on accounts of industrial customers are not limited to the six-month period applicable to all other customers.

14. INSTALLING TEMPORARY METERING OR SERVICE FOR ELECTRIC FACILITY:
A customer requesting temporary metering service will be charged on a time and material basis in accordance with Electric Service Rules and Regulations Rate 110.

15. SERVICES ON CUSTOMER PREMISES – ELECTRIC NONCHARGEABLE – UTILITY SERVICES:
    i. Fire Call
    ii. Investigate hazardous condition on customer premises
    iii. No lights or power investigation
    iv. Maintenance or repair of Company-owned equipment on the customer's premise –
        a. Meter
        b. Overhead service line
        c. Underground service line
    v. Checking voltage or loads
    vi. Locating radio, cb or television interference
    vii. High bill complaint
    viii. Cut-ins and cut-outs (regular work hours)

16. MODIFICATION OF RATES, RULES AND REGULATIONS:
Company reserves the right to modify any of 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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Section 100 - General

101. 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 Commission 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.

102. 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.

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. Any customer may be required to make a deposit as required by the Company. 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.

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. The Company will make reasonable effort to contact the customer, but the Company reserves the right to interrupt service to conduct maintenance on metering equipment, including an exchange of the meter.

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 customer's premise. It is the obligation of the customer to consult with the Company regarding maximum available 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 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 hold 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 conduit 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 results 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 (Only allowed by special request – see Section 302.3)
**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 Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in 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 may not be 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 Electrical 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 150feet, 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 actual 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 the 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. The customer will utilize meter sockets from a Company approved list of manufacturers and models as posted on the Company's website. 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. U.L. approved, ringless style.
2. 100 ampere minimum for overhead service installations.
3. 150 ampere minimum for underground service installations.
4. Stud connectors are required for all sockets rate 320 amps or greater.
5. For sockets rated below 320 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.

7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
8. 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. Customer must provide hub closing plate.
4. Automatic by-pass feature is not acceptable.

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. For 480 volt service, enclosures must be sized to include room to mount voltage transformers or a separate weatherproof enclosure may be provided by the customer to mount 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 rated disconnect 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 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.

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 place on the exterior of the meter base on a non-removal 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 the 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 Commission.

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.

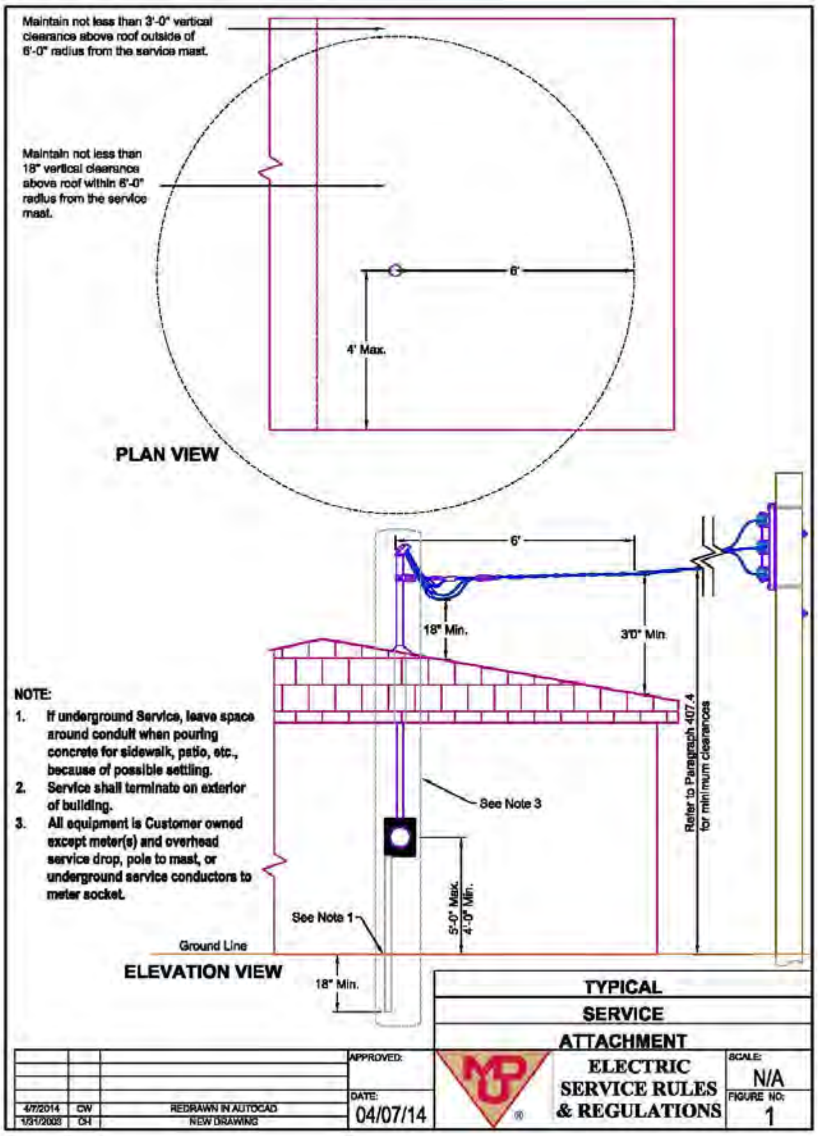
707. Flashing Display Signs
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

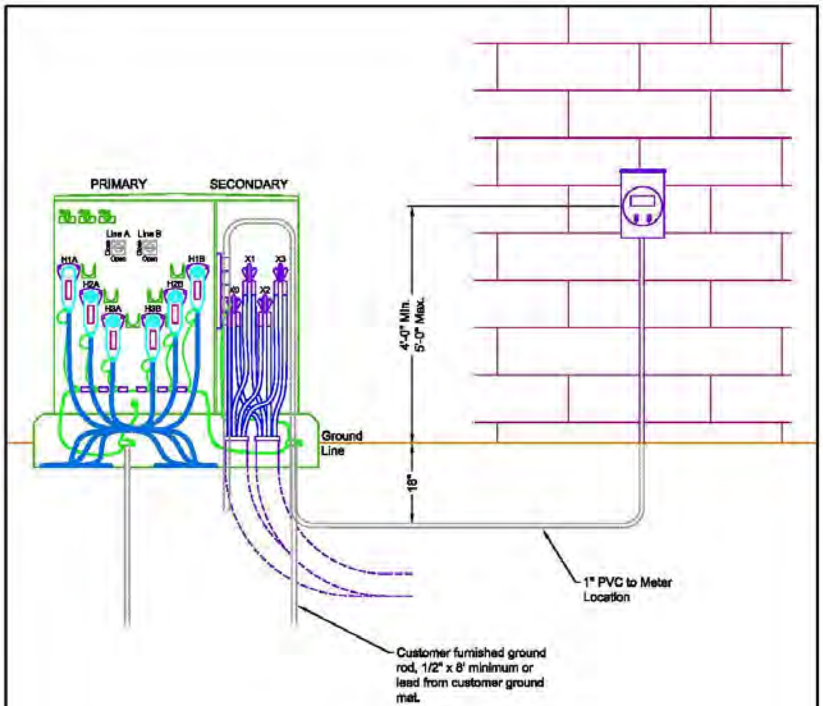
708. Fluorescent and Gaseous Tube Lighting
High power factor ballasts or transformers must be used for fluorescent, sodium vapor, neon or other gaseous tube lighting equipment. It is required that such equipment operate at a power factor of not less than 90% lagging.

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
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



NOTES:

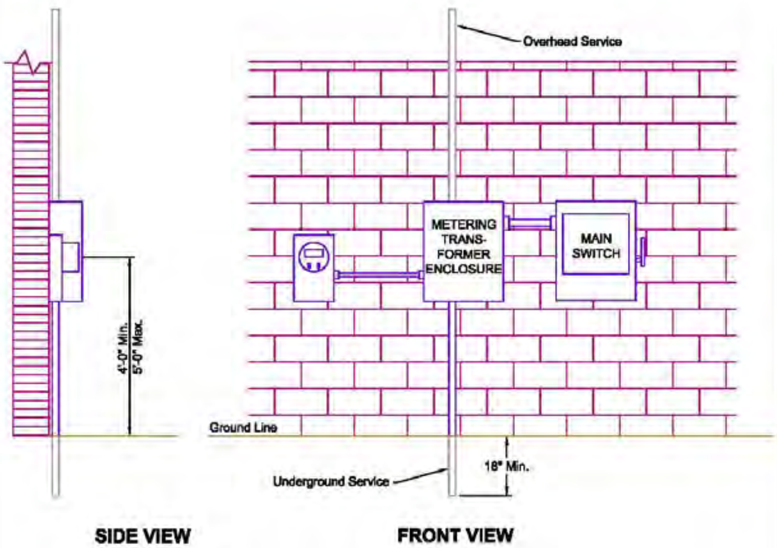
1. Meter socket shall not be mounted directly on the padmount transformer.
2. 1" PVC shall be used from meter socket to padmount transformer.
3. Customer shall furnish and install the meter socket or sockets and the 1" PVC conduit. 1" conduit shall be installed to meet wiring codes. Conduit should always be run into the secondary compartment of the padmount transformer, never into the primary compartment.

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

TRANSFORMER RATED METERING
PADMOUNT TRANSFORMER

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A
FIGURE NO: 2



NOTE:

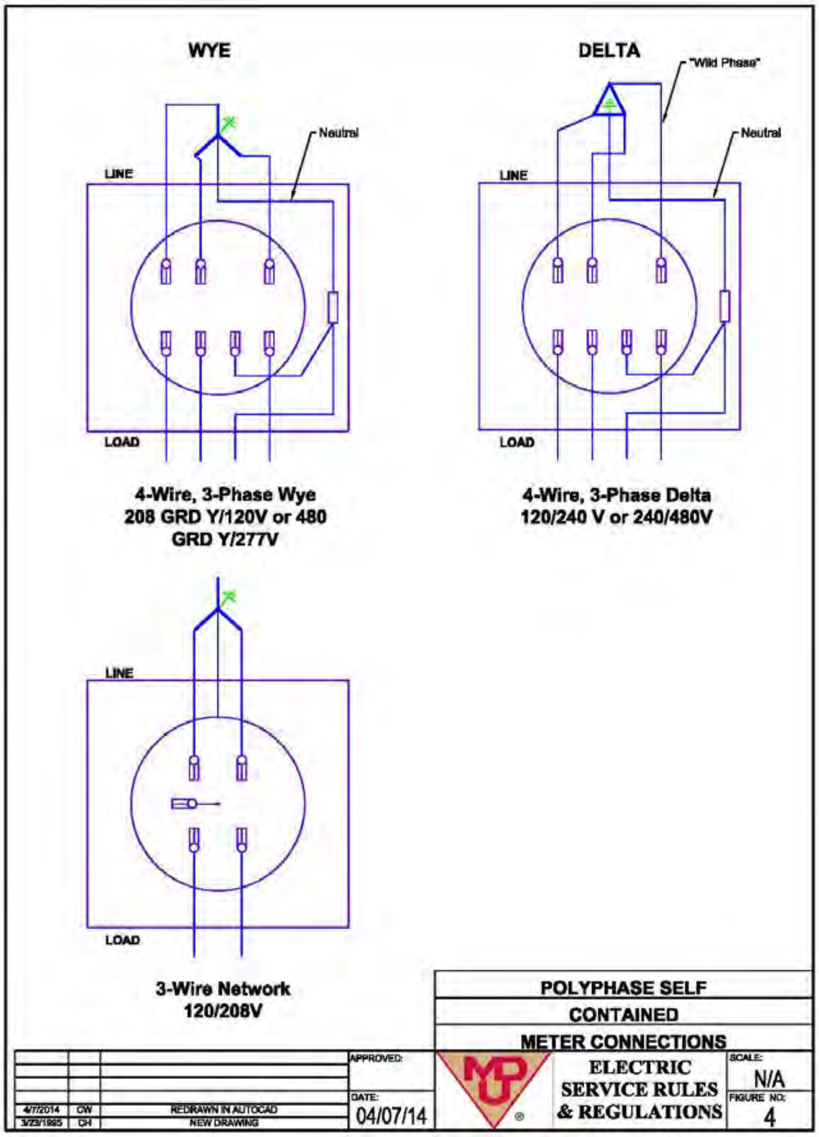
1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3.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

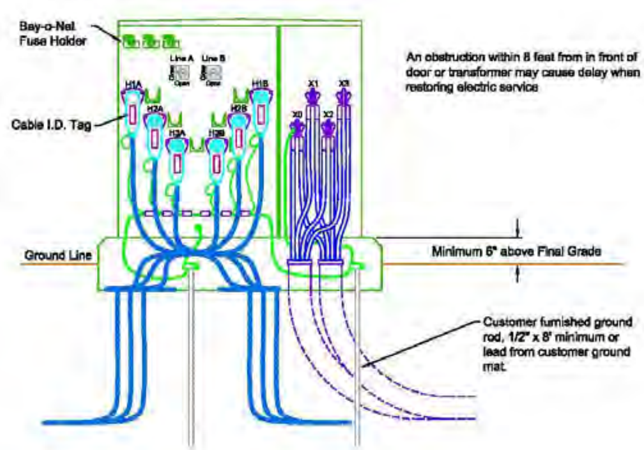
TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE

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
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
APPROVED:
DATE:
04/07/14
ELECTRIC
SERVICE RULES
& REGULATIONS
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.

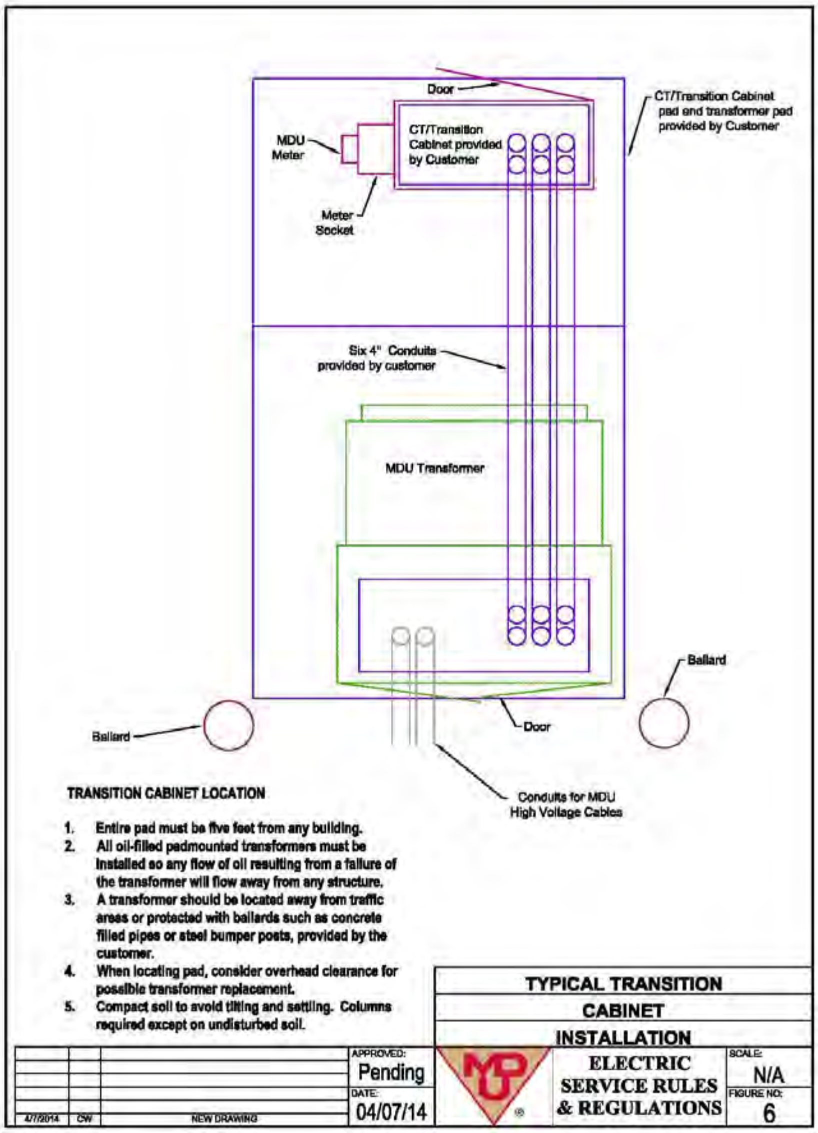
TRANSFORMER LOCATION

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	
1/31/2003	CH	NEW DRAWING	

APPROVED: Pending
DATE: 04/07/14
ELECTRIC SERVICE RULES & REGULATIONS
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

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 3.7 times the estimated annual revenue excluding fuel and purchased power (3.7 to 1 ratio).

2. If the estimated project construction cost is greater than 3.7 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 3.7 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) Residential Customers - If within a ten-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). A customer may receive a refund only if the customer paid for the initial extension or subsequent connection to the extension and at the time the refund is issued, the customer owns the residential structure to which the extension or subsequent connection to the extension was made. No refund shall be made by Company to residential customer(s) after a ten-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

2) Non-Residential Customers - 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). No refund shall be made by Company to non-residential customer(s) after a five-year period from which initial

service is established, nor shall refunds be made in excess of the amount contributed.

3) Developers of Subdivisions - Refunds 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. No refund shall be made by Company to a 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 Montana 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.

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

State of Montana
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 ± 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 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 ±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 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 two years rather than the entire vintage class.

SELECTIVE TESTING PLAN FOR WATTHOUR METERS Rate 131

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 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 two years rather than the entire vintage class.

Tariffs Reflecting Proposed Changes

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

State of Montana
Electric Rate Schedule

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Issued: ~~September 28, 2018~~November 4, 2022

By: ~~Tamie A. Aberle~~Travis R. Jacobson
Director – Regulatory Affairs

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~~Docket No. D2018.9.60~~

~~Effective with service rendered on and after September 1, 2019~~

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~~**COMMUNITIES SERVED**~~
~~*Designates District Office~~

Badlands Region

Antelope	*Glendive	Redstone
Bainville	Homestead	Reserve
Baker	Ismay	Rosebud
Brockton	Kinsey	Savage
Culbertson	Medicine Lake	Scobey
Fairview	*Miles City	Sidney
Fallon	Outlook	Terry
Flaxville	Plentywood	Whitetail
Forsyth	Plevna	Wibaux
Froid	Poplar	*Wolf Point

*Designates District Office

AVAILABILITY:

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

RATE:

Basic Service Charge:	$~~0.19~~0.25 per day
Energy Charge:	
October – May	~~6.520~~7.668¢ per Kwh
June – September	~~8.517~~9.665¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. Low-Income Discount: Customers qualifying for and receiving energy assistance through the Low Income Energy Assistance Program (LIEAP) administered by the State of Montana Department of Public Health and Human Services (DPHHS) shall obtain a discount from the amount billed under this rate schedule. The applicable discount, as set forth below, will be administered

based upon the percentage of poverty guidelines established by DPHHS and information supplied to the Company by DPHHS at the time the customer qualifies for LIEAP.

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

2. The foregoing schedule is subject to Rates 100-131 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 Montana~~
~~Electric Rate Schedule~~

~~Reserved for Future Use~~

~~Reserved for Future Use~~

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 arranged so that all service can be measured through one meter.

RATE:

Basic Service Charge:		$~~0.36~~0.47 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	~~6.384~~7.508¢ per Kwh
	June – September	~~9.639~~10.938¢ per Kwh
Off-Peak Energy:	~~5.905~~6.844¢ per Kwh for all energy not covered by the On-Peak rating period.	
Base Fuel and Purchased Power:		~~2.542~~2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

GENERAL TERMS AND CONDITIONS:

1. 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 of returning to the regular Residential Electric Service rate.

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

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

3. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

State of Montana
Electric Rate Schedule

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~~11th Revised~~ Original Sheet No. 10
~~Canceling 10th Revised Sheet No. 10~~

SMALL GENERAL ELECTRIC SERVICE Rate 20

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 Kilowatts or less 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:

Basic Service Charge:	$~~0.65~~0.90 per day
Primary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$~~12.00~~13.00 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$~~13.00~~14.00 per Kw
Energy Charge:	
October – May	~~3.764~~4.029¢ per Kwh
June – September	~~5.644~~5.909¢ per Kwh
Base Fuel and Purchased Power:	~~2.523~~2.714¢ per Kwh
Secondary Service:	
Demand Charge October – May:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$~~12.75~~13.75 per Kw
Demand Charge June – September:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$~~14.00~~15.00 per Kw

Energy Charge:	
October – May	~~3.864~~4.129¢ per Kwh
June – September	~~5.744~~6.009¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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. Customer 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. The 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. 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.

~~3~~4. The foregoing schedule is subject to Rates 100-131 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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~~Canceling 10th Revised Sheet No. 15~~

IRRIGATION POWER SERVICE Rate 25

AVAILABILITY:
For irrigation power service.

RATE:

Basic Service Charge:	$~~0.75~~1.00 per day
Demand Charge:	
October – May	$~~3.00~~4.00 per Kw
June – September	$~~5.00~~6.00 per Kw
Energy Charge:	~~2.624~~3.006¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-131 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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Bismarck, ND 58501

State of Montana
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 of 50 Kilowatts or less 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:	$~~31.89~~44.15 per month
Primary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$~~12.75~~13.81 per Kw
June – September	$~~15.74~~16.95 per Kw
On-Peak Energy:	
October – May	~~5.687~~5.954¢ per Kwh
June – September	~~6.973~~7.301¢ per Kwh
Off-Peak Energy:	~~3.464~~3.681¢ per Kwh
Base Fuel and Purchased Power:	~~2.523~~2.714¢ per Kwh
Secondary Service:	
On-Peak Demand Charge:	
First 10 Kw or less of billing demand:	No Charge
Over 10 Kw per month of billing demand:	
October – May	$~~13.06~~14.08 per Kw
June – September	$~~16.23~~17.39 per Kw

On-Peak Energy:	
October – May	~~5.657~~5.918¢ per Kwh
June – September	~~7.066~~7.392¢ per Kwh
Off-Peak Energy:	~~3.505~~3.712¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. Demands will be determined to the nearest one-tenth kilowatt.

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. 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. The 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. 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 of returning to the regular Small General Electric Service rate.

4. The foregoing schedule is subject to Rates 100-131 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 Montana
Electric Rate Schedule

LARGE GENERAL ELECTRIC SERVICE Rate 30

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand 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:	$~~230.00~~255.00 per month
Demand Charge:	
October – May	$~~11.10~~12.10 per Kw
June – September	$~~12.45~~13.45 per Kw
Energy Charge:	~~2.908~~2.855¢ per Kwh
Base Fuel and Purchased Power:	~~2.523~~2.714¢ per Kwh
Secondary Service:	
Basic Service Charge:	$100.00 per month
Demand Charge:	
October – May	$~~11.30~~12.30 per Kw
June – September	$~~12.65~~13.65 per Kw
Energy Charge:	~~2.936~~2.883¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 50 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. 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. The 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 100-131 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 demand metered general electric service exceeding 50 Kilowatts of billing demand 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:	$~~230.00~~255.00 per month
On-Peak Demand Charge:	
October – May	$ ~~8.50~~9.60 per Kw
June – September	$~~15.80~~16.90 per Kw
On-Peak Energy:	
October – May	~~4.768~~4.712¢ per Kwh
June – September	~~5.768~~5.712¢ per Kwh
Off-Peak Energy:	~~2.768~~2.712¢ per Kwh
Base Fuel and Purchased Power:	~~2.523~~2.714¢ per Kwh
Secondary Service:	
Basic Service Charge:	$100.00 per month
On-Peak Demand Charge:	
October – May	$ ~~9.50~~10.50 per Kw
June – September	$~~16.50~~17.50 per Kw

On-Peak Energy:

October – May	~~4.768~~4.712¢ per Kwh
June – September	~~5.768~~5.712¢ per Kwh

Off-Peak Energy: ~~2.768~~2.712¢ per Kwh

Base Fuel and Purchased Power: ~~2.542~~2.900¢ per Kwh

On-Peak is defined as 12 p.m. to 8 p.m. local time, Monday through Friday.

Off-Peak is defined as all hours not covered by the on-peak period.

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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. 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. 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 agrees to contract for service under the Optional Time-of-Day Large 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 Large General Electric Service rate or of returning to the regular Large General Electric Service rate.

3. The 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.

4. The foregoing schedule is subject to Rates 100-131 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:	$~~30.00~~55.00 per month
Primary Service:	
Demand Charge:	
October – May	$~~2.75~~3.00 per Kw
June – September	$~~12.45~~12.70 per Kw
Energy Charge:	~~2.433~~3.039¢ per Kwh
Base Fuel and Purchased Power:	~~2.523~~2.714¢ per Kwh
Secondary Service:	
Demand Charge:	
October – May	$~~3.25~~3.50 per Kw
June – September	$~~12.65~~12.90 per Kw
Energy Charge:	~~2.433~~3.039¢ per Kwh
Base Fuel and Purchased Power:	~~2.542~~2.900¢ 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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 100-131 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 Montana
Electric Rate Schedule

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~~11th Revised~~Original Sheet No. 23
~~Canceling 10th Revised Sheet No. 23~~

CONTRACT SERVICE Rate 35

AVAILABILITY:
For the Denbury Onshore LLC accounts designated in the Electric Service Agreement dated June 28, 2017.

RATE:

Basic Service Charge:	$~~250.00~~285.00 per month
Demand Charge:	
October – May	$ ~~8.50~~10.25 per Kw
June – September	$~~10.00~~11.75 per Kw
Energy Charge:	~~2.174~~2.691¢ per Kwh
Base Fuel and Purchased Power:	~~2.456~~2.785¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

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 50 Kw. Demands will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

Montana-Dakota reserves the right to require Denbury Onshore LLC 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 Denbury Onshore LLC 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:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by Montana-Dakota under the laws of the state.

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT:

The following sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment for Contact Service Rate 35. It specifies the procedure to be utilized to adjust the rates for electricity sold in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account as allocated to Contract Service Rate 35.

1. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:
   Unless otherwise ordered by the Commission, the effective date of the Fuel and Power Cost Tracking Adjustment and amortization of the Unreflected Fuel Cost Account shall be service rendered on and after January 1 each year.

2. FUEL AND POWER COST TRACKING ADJUSTMENT:
   a. The Fuel and Power Cost Tracking Adjustment shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base

fuel cost shall be ~~2.456~~2.785¢ per Kwh as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for Rate 35, and shall be the sum of the following estimated costs for the annual period the adjustment shall be in effect, as allocated to Montana and to Contract Service Rate 35, taking into account applicable line losses:
   1. The cost of fossil and other fuels and sand and reagents as recorded in Account Nos. 501, 502 and 547.
   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555.
   3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the year is the sum of 2(b) above divided by projected Contract Service Rate 35 sales volumes for the period the adjustment will be in effect.

d. The Annual Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 2(b) multiplied by ninety (90) percent.

3. UNREFLECTED FUEL COST ADJUSTMENT:
   Contract Service Rate 35 shall be subject to an Unreflected Fuel Cost Adjustment to be effective on January 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

4. UNREFLECTED FUEL COST ACCOUNT:
   a. Items to be included in the Unreflected Fuel Cost Account are:
      1. Amounts under recovered or over recovered for fuel and purchased power each month as calculated in accordance with Subsection 4(b).
      2. Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

   b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 4(a)(1) and (2) shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power.
      2. Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.
      3. The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in an Unreflected Fuel Cost Account for Contract Service Rate 35.
      4. Carrying charges or credits at a rate equal to the overall rate of return established in the most recent general rate case.

   c. Reduction of Amounts in the Unreflected Fuel Cost Account:
      1. The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 4) under Contract Service Rate 35. The Account shall be increased in the event the adjustment is a negative amount. The amount amortized shall be applied pro rata between the Unrecovered Fuel Cost Account and the interest balance.

5. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES: The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

6. TIME AND MANNER OF FILING:
   a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 6 identifying the amount of the adjustment.

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

7. EFFECTIVE ADJUSTMENT:

Base Fuel	~~2.456~~2.785¢
Fuel and Power Cost Adjustment	~~(0.495¢)~~
Total Adjustment per Kwh	~~1.961¢~~

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State of Montana
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.~~ $255.00 per month

Demand Charge:

October – May	$~~6.10~~8.60 per Kw
June – September	$~~7.45~~9.95 per Kw

Energy Charge: ~~2.908~~2.855¢ per Kwh

Base Fuel and Purchased Power: ~~2.523~~2.714¢ 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.

ADJUSTMENT CLAUSES:

Bills are subject to the following adjustments as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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.

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 Base Rate payments to the Company. The monthly Base Rate 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 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. Company will notify 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 used 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. 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 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:

For the lighting of public 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.

~~ENERGY~~ RATE:

Energy Charge: ~~7.173~~7.295¢ per Kwh computed according to the total rated capacity of the lamps in use.

Base Fuel and Purchased Power: ~~2.542~~2.900¢ per Kwh

FACILITIES CHARGE per unit per month:

Applicable to lighting facilities owned, installed, and maintained by the Company.

LED, Overhead Conductor, Distribution Pole	$4.00
LED, Overhead Conductor, Street Light Pole	$7.60
LED, Underground Conductor, Distribution Pole	$5.10
LED, Underground Conductors, Street Light Pole	$8.70
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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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,

PUBLIC LIGHTING SERVICE Rate 41

malicious mischief, or willful negligence the Company will charge the municipality for the cost of repair and replacement.

~~2. The energy rate charged to municipally-owned street lighting systems shall be the above tariffed rate less 0.500¢ per Kwh.~~

2~~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.

3~~4~~. When service is not metered, the energy usage shall be computed on an daily basis, utilizing the minimum service requirement of 4,000 hours annually, and billed monthly to the customer.

4~~5~~. The foregoing schedule is subject to Rates 100-131 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 Montana
Electric Rate Schedule

Volume No. ~~4~~5
~~11th Revised~~ Original Sheet No. 34
~~Canceling 10th Revised Sheet No. 34~~

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:

Basic Service Charge: $~~30.00~~40.00 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	$~~4.00~~4.50 per Kw
June – September	$~~6.00~~6.50 per Kw

Energy Charge: ~~3.211~~3.523¢ per Kwh

Base Fuel and Purchased Power: ~~2.542~~2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:

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

RATE:

Energy Charge: ~~11.695~~12.948¢ per Kwh computed according to the total rated capacity of the units in use.

Base Fuel and Purchased Power: ~~2.542~~2.900¢ per Kwh

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 as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56
- Fuel and Purchased Power Cost Tracking Adjustment Rate 58

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 poles(s) for yard light(s) at the customers 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 ~~and change the light bulbs~~ when notified by the customer or noticed by Company personnel ~~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 customer~~. In case of vandalism, malicious mischief, or willful negligence, the Company will charge the customer for the cost of repair and replacement.

2. When service is not metered, the bill shall be computed on ~~an annual~~a daily basis, utilizing the minimum service requirement of 4,000 hours annually, and ~~one-twelfth shall be payable each month~~billed monthly to customers. Christmas lighting will be billed for the months in service.

~~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.~~

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. The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

ELECTRIC LINE MOVING COST SCHEDULE Rate 53

APPLICABILITY:

This rate schedule sets forth the charges to be applied to recover the costs associated with the expense of moving poles or raising or cutting wires or cables to accommodate the relocation of a structure, as required by Montana Code Annoted (MCA) Section 69-4-602 and 69-4-603.

CHARGES:

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a house, building, derrick, other structure, or prefabricated structure that is intended to be moved from the place of fabrication, storage facility, or dealer's lot, determined in accordance with the rates set forth below must be paid by the mover.

The necessary and actual costs of raising or cutting wires or cables or moving poles to facilitate the movement of a structure, determined in accordance with the rates set forth below must be shared equally by the mover and the owner of the wires, cables, or poles if the structure is owned by a person for occupancy or use by that person.

RATE:

Refer to Cost Schedule for current rate information

GENERAL TERMS AND CONDITIONS:

1. Prepayment – The mover shall make a prepayment of a portion of the estimated total cost in advance of the move as follows:
    a. If the structure is moved through or out of the Company's service territory, 100% of the mover's share.

b. If the structure is delivered to a place within the Company's service territory, 50% of the mover's share.
c. The Company may waive the prepayment requirement or accept a bond or other financial instrument in lieu of payment.

ELECTRIC LINE MOVING COST SCHEDULE Rate 53

d. The mover shall pay the mover's share of all actual costs in excess of any prepayment within 30 days of the move.
e. If the prepayment made exceeds the mover's share of actual costs the Company shall refund the difference to the mover within 30 days of the move.

2. The foregoing schedule is subject to 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 Montana
Electric Rate Schedule

ELECTRIC UNIVERSAL SYSTEM BENEFITS CHARGE Rate 55

APPLICABILITY:

In all communities served for all retail electric service in order to recover the costs associated with Universal System Benefit Programs required by the Electric Utility Industry Restructuring and Customer Choice Act, Montana Code Ann. §§69-8-101.

RATE:

Large Customer Accounts(Defined Below):	.0900¢ per Kwh for all energy used.
All other accounts:	.1566¢ per Kwh for all energy used.

GENERAL TERMS AND CONDITIONS:

1. Large Customer Accounts are defined as any customer with monthly billing demands of 1,000 Kw or higher, determined by dividing the customer's previous calendar year's total billing demand by 12.

   a. Large Customer Accounts shall be charged an annual Universal System Benefits Charge(USBC) assessment equal to the lesser of $500,000 or the product of .09¢ per Kwh for all energy used.

   b. Large Customer Accounts shall receive a credit toward their annual USBC assessment for internal expenditures and activities that qualify as Universal System Benefit programs as determined by the Montana Department of Revenue.

   c. Large Customer Accounts with qualifying credits that exceed the customers annual USBC assessment shall be carried forward and credited to customer's future USBC assessments until the total amount of the qualifying credits have been credited to the customer's account.

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

Issued: ~~February 8, 2008~~November 4, 2022

By: ~~Donald R. Ball~~Travis R. Jacobson
~~Vice President~~ Director - Regulatory Affairs

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~~Docket No. D2007.7.79~~
~~Order No. 6846f~~

~~Effective with service rendered on and after May 1, 2008~~

ELECTRIC TAX TRACKING ADJUSTMENT Rate 56

1. **Applicability:**
This rate schedule sets forth the procedure to be used in calculating the Tax Tracking Adjustment in order to reflect: (a) changes in Montana-Dakota's Montana state and local taxes and fees, and (b) a true-up of taxes recovered to actual taxes paid. The tax adjustment shall be shown as a separate item on the bill.

2. **Effective Date:**
The Tax Tracking Adjustment shall be adjusted annually and ~~T~~the effective date of the Tax Tracking Adjustment shall be service rendered on and after ~~May 15, 2017 and shall be adjusted annually thereafter on~~ January 1 each year.

3. **Tax Tracking Adjustment:**
   a. The Tax Tracking Adjustment shall reflect changes in Montana-Dakota's Montana state and local taxes and fees as compared to the base levels approved in its most recent general rate case. The difference to be included in the Tax Tracking Adjustment shall be net of income taxes.

   b. Base Tax – A base tax amount shall be established and updated in general rate cases for each rate schedule:
      (1) The ratio of authorized Montana state and local taxes and fees, excluding tribal taxes, to the non-fuel revenues shall be determined.

      (2) The ratio is applied to the total basic service charge, energy charge, and demand charge revenues for each rate schedule to derive the base tax amount for each rate schedule.

   c. Rates excluding taxes
      (1) The authorized non-fuel revenue excluding base taxes (defined as base margin) is established by applying one minus the ratio derived in 3.b.(1) to the authorized non-fuel revenues by rate schedule.

      (2) The percentage of base taxes to base margin is derived to establish the baseline tax recovery amounts included within the basic service charge,

energy charge and demand charge by applying that percentage to each rate component of each rate schedule.

d. The Tax Tracking Adjustment shall have two components and be computed as follows:

(1) Rate Year Estimate- To recover changes in estimated tax expenses from the base tax level for the year in which the rates will apply (the "Rate Year"), actual tax expense for the prior year shall be used as a proxy for Rate Year taxes and compared to the tax expense projected to be recovered in the Rate Year. That difference (whether positive or negative), adjusted for income taxes, is the Rate Year estimate component. ~~For Rate Year 2017 only, the Rate Year Estimate will be charged only during the period May 15, 2017 to December 31, 2017.~~

(2) Annual True-Up- To true-up each year's tax expense recovered to the actual tax expense for that year, the actual tax expense for the year prior to the Rate Year is compared to the tax expense recovered in the same year. That difference (whether positive or negative), adjusted for income taxes, is the Annual True-Up component. ~~For Rate Year 2018 only, the true-up will be calculated using the difference between tax expense recovered and actual tax expense for the period May 15, 2017 to December 31, 2017. No Annual True-Up component applies to Rate Year 2017.~~

(3) The sum of amounts (positive or negative) in 3.d.(1) and 3.d.(2) above is divided by the base margin to derive the percent increase (decrease) in taxes.

(4) The base tax percentage determined in 3.c.(2) and the tax adjustment percentage determined in 3.d.(3) are added to calculate the total percent of taxes.

(5) The total percent of taxes is applied to the base margin, comprised of the basic service charge, energy charge, and demand charge billed to each customer, and shown separately on the customer bill.

4. Time and Manner of Filing:
A filing shall be made on or before November 30 of each year to modify the Tax Tracker Adjustment for the subsequent year. That filing shall be accompanied by the detailed computations which clearly show the derivation of the relevant amounts.

5. Tax Tracking Adjustment:

Base	~~8.5063~~11.8751%
Adjustment	~~1.6594~~0.0000%
Total tax	~~10.1657~~11.8751%

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

1. APPLICABILITY:
This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 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 tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:
Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs by month by source, with annual totals and;

b. Generation and purchases (Mwh) by month by supply source, with annual totals~~;~~.

~~c. Total Montana-Dakota sales by major customer class by month with annual totals and;~~

~~d. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals.~~

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be ~~2.523~~2.714¢ per Kwh for primary service and ~~2.542~~2.900¢ per Kwh for secondary service as established in the most recent general rate case.

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 Montana and to the primary and secondary customer classes:

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

2. The ~~net~~ cost of electric transmission delivery services linked to the utility's load serving obligation ~~purchases~~ and associated with participation in regional transmission organizations as recorded in Account Nos. 560, 561, 565 and 928 offset by corresponding revenues received from regional transmission organizations as recorded in Account No. 456. ~~costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account No. 555.~~

3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 4(c) multiplied by ninety (90) percent.

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

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

(1) Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power as specified in Subsection 4.

(2) Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.

(3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in the Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

(1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES:
The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

8. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

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

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

State of Montana
Electric Rate Schedule

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

9. FUEL AND POWER COST ADJUSTMENT:

	Primary	Secondary
Base Fuel	~~2.523~~2.714¢	~~2.542~~2.900¢
Fuel and Power Cost Adjustment	~~(0.215)~~	~~(0.288)~~
Total FPPA per Kwh	~~2.308¢~~	~~2.254¢~~

Issued: ~~September 16, 2022~~November 4, 2022

By: Travis R. Jacobson
Director - Regulatory Affairs

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~~Docket No. 2022.06.070~~ ~~Effective with service rendered on and after October 1, 2022~~

NET METERING SERVICE Rate 92

AVAILABILITY:

Available to any customer with a small generator facility whose capacity does not exceed 50 Kw that is located on the customer's premises and is intended primarily to offset part or all of the customer's own electrical requirements. The small generating facility, hereinafter referred to as eligible customer generator, must be interconnected and operated in parallel with the Company's existing distribution facilities.

APPLICABILITY:

Net Metering means measuring the difference between the electricity supplied by the Company and electricity generated by an eligible customer-generator that exceeds the customer's own use or is sold to Montana-Dakota.

RATE:

Basic Service Charge: The Basic Service Charge per the applicable standard service rate.

Demand Charge: The Demand Charge per the applicable standard service rate.

Energy Charge: If the energy supplied by the Company exceeds the customer generated energy, the energy charge per Kwh under the otherwise applicable standard service tariff shall be applied to the positive energy balance and charged to the customer.

If the energy supplied by the customer generator exceeds the amount of energy supplied by the Company, the net Kwh shall be credited to the customer's next monthly bill. The balance of the energy generated shall appear as a credit on the customer's account until the customer's consumption offsets the credit or the end of the designated 12-month billing period, which ever occurs first. At the end of the 12-month period any unused Kwh credit

accumulated during the previous 12-months will be granted to the Company with no compensation to the customer. The customer shall designate the start date of the 12-month billing period as January 1, April 1, July 1 or October 1.

GENERAL TERMS AND CONDITIONS:

1. INTERCONNECTION AGREEMENT:
   Prior to connecting a renewable energy system to operate in parallel with the utility, the eligible customer-generator must initiate and enter into an Interconnection Agreement with the Company in accordance with Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96.

2. INTERCONNECTION AND OPERATION:
   a. Upon completion of a signed interconnection agreement and the initiation of service, the customer shall operate its Small Generator Facility in parallel with Montana-Dakota's system and in accordance with the terms of the Interconnection Agreement, Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff and the Administrative Rules of Montana 38.5.84.
   b. There should only be one net metering system installed per each metered service located on the customer's premises. The net metering system must have an aggregate nameplate capacity per premise that does not exceed 50 Kw and be fueled by solar, wind, or hydropower.
   c. Neither customers, customer accounts or services, nor meters may be aggregated for purposes of net metering.

3. METERING:
   Montana-Dakota will provide a standard meter capable of registering the flow of electricity in two directions. Any additional costs necessary for the interconnection are the responsibility of the customer in accordance with

Rate 96 ¶ VIII.5 and as outlined in the Small Generator Facility Distribution Interconnection Agreement.

4. INTERRUPTION OF DELIVERIES:
   The Company may require the customer to interrupt or reduce deliveries of available energy when Company determines (a) such interruption is necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any Company-owned equipment or part of the Company's system, or (b) that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with any electrical code or standard. Whenever possible, Company will give the customer notice of the possibility that interruption or reduction of deliveries may be required.

5. TEMPORARY DISCONNECTION OF FACILITY:
   If at any time the Company determines that either (a) the customer's eligible generator, or its operation, may endanger Company personnel, or (b) the continued operation of the generator may endanger the integrity of the Company's electric system, the Company shall have the right to disconnect the generator from the Company's system. The Company will give the customer notice of such occurrence as soon as practical. The customer's eligible generator will remain disconnected until such time as the Company determines that all condition(s) are such that it is safe to reconnect.

   The Company is not obligated to pay for energy that would otherwise have been delivered to its system absent the occurrences described in this section.

6. The foregoing schedule is subject to Rates 101 through 131 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

AVAILABILITY:

To any qualifying cogeneration and small power production facility (QF), as defined under the Administrative Rules of the Montana Public Service Commission, for the purpose of generating electric energy in parallel with the Company's system, including ARM 38.5.1909 and any amendments or alternations to the rule. This schedule is applicable to a QF with a nameplate capacity of 3 MW or less who enters into a Power Purchase Agreement (Agreement) with the Company for a term not to exceed 15 years.

RATE:

Metering charge for single phase service	$6.50 per month
Metering charge for three phase service	$10.45 per month

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. Time Differentiated Energy Purchase Rate

	ON-PEAK	OFF-PEAK
2021	2.194¢ per Kwh	2.267¢ per Kwh
2022	2.072¢ per Kwh	2.139¢ per Kwh
2023	2.134¢ per Kwh	2.203¢ per Kwh
2024	2.198¢ per Kwh	2.269¢ per Kwh
2025	2.264¢ per Kwh	2.337¢ per Kwh
2026	2.332¢ per Kwh	2.407¢ per Kwh
2027	2.402¢ per Kwh	2.479¢ per Kwh
2028	2.474¢ per Kwh	2.553¢ per Kwh
2029	2.548¢ per Kwh	2.630¢ per Kwh
2030	2.624¢ per Kwh	2.709¢ per Kwh
2031	2.703¢ per Kwh	2.790¢ per Kwh
2032	2.784¢ per Kwh	2.874¢ per Kwh
2033	2.868¢ per Kwh	2.960¢ per Kwh
2034	2.954¢ per Kwh	3.049¢ per Kwh
2035	3.043¢ per Kwh	3.140¢ per Kwh
2036	3.134¢ per Kwh	3.234¢ per Kwh

Rating 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 Company's system operating characteristics.

2. Actual time differentiated system lambda determined for the month prior to the month in which energy is delivered by a QF.

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- Resource Adequacy of the MISO tariff.

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

Capacity payments will be paid in the subsequent billing period.

Monthly capacity payments 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 $10.004 per Kw applicable for the remainder of the term of the contract.

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 or large general service, etc.) that is currently on file with the Commission.

GENERAL TERMS AND CONDITIONS:

1. All purchases and sales of electric power between the Company and a QF of 3 MWs or less shall be accomplished according to the terms of a written contract and in accordance with the terms of this tariff.

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

3. The QF must apply for and enter into an Interconnection Agreement with the Company or the Transmission Service Provider prior to actual installation of equipment. A QF is responsible for all system Interconnection Facilities related costs and Network Upgrade costs. The QF shall be refunded its Network Upgrade related costs according to the terms and conditions of the applicable MISO tariff.

   Interconnection Facilities means the Company's or the Transmission Service Provider's Interconnection Facilities and the QF Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the QF and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   Network Upgrades are additions, modifications and upgrades to the Company's, Transmission Service Provider's or other affected parties' transmission system required at or beyond the point at which the QF interconnects with the transmission system to accommodate the interconnection with the QF to the Company's distribution or transmission system or Transmission Service Provider's transmission system.

   The rates and terms and conditions set forth herein are subject to the provisions of the "Interconnection Cost Amortization Option" set forth in Rate 95.

4. 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.

5. The QF 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.

6. The QF has the option of contracting for either the "Standard Payment Option" or "Net Billing Option Rate 94" for purposes of computing payments as stipulated in the written contract.

7. Sales by the QF to the Company do not include the transfer of the RECs associated with the energy produced. The RECs shall remain with the QF to utilize at their discretion.

8. All services provided by the Company under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

NET BILLING OPTION Rate 94

In addition to the parties' contract agreement, Company and Seller agree to the following net billing option:

1. Description: Under this option all purchases of energy from Seller by Company shall be considered on a net consumption basis, offsetting Company's purchases from Seller against its sales to Seller. If Company's sales to Seller are greater than its purchases from Seller in a billing period, Seller's net consumption shall be billed at the applicable retail rate and no further Avoided Cost Payments shall be made to Seller. If Company's purchases from Seller exceed its sales to Seller during a billing period, then the net purchases shall be purchased from Seller by Company pursuant to the applicable Avoided Cost Payments schedule. All purchases of capacity from Seller by Company will be considered on a net basis, offsetting Company's capacity purchases from Seller against its capacity sales to Seller on an hourly basis. Capacity payments will only be made if Company's energy purchases from Seller exceed its energy sales to Seller during a billing period.

2. Metering:
   (a) Energy: Company, at its expense, will install separate meters equipped with detents to measure its purchases from and sales to Seller.

   (b) Capacity: Company will make no Avoided Cost Payments for Capacity nor apply any offsets to its Demand charges for Capacity supplied by Seller unless such Capacity purchases by Company from Seller are separately metered. Such meters will be installed at Seller's expense.

3. Interconnection: Nothing herein shall relieve Seller from providing all necessary equipment for interconnection specified in the parties' contract.

4. Termination: If Seller fails to make any payments due to Company and Company is unable to recoup such overdue payments from Seller as an offset against Avoided Cost Payments for three consecutive months, the Net Billing Option shall automatically terminate and Company shall be entitled to its remedies under Montana Public Service Commission Rules (ARM 38.5.1401 et seq.).

5. Election: The election of the Net Billing Option is the sole prerogative of Seller. This option is merely an addendum to the parties' underlying standard contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' standard contract, the specific provision in this option controls.

INTERCONNECTION COST AMORTIZATION OPTION Rate 95

In addition to the parties' contract agreement, Company and Seller agree to the following interconnection cost amortization option:

1. Description: Under this option, Seller's obligation to reimburse Company for its cost of interconnection with Seller shall be made in monthly installments, such installments to include a finance charge as provided herein.

2. Finance Charge: Company's Cost of Interconnection shall be deemed to be the principal amount due and owing Company by Seller. The term of the loan shall be deemed to be the class life used by the Company for depreciating the special facilities required for interconnection or the length of the parties' contract, whichever is shorter. Seller shall repay the principal to Company in equal monthly installments over the term of the loan. Seller shall pay to Company each month interest on the unpaid balance computed, on an annual basis, to be equal to the incremental cost of capital to Company as of the date of the execution of this agreement. The incremental cost of capital to Company shall consist of the last cost of equity capital authorized by the Montana Public Service Commission, the current cost of new debt issues rate similarly to the bonds issued by Company, and the last cost of preferred stock experienced by Company.

3. Mortgage Requirement: Seller shall execute a first mortgage upon the Seller's property in favor of Company securing to Company full payment of all amounts due Company under this financing arrangement. In the event of a prior mortgage commitment, Seller shall secure for Company an adequate subordination agreement placing the mortgage required herein in a first position.

4. Nonpayment by Seller: In the event of nonpayment by Seller of any monthly installment due Company under this financing arrangement, Company may:
   (a) Offset the late payment against any amount due Seller from Company and thereafter deduct from each month's payments due Seller from Company an amount sufficient to cover the next month's installment of principal and interest due Company under this financing arrangement.

   (b) In the event the nonpayment exists for three consecutive months, declare the entire principal amount due and owing, together with any interest accrued thereon, declare the Seller in default, and exercise its rights under the parties' mortgage, and cease interconnection with Seller as a qualifying facility.

5. Necessary Documents: Seller shall execute all documents deemed necessary by Company to perfect a secured load transaction including, but not limited to, a note, mortgage, and Truth in Lending disclosure statement. Upon satisfaction of all of Seller's obligations under this financing arrangement, Company shall promptly release its mortgage interest in the property of the qualifying facility.

6. Election: The election of the Interconnection Cost Amortization Option shall be the sole prerogative of Seller. Seller's election shall be manifested by the parties' separate execution of this option. This option is merely an addendum to the parties' contract which binds the parties in all respects. In case of a conflict between a specific provision in this option and the parties' contract, the specific provision in this option controls.

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

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I. PURPOSE and APPLICABILITY:

This tariff is intended to provide the interconnection rules and procedures for any distribution customer of Montana-Dakota Utilities Co. (Montana-Dakota) located in the State of Montana proposing to install and interconnect a small generator facility to Montana-Dakota Electric Distribution System (EDS). The Small Generator Facility's nameplate capacity must be less than or equal to 10 MW and satisfy the following criteria:

1. The proposed small generator facility must be located on a utility customer's premise.
2. The customer installing the small generator facility must be in good standing with the Company.
3. The proposed small generator facility's point of interconnection may not be on a transmission line.
4. The power produced from the small generation facility must be contained on the Company's EDS and not flow onto Montana-Dakota's Electric Transmission System (ETS).
5. The power produced by the small generation facility must be intended to be utilized by the customer or sold to Montana-Dakota.

Generators that are proposed and designed for interconnection to the Company's ETS (interconnections to voltages above 25KV) or to deliver power to the Company's ETS are not covered under this scope of this tariff.

II. DEFINITIONS:

The following terms used in this tariff have the following meanings, except where the context clearly indicates otherwise:

APPLICANT - A person or entity that has filed an application to interconnect a customer generator to Montana-Dakota's Electric Distribution System (EDS). An applicant may include a third party who owns and operates a small generator facility under agreement with a customer or leases a small generator facility to a

customer.

COMMISSION - Public Service Commission of the State of Montana

CUSTOMER - Any entity connected to the utility system for the purpose of receiving electric power from the Company

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

CUSTOMER-GENERATOR - A customer that generates electricity, typically on the customer's side of the meter.

ELECTRIC DISTRIBUTION SYSTEM (EDS) –
1. The infrastructure constructed, maintained, and under the jurisdiction of Montana Dakota Utilities Co.
2. Electric Distribution System has the same meaning as the term Area EPS, as defined in 3.1.6.1 of the IEEE Standard 1547-2003.

ELECTRIC DISTRIBUTION COMPANY (EDC) – An electric utility that distributes electricity to end users within the State of Montana and is subject to regulation by the Commission.

ELECTRIC TRANSMISSION SYSTEM (ETS) – Montana-Dakota's Electric System that operates at voltages above 25KV are defined as transmission for the purpose of this rate schedule.

EXPORT - Power flows past the point of interconnection onto the EDS.

GOOD STANDING - A customer's account is not in arrears.

IEEE - Institute of Electrical and Electronics Engineers.

IEEE STANDARDS - The standards published by the Institute of Electrical and Electronics Engineers.

INTERCONNECT - To connect a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION - The result of connecting a utility customer's generator to Montana-Dakota's EDS.

INTERCONNECTION CUSTOMER - An applicant that has entered into an interconnection agreement with Montana-Dakota to interconnect a small generator facility and has interconnected that small generator facility to Montana-Dakota's EDS.

INTERCONNECTION EQUIPMENT – A group of components or an integrated system provided by the interconnection customer to connect a small generator facility to Montana-Dakota's EDS, including all interface equipment such as switchgear, protective devices, inverters, or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

INTERCONNECTION FACILITIES – The facilities and equipment required by Montana-Dakota to accommodate the interconnection of a small generator facility to Montana-Dakota's EDS and used exclusively to interconnect a specific small generator facility. Interconnection facilities do not include system upgrades that may benefit Montana-Dakota, other customers, other interconnection customers, or an owner of an affected system.

LINE SECTION - The portion of a radial distribution circuit to which an applicant seeks to interconnect and is bounded by sectionalizing devices or is located at the end of a distribution line.

NAMEPLATE CAPACITY - The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer and is usually indicated on a nameplate physically attached to the power production equipment.

NATIONALLY RECOGNIZED TESTING LABORATORY (NRTL) - A testing laboratory that is recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards.

NON-CONTINOUS PARALLEL GENERATOR – A generator that is designed to parallel the EDS for a short time period during a transfer of load for periods typically less than two minutes. This includes High Speed Transfer Switch Interconnections, Closed Transfer Systems, or Hot Transfer Standby Generator designs. The application process for this type of request will require the same process as a Continuous Parallel Generator. Some interconnection requirements may be relaxed, and an Interconnection Agreement may not be required, as determined on a case by case basis.

RADIAL DISTRIBUTION CIRCUIT - A circuit configuration in which independent feeders branch out radially from a common source of supply. In a radial distribution system, power flows in one direction from the company substation feeder to the load.

SMALL GENERATOR FACILITY - An energy resource(s) for the production and/or storage of electricity on the utility customer's premises that have an aggregate nameplate capacity that is less than or equal to 10 MW.

WITNESS TEST – A test performed jointly with Montana-Dakota to verify basic functionality of the small generator equipment and that the installation operates within acceptable limits of operation and does not interfere with the safety and operation of the EDS.

III. REQUEST FOR INTERCONNECTION:

1. INTERCONNECTION REQUEST:
   An applicant wanting to interconnect a small generator facility to the Company's EDS shall submit a Small Generator Facility Distribution Interconnection Application Form to Montana-Dakota.

   The applicant must determine, prior to the submission of an application, the Interconnection Level the project will be submitted under. A preliminary consultation with Montana-Dakota personnel is recommended to help simplify the process prior to submitting an application form.

2. QUEUE POSITION:
   Upon the receipt of an interconnection application request, Montana-Dakota shall assign a queue number in order to establish precedent with other existing and future interconnection requests on the same distribution circuit. The queue position of the interconnection request shall be used to determine the potential adverse system impacts of the small generator facility based on the relevant screening due to the nature of where a project is listed within the queue on a particular circuit. This will be communicated on the request acknowledgement form sent back to the applicant after the receipt of an application.

3. AGGREGATION OF MULTIPLE GENERATORS –
   a. An interconnection request for a small generator facility that includes multiple energy production devices at the common site where the applicant seeks a single point of interconnection shall be evaluated on the basis of the total aggregate nameplate capacity of the multiple devices.

   b. An interconnection request for an increase in the capacity for an existing small generator facility shall be evaluated using the new total aggregate capacity of the generators at the interconnection site.

4. FEE SCHEDULE:
Interconnection applications must include a non-refundable application fee for Level 1 and 2 interconnection requests or a refundable deposit for Level 3 and 4 interconnection requests. The amount of the fee is dependent on the review level procedures of the interconnection request. All fees or deposits for processing such request must be paid prior to acceptance of the interconnection request by the Company.

Level 1 Application Fee -	$ 50.00
Level 2 Application Fee -	$200.00
Level 3 Application Deposit -	$500.00
Level 4 Application Deposit -	$500.00

Interconnection Review Levels 1, 2, 3, and 4 are defined in Section III.7 of this tariff.

5. MODIFICATION OF APPROVED APPLICATION:
When an interconnection request is deemed complete between Montana-Dakota and an applicant, any modification or change to the completed interconnection not agreed to by Montana-Dakota in writing shall require the submission of a new interconnection application request.

6. CERTIFIED EQUIPMENT:
Interconnection application requests may be eligible for review procedures as outlined below in this tariff if the small generator facility uses certified interconnection equipment.
   a. Interconnection equipment shall be deemed certified upon the establishment of all the following:
      i. The interconnection equipment has been labeled and is publicly listed by a National Recognized Testing Lab (NRTL) at the time of the application.
      ii. The equipment must have certification testing results available from the manufacturer or NRTL upon request of the Company.

iii. The applicant must verify and provide information that the certified interconnection equipment is compatible with the generator and that the planned use of the certified interconnection equipment falls within the labeled and certified use and limits listed by the manufacturer.

iv. The interconnection equipment must be evaluated by a NRTL in accordance with the following codes:
1. IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems using the testing protocol IEEE 1547.1-2005 Standard testing procedures to establish conformity.
2. UL 1741 Standard Inverters, Converters, and Controllers for Use in Independent Power Systems.

7. INTERCONNECTION REVIEW LEVELS:
Interconnection application requests shall be reviewed using one of the following four procedures, based on size, complexity, and characteristics of the project:

a. Level 1 – Small Generator Facility – Certified Inverter Connected up to 50 KW: applicable to proposed customer generation interconnections where the generator size is 50 KW or less and the generated power is to be interconnected to the radial EDS utilizing Certified Inverter Equipment.

b. Level 2 – Small Generator Facility – Certified Equipment Connected up to 2 MW: applicable to proposed customer generation interconnections where the generator size is 2 MW or less and the generated power is to be connected to the radial EDS utilizing Certified Inverter Equipment.

Interconnection requests previously submitted under Level 1 but not approved under Level 1 may be reviewed as a Level 2 request under a new interconnection request for consideration.

c. Level 3 – Small Generator Facility – No Power Export – Up to 10 MW: applicable to proposed customer generation interconnections where the size

of the equipment is less than 10 MW and the generated power is planned for customer load with no power exported to the Company's EDS.

Interconnection requests previously submitted under Level 2 but not approved under Level 2 may be reviewed as a Level 3 request under a new interconnection request for consideration.

d. Level 4 – Small Generator Facility – Up to 10 MW: applicable to proposed customer generation interconnections where the size of the generation is less than 10 MW and the interconnection request does not meet the criteria for review under Levels 1, 2, or 3, or was not approved under Interconnection requests previously submitted for review under Levels 1, 2, or 3.

IV. LEVEL 1 REVIEW PROCEDURES:

An application interconnection request submitted under Level 1 shall be subject to the following review procedures:

1. The Level 1 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and shall indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:

a. Verify that the Interconnection Inverter Equipment Certification is valid and proper.
b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
    i. 15% of the peak load on the line section
    ii. The annual minimum load for the line section
c. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
d. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
e. The proposed small generator facility shall not exceed the capacity of the existing electrical service.
f. The Level 1 application cannot require any construction modifications to the Company's EDS

4. The Company shall, within 15 business days of an interconnection application being deemed complete, provide verification that the small generator facility equipment can be interconnected safely and reliably using Level 1 screens.

5. Within 5 business days of an approved Level 1 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
    a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
    b. The Witness Test has been performed and successfully completed.

7. If the Level 1 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 1 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 2, Level 3, or Level 4 review. The line section queue position assigned to the Level 1 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

V. LEVEL 2 REVIEW PROCEDURES:

An application interconnection request submitted under Level 2 shall be subject to the following review procedures:

1. The Level 2 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the potential for adverse system impacts using the following screens which must be satisfied:
   a. Verify that the Interconnection Inverter/Equipment Certification is valid and proper.
   b. Evaluate that the total aggregate generation, including the proposed application, does not exceed the following limits on the radial primary distribution circuit:
      i. 15% of the peak load on the line section
      ii. The annual minimum load for the line section

c. The proposed small generator facility, in total with other generation on the distribution circuit, must not contribute more than 10% to the maximum fault current at the point on the primary line nearest the point of interconnection.
d. The proposed small generator facility, in total with other generation on the distribution circuit, must not cause any distribution protective devices and equipment, or other customer equipment on the EDS to be exposed to fault currents exceeding 90% of the short circuit interrupting capability including X/R effects.
e. The proposed small generator facility, in total with other generation interconnected to the primary distribution side of a substation transformer feeding the circuit, may not exceed 10 MW in an area where there are known transient stability limitations to generating units located in the general electrical vicinity.
f. When a three phase three wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected phase-to-phase.
g. When a three phase four wire primary EDS is to be used to connect a proposed small generator facility, the generator will be connected line-to-neutral and shall be effectively grounded.
h. The proposed small generator facility must not exceed 20KVA of total generation on a shared neutral secondary system.
i. The proposed small generator facility must not exceed 20% of the nameplate rating of a transformer when connected 120 volts at a 120/240 volt single phase service.
j. The proposed small generator facility must not exceed the capacity of the existing service.
k. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company shall, within 20 business days of an interconnection application being deemed complete:
   a. Evaluate the request using the Level 2 review criteria

b. Review the applicant's analysis, if provided by the applicant, using the same criteria, and
c. Provide the applicant the Company's evaluation, including a comparison of the results of its own analysis with those included with the application.

5. Within 5 days of an approved, or conditionally approved Level 2 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. For approved requests, the Interconnection Agreement shall be signed and returned to Montana-Dakota within 30 business days of receipt of the letter or the interconnection request shall be deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   b. The Witness Test has been performed and successfully completed.

7. A conditionally approved interconnection application is an interconnection request that may be approved under Level 2 criteria with minor modifications to the Company's EDS, however the application has failed one or more of the evaluation elements listed previously. The Company will provide the applicant with a letter that includes an Interconnection Agreement and a listing of the milestones needed to be completed for the facility to be connected to the Company's EDS.
   a. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions being completed:
      i. All milestones agreed to the in the Interconnection Agreement are satisfied.
      ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
      iii. A Witness Test has been performed and successfully completed.

8. If the Level 2 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 2 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 3 or Level 4 review. The line section queue position assigned to the Level 2 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VI. LEVEL 3 REVIEW PROCEDURES:

An application interconnection request submitted under Level 3 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. Once the Interconnection Application is deemed complete, the Company shall evaluate the interconnection request using the following criteria:
   a. The total of the nameplate capacity of all generators on the circuit, including the proposed small generating facility, is 10 MW of less.
   b. The small generator will use reverse power relays or other protection that prevent power flow onto the EDS.
   c. The small generator facility is not served by a shared transformer.
   d. The construction of facilities by Montana-Dakota is not required to accommodate the proposed small generator facility.

4. The Company will evaluate the application and provide a response to the Applicant within 20 business days of a completed application form.

5. Within 5 days of an approved Level 3 application, Montana-Dakota shall provide a letter that includes an Interconnection Agreement. The Interconnection Agreement shall be signed and returned by the interconnection applicant within 30 business days from the receipt of the response or deemed withdrawn from the process.

6. The Interconnection Agreement will be approved by Montana-Dakota subject to the following conditions:
   a. All milestones agreed in the Interconnection Agreement are satisfied.
   b. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   c. The Witness Test has been performed and successfully completed.

7. If the Level 3 application is denied, Montana-Dakota shall provide a written response that includes the reasons for the denial of the Level 3 application request. The interconnection applicant may, as an option, choose to resubmit an interconnection application request for a Level 4 review. The line section queue position assigned to the Level 3 interconnection request shall be retained provided the request is made within 15 business days after notification that the current interconnection request has not been approved.

VII. LEVEL 4 REVIEW PROCEDURES:

An application interconnection request submitted under Level 4 shall be subject to the following review procedures:

1. The Level 3 & 4 Interconnection Request Application form shall be completed by the Applicant and submitted to Montana-Dakota. The application request shall include the Equipment Certification information, a Circuit Diagram of the proposed installation, and the application fee outlined in Section III.4.

2. Montana-Dakota will send an Interconnection Request Acknowledgement form back to the applicant within 10 business days. This acknowledgement will verify that the application has been received by the Company and indicate if the application is complete or if additional information is needed to complete the interconnection application.

3. A Level 4 application that is deemed incomplete shall have 10 business days to provide the data necessary to complete the interconnection request or the application will be deemed withdrawn from the process.

4. Once the Interconnection Application is deemed complete, the Company shall use the following metrics in performing a Level 4 review:
   a. With an agreement between the parties, the scoping meeting, interconnection feasibility study, interconnection impact study, or interconnection facilities study provided for in a Level 4 review may be waived.

   b. If agreed to by the parties, a scoping meeting will be held within 10 business days of the notification to the applicant that the interconnection application is complete, or the applicant has requested that its interconnection request proceed after failing the requirements of a Level 2 or Level 3 review.

   c. The scoping meeting will provide what is needed to proceed with a feasibility study and any further analysis of the proposed generator interconnection request. Any previous study results or other pertinent information will also be reviewed at the scoping meeting to determine the need for additional studies.

   d. An Interconnection Feasibility Study may be performed to determine if the project is feasible to interconnect with Montana-Dakota's EDS.

      If the parties agree that an Interconnection Feasibility Study shall be performed, the Company shall provide to the applicant, no later than 5

business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Feasibility Study shall include any of the following analyses necessary for the purpose of identifying any potential adverse system impacts on the EDS:

i. Initial identification of circuit breaker short circuit limits exceeded.
ii. Initial identification of any thermal overload issues
iii. Initial identification of any voltage limit issues
iv. Initial review of any grounding requirement and system protection concerns
v. A non-binding rough estimate of the costs of facilities required to interconnect the proposed generator to the EDS.

e. An Interconnection System Impact Study may be performed to review the system impacts of the proposed small generator on Montana-Dakota's EDS.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study is not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection System Impact Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

An Interconnection System Impact Study shall evaluate the impact of a proposed small generator on the Company's EDS on both the reliability and safety issues related to the proposed generator. Consideration of any studies that an applicant has provided will be reviewed and analyzed. The impact study shall include any necessary elements from among the following:

i. A load flow study
ii. Identification of the affected systems
iii. An analysis of equipment interrupting ratings
iv. A protection coordination study

v. Voltage drop and flicker studies
vi. Grounding reviews
vii. System operations impacts
viii. A short circuit analysis
ix. A stability analysis

f. An Interconnection Facilities Study shall be performed to estimate the cost of the equipment, engineering, procurement, and construction work, including overheads, needed to implement the conclusions of the Interconnection Feasibility Study and/or the Interconnection System Impact Study to interconnect the proposed small generator facility.

If the parties agree at the scoping meeting that an Interconnection Feasibility Study and an Interconnection System Impact Study are not required, Montana-Dakota shall provide to the applicant, no later than 5 business days after the scoping meeting, an Interconnection Facilities Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

The Interconnection Facilities Study shall identify the following:

i. The electrical switching configuration of the equipment, including transformer, switchgear, meters, and other station equipment.
ii. The nature and estimated cost of the Company's EDS changes required to interconnect the proposed small generator facility.
iii. An estimate of the time required to complete the construction and installation of the required facilities on the EDS.

g. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection can be made to the EDS, the Company will send a response letter to the applicant with an Interconnection Agreement for Small Distribution Generator Facility, including the requirement details associated with the proposed installation.

h. When the Company has determined, as a result of the studies conducted under a Level 4 review, that the proposed small generator interconnection cannot be made to the EDS, the Company will send a response letter to the applicant indicating the reasons for the denial of the application.

i. The applicant will have 30 business days after the receipt of an interconnection agreement to sign and return the agreement. When an applicant does not sign and return the application within 30 business days, the interconnection request shall be deemed withdrawn.

j. The interconnection agreement will be final only when:
   i. The milestones agreed to in the Interconnection Agreement for Small Distribution Generator Facility are satisfied.
   ii. The small generator facility has been approved by local, state, or municipal electric code authority that has jurisdiction over the installation.
   iii. The Witness Test has been performed and successfully completed.

VIII. GENERAL INTERCONNECTION PROVISIONS:

1. APPLICANT'S RESPONSIBILITY:
   a. The interconnection applicant is responsible for the construction of all generator facilities and the securing of any necessary approvals or permits from local, state, and federal authorities.

   b. The costs associated with the interconnection application and agreement are the responsibility of the interconnection applicant. This includes any application fees, the cost of various studies required, and any construction of facilities on the Electric Distribution System needed to accommodate a proposed small generator facility. The Company will not charge the applicant for the required Witness Test.

2. Existing capacity or construction of capacity by the Company on its EDS is not required to accommodate small generator facilities.

3. Interconnection facilities approved and installed under this and all other schedules are governed by the rules and regulations approved by the Montana Public Service Commission.

4. DISCONNECTION DEVICE:
   The proposed interconnection design of a Small Generator Facility must include a disconnect device installed, owned, and maintained by the customer to be used by the Company in the event of system operation maintenance or an emergency event. The disconnect device shall be capable of interrupting and isolating the small generation facility equipment from the Company's EDS. This device must allow for a visible break, must have the ability to be locked open, and must be accessible to the Company at all times for use. The location shall be within ten (10) feet of the metered service point unless special permission is granted by Montana-Dakota. The disconnection device shall be documented on the Interconnection Agreement.

5. METERING:
   Changes to or the addition of metering equipment to properly account for the generation and use of power at the interconnection site will be communicated by the Company in the application process. The customer will be responsible for the installation, costs, and maintenance of any load wiring, meter sockets, cabinets, etc. required for the accommodation of meters, instrument transformers, test switches, or other meter devices provided by and maintained by the Company. The additional or required metering changes shall be documented on the Interconnection Agreement.

6. TECHNICAL STANDARDS:
   Unless otherwise noted in this tariff, the technical standard to be used in evaluating all interconnection requests shall be the IEEE Standard 1547-2003 version.

7. WITNESS TEST:
   A witness test shall be required as part of the installation and approval of any proposed interconnection to the Company's EDS. This test is required to assure the small generator facility is operating within the characteristics of the equipment as proposed and certified along with an assurance that no operational interference is affecting any other customer's service on the Company's EDS. The applicant shall give the Company a 10-day notice to schedule this Witness Test of the small generator facility. This test may be performed at the commissioning startup of the proposed facility and a successful test is required to gain final approval of the interconnection agreement.

   The Witness Test at a minimum shall require:
   a. Verification of the Equipment proposed and declared on the Application Request.
   b. Verification of the location and access of the Disconnection Device.
   c. A Power Recording Device installation at the interconnection point to record a period of time the small generator facility is operating in parallel to the EDS.
   d. Verify that a loss in EDS voltage to the system allows for proper interruption of the generation voltage to the EDS. (Islanding Test)
   e. Any other test stipulated in the Interconnection Agreement.

   If the witness test is not acceptable, the Company shall send a written report to the applicant within 5 business days of the end of the witness test period. The applicant shall be granted 30 business days to address and resolve any deficiencies. If the applicant fails to address and resolve the deficiencies to the satisfaction of the Company, the interconnection request will be deemed withdrawn.

8. INSPECTION AND TESTING OF FACILITY:
   a. Future testing of an approved facility may be performed under the following circumstances:
      i. An annual test for Level 2 and Level 3 approved facilities

ii. Mutually agreed upon intervals for Level 4 approved facilities and any necessary testing specified by the manufacturer.

b. The Company shall have the right to inspect a customer generator facility before and after the interconnection approval is granted. This right to inspection is to be performed at reasonable hours and with reasonable prior notice provided to the customer.

9. MONITORING OF INTERCONNECTION EQUIPMENT:
The Company may require monitoring or control of a small generator facility if the nameplate capacity rating of the small generator facility interconnecting to the EDS, or the aggregate nameplate capacity of all small generator facilities on the line section in combination with the proposed small generator facility interconnecting to the EDS, is greater than 15% of the line section annual peak load as most recently measured at the substation or exceeds the annual minimum load of the line section.

10. DISCONNECTION OF SERVICE:
    a. The Company shall have the right to disconnect the customer generator facility at any time during an emergency on the EDS.
    b. If the Company discovers that the customer generator is not in compliance with the requirements of IEEE Standard 1547-2003, and the noncompliance adversely affects the safety or reliability of the EDS, the Company may require the disconnection of the customer generator facility until it complies. The Company will provide the customer with a written report of the details of how the customer generator facility is not complying with IEEE 1547-2003 or the Administrative Rules of the State of Montana (Small Generator Interconnections).
    c. The Company shall have the right to disconnect unauthorized small generator interconnections to the Company EDS upon discovery.

11. DISPUTE RESOLUTION:
    Either the Company or Customer Generator shall attempt to resolve all disputes regarding a small generator facility interconnection promptly, equitably, and in a good faith manner.

    When a dispute cannot be resolved, a party may seek immediate resolution through complaint procedures available through the Montana Public Service Commission.

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 1)

APPLICATION SCOPE:

LEVEL 1 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 50 KW in size utilizing inverter based certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96).

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Small Generator Facility Information

INVERTER

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

GENERATOR

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐ Turbine ☐

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐ Fuel Oil ☐

Generator Comments ______

Total System Design Capacity: ______ (KW) ______ (KVA)

SITE Information

This application is requested for: ☐ A New Small Generator to be located on an Existing Service.
☐ A New Small Generator to located at a New Service.
☐ A Change to an Existing Small Generator Location.

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Estimated Commissioning Date:

Interconnection Address/Location:

MDU Premise/Account (MDU USE):

Note: The Required Disconnect Switch must be able to be locked open and shall be located within 10 (Ten) feet of the meter location unless special permission is granted by the company.

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach a One-Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), and Disconnect Switch.

☐ - Completed Net Metering Application Addendum "A"

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $50.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Issued: ~~June 28, 2018~~November 4, 2022 **By:** ~~Tamie A. Aberle~~Travis R. Jacobson
Director – Regulatory Affairs

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~~Docket No. D2018.6.44~~ ~~Effective with service rendered on and after July 1, 2019~~

Small Generator Facility Distribution Interconnection
Level 1 Interconnection Request Application Form

Title: ______________________ Date: ______________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate: YES☐ NO ☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Level 2)

APPLICATION SCOPE:

LEVEL 2 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 2 MW in size and must utilize certified interconnection equipment (as defined in Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96). Also, Interconnections that were reviewed under Level 1 review procedures but not approved, can be re-submitted under a new Level 2 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

SITE INFORMATION

This application is requested for: ☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location:

MDU Premise/Account (MDU USE ONLY):

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: ______ Amps Voltage: ______ Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date:

Small Generator Facility General Information

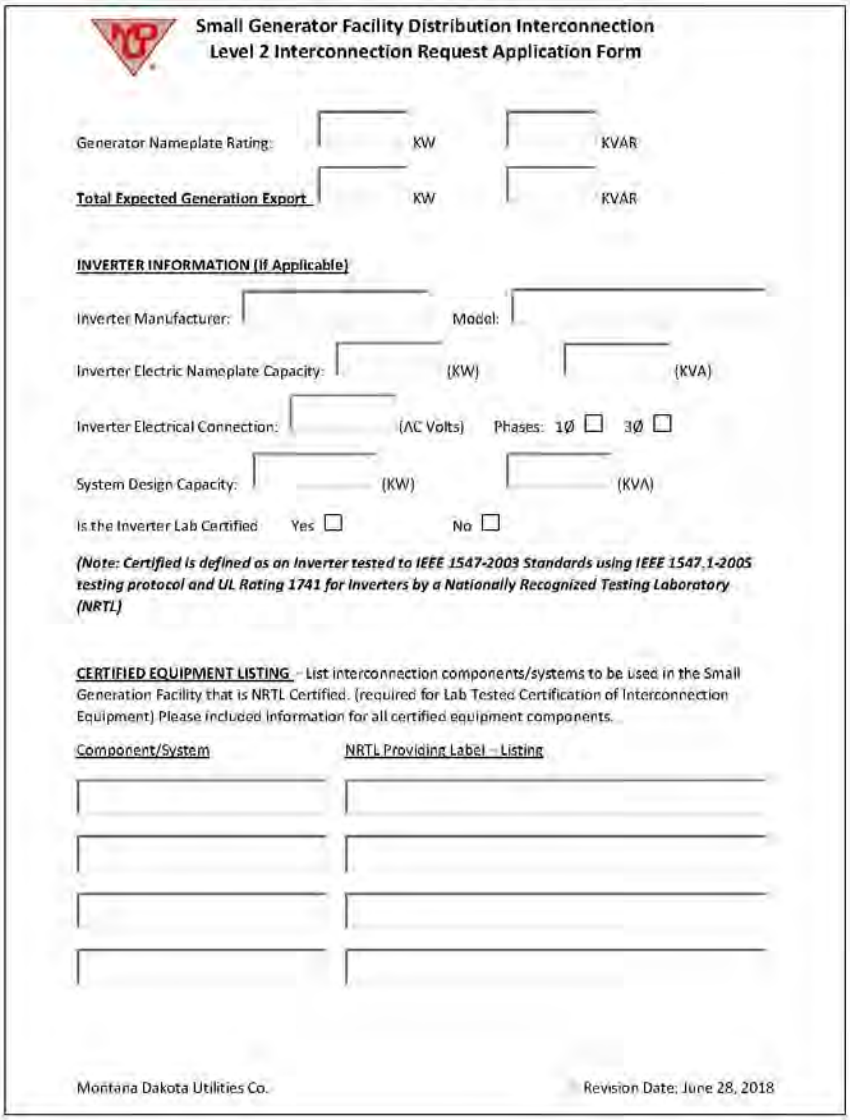
Prime Mover: Photovoltaic ☐
Reciprocating Engine ☐
Fuel Cell ☐
Turbine ☐
Micro Turbine ☐
Other ______

Energy Source: Solar ☐
Wind ☐
Hydro ☐
Diesel ☐
Natural Gas ☐
Steam ☐
Fuel Oil ☐
Other ______

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96



Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Generator Nameplate Rating: ____ KW ____ KVAR

Total Expected Generation Export ____ KW ____ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ____ Model: ____

Inverter Electric Nameplate Capacity: ____ (KW) ____ (KVA)

Inverter Electrical Connection: ____ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ____ (KW) ____ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

CERTIFIED EQUIPMENT LISTING – List interconnection components/systems to be used in the Small Generation Facility that is NRTL Certified. (required for Lab Tested Certification of Interconnection Equipment) Please incluced information for all certified equipment components.

Component/System	NRTL Providing Label – Listing

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Attach Information from All Other Certified Interconnection Equipment Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes.

☐ - Complete Net Metering Application Addendum "A" (If Applicable)

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ Attach a One Line Diagram of the Proposed system that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC:

Note: An application fee is required before the application can be processed. Please verify that the appropriate fee is included with the application:

Application Fee Included: ☐ Amount: $200.00

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ____

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Title: ______________________ Date: ______________________

ADDENDUM "A" NET METERING RATE REQUEST

Net Metering Availability: The Net Metering Rate 92 is available to any customer that owns and operates a solar, wind, or hydroelectric generating facility utilizing these renewable energy sources with a capacity of not more than 50 KW and that is located on the customer's premises and that is intended primarily to offset part or all of the customer's own electrical requirements.

This Small Generator Application is requesting to be operated on the Net Metering Rate 92: YES☐ NO ☐

If "YES" please read and understand the NET METERING SERVICE RATE 92 and designate a start date for the start of the 12 month billing period: (Make a choice)

January 1st ☐

April 1st ☐

July 1st ☐

October 1st ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

*** Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non-Salient Rotor ☐

Torque: ______ Ft-Lb Rated RPM: ______

At Rated Generator Voltage and Current: Field Amperes: ______ Amps @ ______ %PF

Type of Exciter: ______

Output Power of Exciter: ______

Type of Voltage Regulator: ______

Locked Rotor Current: ______ Amps Synchronous Speed: ______ RPM

Winding Connection: ______

Min. Operating Frequency/Time: ______

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): ______ Ohms (P.U.)

Direct-axis Transient Reactance (X'd): ______ Ohms (P.U.)

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 2 Interconnection Request Application Form

Direct-axis Sub Transient Reactance (X"d): ______ Ohms (P.U.)

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

Locked Rotor Current: ______ Amps Base KVA: ______ KVA

Rotor Resistance (Rr): ______ Ohms Exciting Current: ______ Amps

Rotor Reactance (Xr): ______ Ohms Reactive Power Required: ______

Magnetizing Reactance (Xm): ______ Ohms ______ VAR's (No Load)

Stator Resistance (Rs): ______ Ohms ______ VAR's (Full Load)

Stator Reactance (Xs): ______ Ohms

Short Circuit Reactance (Xd): ______ Ohms

K (Heating Time Constant): ______ Total Rotating Inertia H: ______ KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: ______ Design Letter: ______ Temp. Rise: ______ °C

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

(See also Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 for Levels 3 & 4)

APPLICATION SCOPE:

LEVEL 3 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 MW in size and where power will not be exported beyond the interconnection point. This could be used as a demand control generator for customer load.

LEVEL 4 GENERATORS – Application shall be used to request the interconnection of a generator to operate in parallel with Montana-Dakota's Electric Distribution System. The generator can be up to 10 Megawatts (MW) in size, and does not qualify under the criteria of LEVEL 1, LEVEL 2, and LEVEL 3. This includes any Interconnection Request that was submitted and not approved under a LEVEL 1, LEVEL 2, or LEVEL 3 Interconnection Request.

Applicant/Interconnection Customer Contact Information

Name:

Mailing Address:

City: State: Zip Code:

Telephone (Daytime): Telephone (Evening):

Email Address:

System Installer/Consultant Engineer

Check if Owner Installed ☐

Name:

Mailing Address:

City: State: Zip Code:

Montana Dakota Utilities Co. Revision Date: June 28, 2018

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Telephone (Daytime): ____________ Telephone (Evening): ____________

Email Address: ____________

SITE INFORMATION

This application is requested for:
☐ A New Small Generator to be located on an Existing Service Location.
☐ A New Small Generator to located at a New Service Location.
☐ A Change to an Existing Small Generator Location.

Interconnection Address/Location ____________

Electric Service Information for Applicant's Facility Where Generator Will Be Interconnected

Capacity: ______ Amps Voltage: ______ Volts

Type of Service: Single Phase ☐ Three Phase ☐

Estimated Commissioning Date: ____________

Small Generator Facility General Information

Prime Mover: Photovoltaic ☐
Reciprocating Engine ☐
Fuel Cell ☐
Turbine ☐
Micro Turbine ☐
Other ____________

Energy Source: Solar ☐
Wind ☐
Hydro ☐
Diesel ☐
Natural Gas ☐
Steam ☐
Fuel Oil ☐
Other ____________

Generator Type: Synchronous ☐ Induction ☐ Not Applicable ☐

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

Generator Nameplate Rating: ______ KW ______ KVAR

Total Expected Generation Export ______ KW ______ KVAR

INVERTER INFORMATION (If Applicable)

Inverter Manufacturer: ______ Model: ______

Inverter Electric Nameplate Capacity: ______ (KW) ______ (KVA)

Inverter Electrical Connection: ______ (AC Volts) Phases: 1Ø ☐ 3Ø ☐

System Design Capacity: ______ (KW) ______ (KVA)

Is the Inverter Lab Certified Yes ☐ No ☐

(Note: Certified is defined as an Inverter tested to IEEE 1547-2003 Standards using IEEE 1547.1-2005 testing protocol and UL Rating 1741 for Inverters by a Nationally Recognized Testing Laboratory (NRTL)

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

FINAL CHECKLIST FOR APPLICATION:

☐ - Verify that the Application Information is filled out and complete.

☐ - Attach Information from the Inverter Manufacturer documenting the NRTL compliance testing to the IEEE 1547 and UL 1741 Standards and Codes. (If Applicable)

☐ - Complete Equipment Detail Addendum "A" – Prepare Lists and Attach Detailed Information.

☐ - Complete Synchronous Generator Data Addendum "B" (If Applicable)

☐ - Complete Induction Generator Data Addendum "C" (If Applicable)

☐ - Attach a Site Diagram of the Proposed System location indicating the locations of all proposed equipment at the Small Generator Site. This should include at a minimum, generator locations, electrical equipment, disconnect location, transformers, meters, and all other system related locations.

☐ - Attach a One-Line Diagram of the Proposed System that at a minimum includes the general connection of the Service Line, Meter, Load Center(s), Inverter(s), Generator(s), Transformer(s), and Disconnect Switch. Also include relay protection, control schematics, current and potential circuits, and alarm/monitoring circuits.

Is Facility a Qualified Facility? Yes ☐ No ☐

If yes, has the Applicant completed FERC's "Notice of Self Certification"? Yes ☐ No ☐

Verification Number Received from FERC:

Note: An application Deposit is required before the application can be processed. The actual cost of the studies and reviews necessary to provide for this Interconnection is the responsibility of Interconnection Applicant.

Application Deposit Included: ☐ Amount: $500.00 Deposit

Applicant Signature

I hereby attest that the information submitted on this application is accurate to the best of my knowledge.

Signature: ______________________________

Title: ____________________ Date: ____________________

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

GENERATOR CONNECTION

Transformer

Is there a Transformer needed between the Generator and Service Connection Point Yes ☐ No ☐

Transformer Detail: 3 Phase ☐ 1 Phase ☐

Capacity: ______ KVA Impedance: ______ % on BASE: ______ KVA

PRIMARY: Voltage: ______ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

SECONDARY: Voltage: ______ KV Connected: Delta ☐ Wye ☐ Grd Wye ☐

Power Circuit Breaker

Manufacturer: ______

Type: ______

Load Amp Rating: ______ Interrupting Amp Rating: ______

Trip Speed: ______ Cycles

Interconnection Relays

If Conventional individual relay: Attach a List and Include the following for each relay:

Manufacture, Model, Catalog Number, Function, Proposed Setting

If Microprocessor Controlled: List the following for each Setpoint:

Setpoint Function, Minimum, and Maximum Settings – Proposed Settings.

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Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "A" ADDITIONAL INTERCONNECTION EQUIPMENT DATA

Auxiliary Transformers

Current Transformers (If Applicable and for each Bank of Current Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, and Burden.

Potential Transformers (If Applicable and for each Bank of Potential Transformers in the One-Line)

List of the Manufacture, Model, Serial Numbers (all units), Proposed Ration Connection, Accuracy Class, Thermal Rating, and Burden.

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Small Generator Facility Distribution Interconnection
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ADDENDUM "B" SYNCHRONOUS GENERATOR DATA

Manufacturer: ______

Model Number: ______ Version Number: ______

*** Submit copies of the Saturation Curve and Vee Curve.**

Salient Rotor ☐ Non Salient Rotor ☐

Torque: ______ Ft-Lb Rated RPM: ______

At Rated Generator Voltage and Current: Field Amperes: ______ Amps @ ______ %PF

Type of Exciter: ______

Output Power of Exciter: ______

Type of Voltage Regulator: ______

Locked Rotor Current: ______ Amps Synchronous Speed: ______ RPM

Winding Connection: ______

Min. Operating Frequency/Time: ______

Generator Connection: Delta ☐ Wye ☐ Wye Grounded ☐

Direct-axis Synchronous Reactance (Xd): ______ Ohms (P.U.)

Direct-axis Transient Reactance (X'd): ______ Ohms (P.U.)

Direct-axis Sub-Transient Reactance (X"d): ______ Ohms (P.U.)

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SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection
Level 3 & 4 Interconnection Request Application Form

ADDENDUM "C" INDUCTION (Asynchronous) GENERATOR DATA

Manufacturer:

Model Number: Version Number:

Locked Rotor Current: Amps Base KVA : KVA

Rotor Resistance (Rr): Ohms Exciting Current: Amps

Rotor Reactance (Xr): Ohms Reactive Power Required:

Magnetizing Reactance (Xm): Ohms VAR's (No Load)

Stator Resistance (Rs): Ohms VAR's (Full Load)

Stator Reactance (Xs): Ohms

Short Circuit Reactance (Xd): Ohms

K (Heating Time Constant): Total Rotating Inertia H: KVA PU

Phase: Single Phase ☐ Three Phase ☐

Frame Size: Design Letter: Temp. Rise: °C

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Small Generator Facility Distribution Interconnection

Interconnection Feasibility Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ____ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Feasibility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection Feasibility Study as Attachment "A" attached to this agreement.

4. The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Applicant in its Application, as may be modified as the result of the Scoping Meeting. Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility

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Small Generator Facility Distribution Interconnection

Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application, the time to complete the Interconnection Feasibility Study may be extended by mutual agreement of the Parties.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The Feasibility Study and Report will include the following analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the Interconnection;

ii. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

iii. Initial review of grounding requirements and system protection; and

iv. A Description and non-binding estimated cost of facilities required to interconnect the Small Generator Facility to Montana-Dakota's Electric Distribution System in a safe and reliable manner.

7. The Interconnection Feasibility Study shall be completed and the results transmitted to the Interconnection Applicant within 30 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Feasibility Study Report within the 30-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

8. The Interconnection Applicant is responsible for the Feasibility Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Feasibility Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Small Generator Facility Distribution Interconnection

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):________________________________

Signed: ________________________________

Title: ________________________________

Date: ______________

[Insert name of Applicant]

Name (Printed):________________________________

Signed: ________________________________

Title: ________________________________

Date: ______________

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Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions in regard to a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection Feasibility Study Estimated Cost: $

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Small Generator Facility Distribution Interconnection

Interconnection System Impact Study Agreement

This agreement is entered into as of ________________, 20___, is by and between ____, ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ________________________________, and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"), and

Whereas, Montana-Dakota has completed a Small Generator Interconnection Feasibility Study and provided the results in the form of a Report to the Interconnection Applicant or the Feasibility Study was waived by mutual agreement of the Parties, and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection System Impact Study to assess the impact of interconnecting the proposed Small Generating Facility to Montana-Dakota's Electric Distribution System:

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the Agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection System Impact Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information affecting the scope of the Interconnection System Impact Study as Attachment "A" and attached to this agreement.

Small Generator Facility Distribution Interconnection

4. The Interconnection System Impact Study shall be based on the technical information provided by the Interconnection Applicant in its Application, results of the Feasibility Study Report (if performed), and any information agreed upon as a result of the Scoping Meeting. Montana-Dakota reserves the right to request additional technical information from the Interconnection Customer as reasonably becomes necessary consistent with Good Utility Practice during the course of the System Impact Study. If, in the course of the Study, the Interconnection Applicant finds it necessary to modify the Application Information or the technical information, the time to complete the Interconnection System Impact Study may have to be extended.

5. In performing the study, Montana-Dakota will rely, to the extent reasonably practicable, on existing studies of recent vintage. The Applicant will not be charged for such existing studies.

6. The System Impact Study will include the following detailed analyses necessary for the purpose of identifying a potential adverse system impact to Montana-Dakota's Electric Distribution System that would result from the proposed interconnection:

i. Short Circuit Analysis
ii. A Power Flow Analysis
iii. Verification of Interruption Equipment Ratings
iv. Protection Coordination Study
v. Voltage Drop and Flicker Study
vi. Effective Grounding Review
vii. System Stability Analysis
viii. Review of Set Points of Certified Equipment
ix. A Review of the Interconnection Impact on the EDS Operations.

7. The System Impact Study Report shall state the assumptions upon which it is based, state the results of the analyses, indicate any interconnection requirements or impediments, and will include preliminary changes and costs required to the Montana-Dakota Electric Distribution System in order to implement the Interconnection request. The System Impact Study preliminary changes and costs will include a list of facilities and changes that are required as a result of the Interconnection request and a non-binding good faith estimate of cost responsibility and time to construct.

8. The Interconnection System Impact Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Interconnection System Impact Study within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

Small Generator Facility Distribution Interconnection

9. The Interconnection Applicant is responsible for the Interconnection System Impact Study costs. The Study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection System Impact Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

[Insert name of Applicant]

Name (Printed):____

Signed: ____

Title: ____

Date: _______________

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SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection System Impact Study Estimated Cost: $

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Small Generator Facility Distribution Interconnection

Interconnection Facilities Study Agreement

This agreement is entered into as of _______________, 20___, is by and between _______________________________ ("Interconnection Applicant") and Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, The Applicant is proposing to develop a Small Generating Facility or adding generating capacity to an existing Small Generating Facility consistent with the Application completed by Interconnection Applicant on ______________________________; and

Whereas, The Interconnection Applicant desires to interconnect the Small Generating Facility with Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, Montana-Dakota has completed a Small Generator Interconnection System Impact Study and provided the results in the form of a Report to the Interconnection Applicant; and

Whereas, The Interconnection Applicant has requested Montana-Dakota to perform an Interconnection Facilities Study to list and provide estimate for all the costs and timing of system changes to implement the conclusions of the Interconnection System Impact Study in order to safely Interconnect the proposed small generator to the Electric Distribution System. This estimate would include any distribution equipment, metering equipment, operational impacts, or other costs associated with the operation of the new proposed interconnection on the Montana-Dakota Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement the terms, with initial capitalization, specified shall have the meanings indicated within the agreement.

2. The Interconnection Applicant requests and Montana-Dakota shall cause to be performed an Interconnection Facility Study consistent with the Montana-Dakota Small Generator Facility Interconnection Rules and the Administrative Rules of Montana Rule 38.5.

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Small Generator Facility Distribution Interconnection

3. Montana-Dakota and the Interconnection Applicant will provide any additional rules, assumptions, or information specific to or affecting the Interconnection Facilities Study as Attachment "A" and filed with this agreement.

4. The Interconnection Facilities Study shall include a detailed specification and listing of any system equipment, metering equipment, operational costs (including overheads), or other costs (including overheads) required to safely interconnect the proposed small generator interconnection to the Montana-Dakota Electric Distribution System. Details of the Interconnection Facilities Study Report will include a listing of the required equipment, the electrical configuration of the Interconnection system estimate, an estimate of the specific costs of each item, and the estimate of the timing required to performing the system changes estimated for the interconnection.

5. The Interconnection Facilities Study shall be completed and the results transmitted to the Interconnection Applicant within 45 business days from the execution of this agreement by the parties. If Montana-Dakota is unable to complete the Facilities Study Report within the 45-business day timeline, the company will notify the Interconnection Applicant with an explanation of the delay and a time line of the expected completion.

6. The Interconnection Applicant is responsible for the Interconnection Facilities Study costs. The study cost shall be based on the company's actual costs and will be invoiced to the Interconnection Applicant upon delivery of the Interconnection Facilities Study Report. The Interconnection Applicant shall pay Montana-Dakota within 30 calendar days of receipt of the invoice or resolution of any dispute.

Small Generator Facility Distribution Interconnection

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written:

For Montana-Dakota:

Name (Printed):____

Signed: ____

Title: ____

Date: __________________

[Insert name of Applicant]

Name (Printed):____

Signed: ____

Title: ____

Date: __________________

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Small Generator Facility Distribution Interconnection

Attachment "A"

Note: Include any additional specification or study assumptions, in regards to, a scoping meeting, Feasibility Study, System Impact Study, or agreed upon details between the parties.

Scoping Meeting Date: ______________________________

Interconnection Facilities Study Estimated Cost: $

Montana Dakota Utilities Co. Revision Date: June 28, 2018

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

This Interconnection Agreement ("Interconnection Agreement' or "Agreement") is entered into effective as of Click or tap to enter a date. ("Effective Date") by and between Click or tap here to enter the name of the Applicant for this Interconnection Agreement. ("Applicant") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Applicant and Montana-Dakota each may be referred to as a "Party," or collectively as the "Parties."

<u>Recitals</u>:

Whereas, the Applicant is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on ***Click or tap to enter a date.***;

Whereas, the Applicant desires to interconnect the Small Generator Facility with the Montana-Dakota's Electric Distribution System ("EDS"); and

Whereas, the Agreement shall be used for all approved Level 1, Level 2, Level 3, and Level 4 Applications according to the terms and procedures set forth in Montana-Dakota's Small Generator Facility Distribution Interconnection Rules and Procedures Rate 96 tariff (Rate 96). Terms with initial capitalization, when used in this Agreement, shall have the meanings given in Rate 96 and, to the extent this Agreement conflicts with Rate 96, the Rate 96 tariff shall take precedence.

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

<u>Article 1.</u> Scope and Limitations of Agreement

1.1 Scope

The Agreement establishes standard terms and conditions approved by the Montana Public Service Commission (the "Commission") under which the Small Generator Facility with a Name Plate Capacity of 10 MW or smaller will interconnect to, and operate in Parallel with Montana-Dakota's EDS. Additions, deletions, or changes to the standard terms and conditions of an Interconnection Agreement will not be permitted unless they are mutually agreed to by the Parties and approved by the Commission if required by Rate 96.

1.2 Power Purchase

The Agreement does not constitute an agreement to purchase or deliver the Applicant's power nor does it constitute an electric service agreement.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

1.2.1 **Other Agreements.**
Nothing in the Interconnection Agreement is intended to affect any other agreement between the Montana-Dakota and the Applicant or another Interconnection Customer. However, in the event that the provisions of the Agreement are in conflict with the provisions of other Montana-Dakota tariffs, the Montana-Dakota tariff shall control.

1.3 **Attachments to Interconnection Agreement**

An Operations and Maintenance Schedule shall be attached to the Interconnection Agreement and the Applicant shall adhere to that schedule. Either Party may require that any of the following addendums be included as part of the Interconnection Agreement:

(A) Copy of the Interconnection Application
(B) Description of the project;
(C) a Billing Schedule;
(D) a List of non-binding milestones for each party;
(E) Scope of Work;
(F Operational Guidelines; and
(G) List of Major Permits needed by the Applicant.
(H) Assignment Acknowledgement Agreement

1.4 **Responsibilities of the Parties**

The Parties shall perform all obligations of the Agreement in accordance with all applicable laws and rules.

The Applicant will construct, own, operate, and maintain its Small Generator Facility in accordance with the Agreement, the IEEE Standard 1547-2003 version, the most currently adopted National Electric Code, state and federal law, and all other applicable standards required by the Commission. Each Party shall be responsible for the safe installation, maintenance, repair, and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and personal injury.

To the extent applicable, the allocation of responsibility for the design, installation, operation, maintenance, and ownership of Interconnection Facilities shall be as prescribed in Rate 96.

1.5 **Parallel Operation and Maintenance Obligations**

Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of the Interconnection Agreement, the Applicant will abide by all written provisions for operation and maintenance as required by Montana-Dakota.

1.6 **Power Quality**

The Applicant will design its Small Generator Facility to maintain a composite

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. Any special operating requirements will be detailed in an attached form. Under no circumstances shall these additional requirements for voltage or reactive power support exceed the normal operating capabilities of the Small Generator Facility.

Article 2 Inspection, Testing, Authorization, and Right of Access

2.1 Testing and Inspection

Applicant will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in Rate 96. The Interconnection will not be final until the Witness test and certificate of completion provisions in Rate 96 have been satisfied or waived in accordance with Rate 96.

To the extent that an Applicant decides to conduct interim testing of the Small Generator Facility prior to the witness test, it may request that the Montana-Dakota observe these tests and that these tests be deleted from the final witness test. If Montana-Dakota sends qualified personnel to the Small Generator Facility to observe such interim testing, it will be doing so at the Company's own expense.

2.2 Right of Access:

Montana-Dakota will have access to the Applicant's premises, at no cost, for any reasonable purpose in connection with the Interconnection Application, the Interconnection Agreement, or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency, hazardous condition, or violation of the terms of this agreement.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

The Agreement shall become effective upon the Effective Date stated in the introductory paragraph.

3.2 Term of Agreement

The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or another period mutually agreed to by Parties in a written amendment, unless terminated earlier by default of either Party, voluntary termination by the Interconnection Customer, or by action of the Commission.

3.3 Termination

The Applicant may terminate this Agreement at any time by giving Montana-Dakota twenty (20) business days written notice. Either Party may terminate

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

this Agreement pursuant to Section 5.6.2 after default by the other Party. The Commission may order termination of this Agreement. Upon termination of this Agreement, the Small Generator Facility will be disconnected from Montana-Dakota's EDS at the Applicant's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination. The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Restoration of Interconnection When Disconnected

The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Montana-Dakota's EDS to their normal operating state as soon as reasonably practicable following any disconnection pursuant to the rules.

Article 4. Cost Responsibility and Billing

The Applicant is responsible for the application fee, cost of studies, and for such facilities, equipment, modifications, and upgrades identified under the process prescribed in Rate 96.

4.1 Minor EDS Modifications

The Applicant will bear the costs of making minor modifications to Montana-Dakota's EDS as may be necessary to gain approval of an Application.

4.2 Interconnection Facilities (Company Owned)

When necessary under the process prescribed in Rate 96, Montana-Dakota will identify the interconnection facilities ("Interconnection Facilities") necessary to safely interconnect the Small Generator Facility with the EDS. Montana-Dakota will itemize the Interconnection Facilities for the Applicant, including the cost of the facilities and the time required to build and install those facilities. The Applicant is responsible for the cost of the operational changes or physical additions to the Company-owned Interconnection Facilities.

4.3 Interconnection Equipment (Customer Owned)

The Applicant is responsible for all costs associated with the installation, operation and maintenance of the interconnection equipment not owned by the Company

4.4 System Upgrades

Montana-Dakota will design, procure, construct, install, and own any System Upgrades under the process prescribed in Rate 96 when applicable. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Applicant. An Interconnection Customer may be entitled to financial compensation from other utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

Commission or by terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 Adverse System Impact

Montana-Dakota is responsible for identifying adverse system impacts on any affected systems and for determining what mitigation activities or upgrades may be required to accommodate a Small Generator Facility. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Applicant. The Applicant may be entitled to financial compensation from other utility Interconnection Customers or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Applicant, to the extent provided by a tariff or a separate Commission rule or order.

4.6 Billing

Montana-Dakota may require a deposit up to 50% of the cost estimate to be paid up front by the Applicant for the studies, interconnection facilities, system upgrades, or other costs associated with the interconnection request. Progress billing, final billing, and payment schedules must be agreed to by the Parties prior to commencing work. The Billing Schedule should be attached to the agreement as "Attachment C" as needed.

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment

The Interconnection Agreement may be assigned by either Party upon fifteen (15) business days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

5.1.2 The Applicant shall have the right to assign the Agreement, without the consent of Montana-Dakota, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement. Attachment (H) can be used to document the assignment of a new owner to an existing facility.

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

5.1.3 Any attempted assignment that violates this Article is void and ineffective.

5.2 Limitation of Liability and Consequential Damages

A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees caused by any act or omission in its performance of the provisions of an Interconnection Agreement. Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 Indemnity

5.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of the Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article, as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle, or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.4 Consequential Damages

With the exception of third party claims, neither Party shall be liable to the other Party, under any provision of the Agreement, for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 **Force Majeure**

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. If the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by Rule that the Rule does not permit the Parties to mutually waive.

5.6 **Default**

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement. Upon a default, the non-defaulting Party shall give written notice of such default to the defaulting Party. Except as provided in Article 5.6.2, the defaulting Party shall have sixty (60) calendar days from receipt of the default notice within which to cure such default.

5.6.2 If a default is not cured as provided for in this Article, or if a default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate the Agreement by written notice, and be relieved of any further obligation hereunder and, whether or not that Party terminates the Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternately, the non-

defaulting Party shall have the right to seek dispute resolution with the Commission in lieu of termination. The provisions of this Article will survive termination of the Agreement.

Article 6. **Insurance**

At all times during this Agreement, each Party shall obtain and maintain the following insurance:

General Liability Insurance with limits not less than $1,000,000. Limits may be met in combination of both primary and umbrella/excess policies. Upon signing the Agreement, each Party shall furnish to the other Party certificates of insurance as evidence showing that the insurance policy(s) to be carried in accordance with this provision have been obtained. All insurance to be carried pursuant to the above shall be endorsed to require 30 day written notice prior to effective date of any modification or cancellation of such insurance to the certificate holder, unless such cancellation is due to non-payment, then 10 day written notice is required.

Article 7. **Dispute Resolution**

Parties will adhere to the dispute resolution and complaint process in Rate 96.

Article 8. **Miscellaneous**

8.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation, and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Montana, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 Amendment

The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of Rate 96 and applicable Commission Orders and provisions of the laws of the State of Montana.

8.3 No Third-Party Beneficiaries

The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

8.4 Waiver

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by Rate 96.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 **Entire Agreement**

The Interconnection Agreement, including any supplementary form attachments that may be necessary, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under the Agreement.

8.6 **Multiple Counterparts**

The Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 **No Partnership**

The Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 **Severability**

If any provision or portion of the Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of the Agreement shall remain in full force and effect.

8.9 **Subcontractors**

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

Nothing in the Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in the Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under the Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of the Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under the Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by the Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

Either Party will have the right to make a unilateral filing with the Commission to modify the Interconnection Agreement. This reservation of rights provision includes, but is not limited to, modifications with respect to any rates, terms, and conditions, charges, classification of service, tariff, or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. Notices

9.1 General

Unless otherwise provided in the Agreement, any written notice, demand, or request required or authorized in connection with the Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the persons specified below:

If to the Interconnection Applicant:

Attention: ______________________________

Address: ____

City: ____________________________ State: _____________ Zip: _______

Phone: ____________________ E-mail: ___________________

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

If to the Interconnection Applicant:

Attention: ______________________________

Address: ____

City: __________________________ State: ____________ Zip: _______

Phone: __________________ E-mail: __________________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ______________________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.3 Designated Operating Representative

The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of the Agreement. This person or persons will also serve as the point of contact with respect to operations and maintenance of the Party's facilities:

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

If to the Interconnection Applicant:

Attention: ____________________

Address: ____________________

City: ____________________ State: __________ Zip: ______

Phone: ____________ E-mail: ____________

If to Montana-Dakota:

Montana Dakota Utilities Company

Attention: ____________________

400 North Fourth Street
Bismarck, North Dakota 58501
Phone 1-800-638-3278

9.4 Changes to the Notice Information

Either Party may change this notice information by giving five business days written notice prior to the effective date of the change.

Article 10 Signatures

IN WITNESS WHEREOF, the Parties have caused the Agreement to be executed by their respective duly authorized representatives.

Montana-Dakota	Interconnection Applicant
Name: ____________	Name: ____________
Title: ____________	Title: ____________
Signature: ____________	Signature: ____________
Date: ____________	Date: ____________

SMALL GENERATOR FACILITY DISTRIBUTION INTERCONNECTION RULES AND PROCEDURES Rate 96

Interconnection Agreement for Small Distribution Generator Facility Level 1, Level 2, Level 3, or Level 4 Interconnection (10 MW or smaller located in the State of Montana)

ADDENDUM "H" ASSIGNMENT ACKNOWLEDGEMENT AGREEMENT

APPLICATION SCOPE: For a Small Generator System that is incorporated into a building facility that has a current active Interconnection Agreement for Small Distribution Generator Facility approved by Montana Dakota Utilities Company. The Small Distribution Generator Facility Agreement will automatically transfer to the new owner upon the sale of the property and completion of this Assignment Acknowledgement Agreement by the New Owner-Operator. A copy of the original Interconnection Agreement will be sent to the New Owner-Operator for the purpose of this agreement.

Recitals:
Whereas, an existing Small Distribution Generator Facility is located at: ____________________ ______________________ (the "Property"), and operates pursuant to an Interconnection Agreement for Small Distribution Generator Facility dated the ______ day of __________, 20____ (the "Agreement") with Montana-Dakota Utilities Company, a Division of MDU Resources Group, Inc., hereinafter referred to as "Montana-Dakota", with principal offices at 400 North Fourth Street, Bismarck, North Dakota 58501.

Whereas, a new owner has purchased the "Property" and desires to operate the Small Generator System under the same requirements set forth in the "Agreement".

Whereas, a copy of the original Interconnection Agreement is attached to this Acknowledgement Agreement.

AGREEMENT
Now, therefore, the New Owner-Operator is assigned and assumes all rights and obligations under the "Agreement".

Montana-Dakota - Acknowledgement	New Owner-Operator
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________
Signature: ____________________	Signature: ____________________
Date: ____________________	Date: ____________________

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I. PURPOSE:

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

The Company undertakes to furnish service subject to the rules and regulations of the Public Service Commission of Montana (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 Montana.

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 expressed 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 and water well pumps on the same premise as the living quarters, used for single family 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 nonresidential 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 salons, 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. CUSTOMER 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 for residential service shall not exceed one-sixth of the estimated annual billings. For non-residential

service, the amount of the deposit shall not exceed 25 percent of the estimated annual billings.

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

iii. Interest on deposits held shall be accrued at the rate of .5 percent per month. Interest shall be computed from the receipt of deposit to the time of refund or of termination. Interest shall be credited to the customer's account annually during the month of December.

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

3. LATE PAYMENT CHARGE:
Amounts billed for energy will be considered past due if not paid by the due date shown on the bill.
   i. For residential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the second subsequent billing date, provided however, that such amount shall not apply where a bill is in dispute, written payment schedule has been arranged and complied with, or where the Low Income Energy Assistance Program (LIEAP) is being utilized up to the point where the funds are exhausted and the recipient has full responsibility for the account. In the event of a breach of a written payment

arrangement, an amount equal to 1% of the total remaining unpaid balance shall apply beginning 60 days after the date of the last payment under the payment arrangement. Such amount shall also apply (where the LIEAP program was utilized) to the total remaining unpaid balance on all accounts beginning 60 days after the LIEAP program no longer applies to such account.

ii. For nonresidential customers, an amount equal to 1% per month will be applied to any unpaid balance existing at the immediate subsequent billing date.

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

4. RETURNED CHECK CHARGE:
A charge of $30.00 will be collected by the Company for each check not honored by customer's financial institution for any reason.

5. MANUAL METER CHECK CHARGE:
A charge of $18.35 will be assessed monthly for 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. Customers 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 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 or other political subdivision for the privilege of conducting its utility operations therein.

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

7. UTILITY SERVICES PERFORMED AFTER NORMAL BUSINESS HOURS:
For service requested by customer for cut-ins, cut-outs, and disconnection or reconnection of service after the Company's regular business hours and on Saturday, Sunday, or legal holidays, a charge will be made for labor at standard overtime service rates and material at retail prices.

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

To ensure the Company can service the customer during normal business hours, the customer's call must be received by 12:00 p.m. on a regular work day for a disconnection or reconnection of service that same day. For calls received after 12:00 p.m. on a regular work day, customers will be advised that overtime service rates will apply unless service can be scheduled for a future workday.

8. RECONNECTION FEE FOR SEASONAL CUSTOMER:
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. All bills for services 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 Montana Public Service Commission.
   - ii. The Company may collect a fee of $20.00 before restoring electric service which has been disconnected for nonpayment of service bills.

10. DISCONTINUANCE OF SERVICE FOR CAUSES OTHER THAN NONPAYMENT OF BILL:
    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. BILLING ERRORS:
Billing error means any bill issued by Company that is not designated as an estimate and that understates the amount owed by the customer. It also means the Company's failure to bill a customer, although there was energy consumption which would, under the Company's normal billing practices, be billed to the customer.
    i. When a billing error is discovered which is not the result of theft by the customer, the Company may submit a bill to the customer based

on the corrected information for a period not to exceed six months from the date the billing error is discovered.

ii. Billing errors on accounts of industrial customers are not limited to the six-month period applicable to all other customers.

14. INSTALLING TEMPORARY METERING OR SERVICE FOR ELECTRIC FACILITY:
A customer requesting temporary metering service will be charged on a time and material basis in accordance with Electric Service Rules and Regulations Rate 110.

15. SERVICES ON CUSTOMER PREMISES – ELECTRIC NONCHARGEABLE – UTILITY SERVICES:
   i. Fire Call
   ii. Investigate hazardous condition on customer premises
   iii. No lights or power investigation
   iv. Maintenance or repair of Company-owned equipment on the customer's premise –
      a. Meter
      b. Overhead service line
      c. Underground service line
   v. Checking voltage or loads
   vi. Locating radio, cb or television interference
   vii. High bill complaint
   viii. Cut-ins and cut-outs (regular work hours)

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

~~Reserved for future use~~

~~Reserved for future use~~

~~Reserved for future use~~

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC SERVICE RULES and REGULATIONS

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Section 100 - General

101. 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 Commission 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.

102. 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.

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. Any customer may be required to make a deposit as required by the Company. 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.

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. The Company will make reasonable effort to contact the customer, but the Company reserves the right to interrupt service to conduct maintenance on metering equipment, including an exchange of the meter.

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 customer's premise. It is the obligation of the customer to consult with the Company regarding maximum available 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 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 hold 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 conduit 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 results 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 (Only allowed by special request – see Section 302.3)
**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 Electrical Code, state code, and local ordinances. Bare neutral wire shall not be installed in 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 may not be 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 Electrical 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 150feet, 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 actual 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 the 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. The customer will utilize meter sockets from a Company approved list of manufacturers and models as posted on the Company's website. 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. U.L. approved, ringless style.
2. 100 ampere minimum for overhead service installations.
3. 150 ampere minimum for underground service installations.
4. Stud connectors are required for all sockets rate 320 amps or greater.
5. For sockets rated below 320 amps, stud connectors are recommended. Only Company specified meter sockets are approved with lay-in connectors.
6. Equipped with a fifth terminal in the nine o'clock position where network metering is required.

7. A lever by-pass feature is required for all commercial and industrial installations. Upon review by Company, an exemption may be provided.
8. 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. Customer must provide hub closing plate.
4. Automatic by-pass feature is not acceptable.

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. For 480 volt service, enclosures must be sized to include room to mount voltage transformers or a separate weatherproof enclosure may be provided by the customer to mount 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 rated disconnect 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 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.

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 place on the exterior of the meter base on a non-removal 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 the 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 Commission.

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.

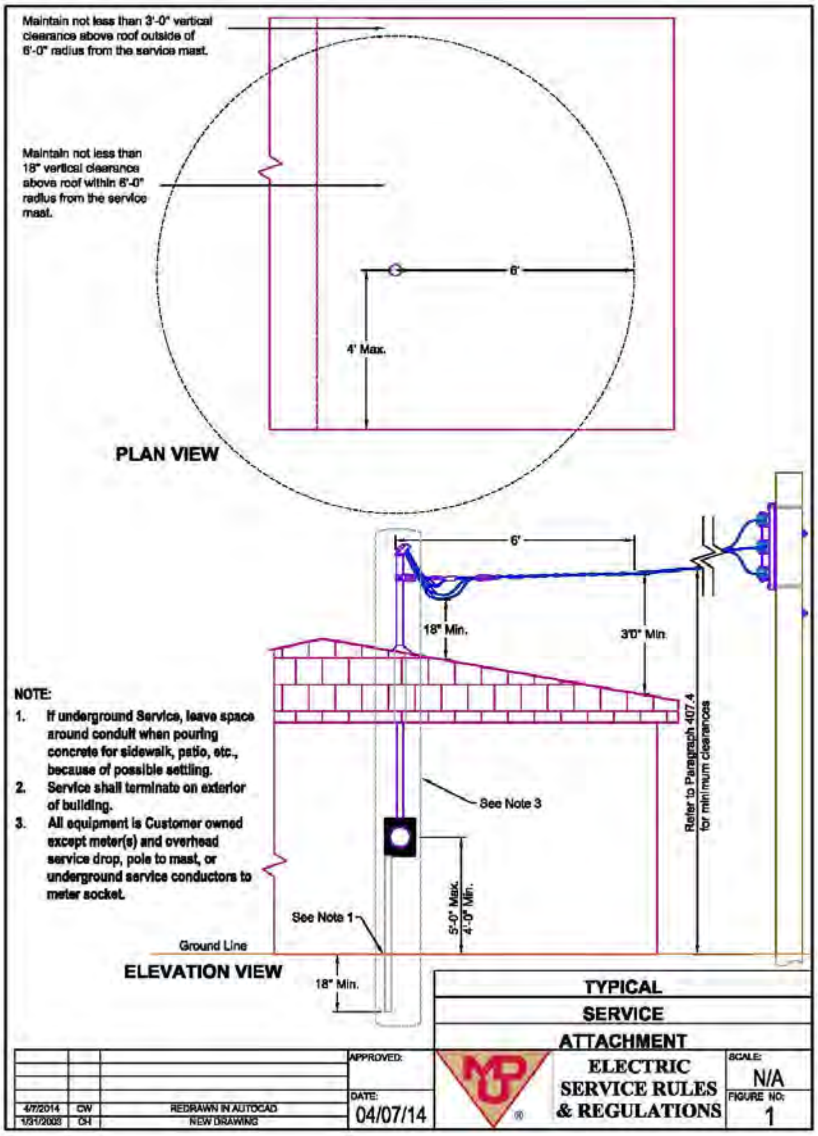
707. Flashing Display Signs
The Company reserves the right to refuse service for "flashing" display signs or display lighting where such service would interfere with voltage regulation of the secondary system.

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.



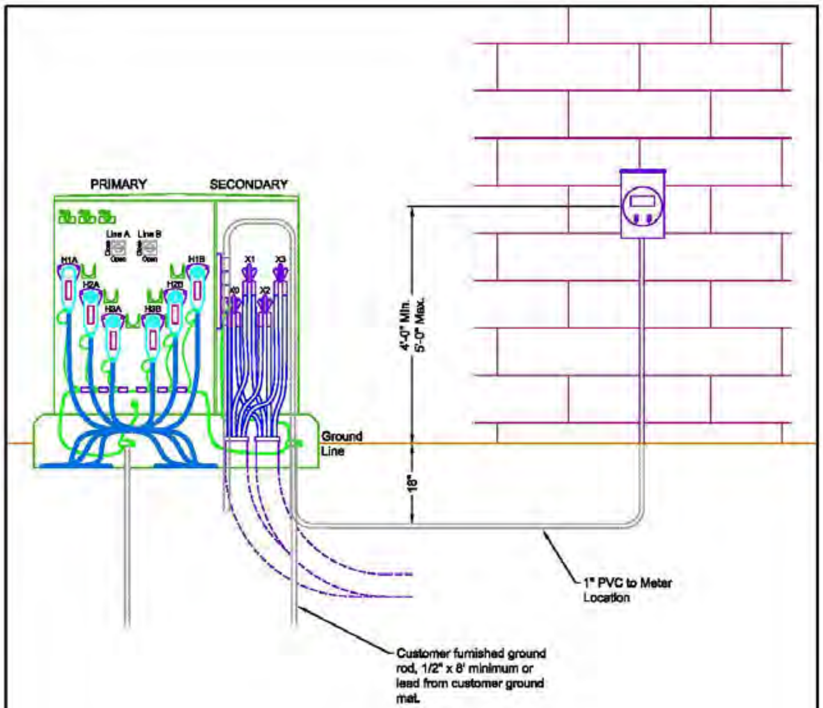
Maintain not less than 3'-0" vertical clearance above roof outside of 6'-0" radius from the service mast.
Maintain not less than 18" vertical clearance above roof within 6'-0" radius from the service mast.
6'
4' Max.
PLAN VIEW
6'
18" Min.
3'0" Min.
NOTE:
1. If underground Service, leave space around 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
1/31/2003 CH NEW DRAWING

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

State of Montana
Electric Rate Schedule

Volume No. ~~4~~5
~~1st Revised~~ Original Sheet No. 61.30
~~Canceling Original Sheet No. 61.30~~

ELECTRIC SERVICE RULES AND REGULATIONS Rate 110



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.

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

TRANSFORMER RATED METERING PADMOUNT TRANSFORMER

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A
FIGURE NO: 2

Issued: ~~June 24, 2015~~ November 4, 2022

By: ~~Tamie A. Aberle~~Travis R. Jacobson
Director - Regulatory Affairs

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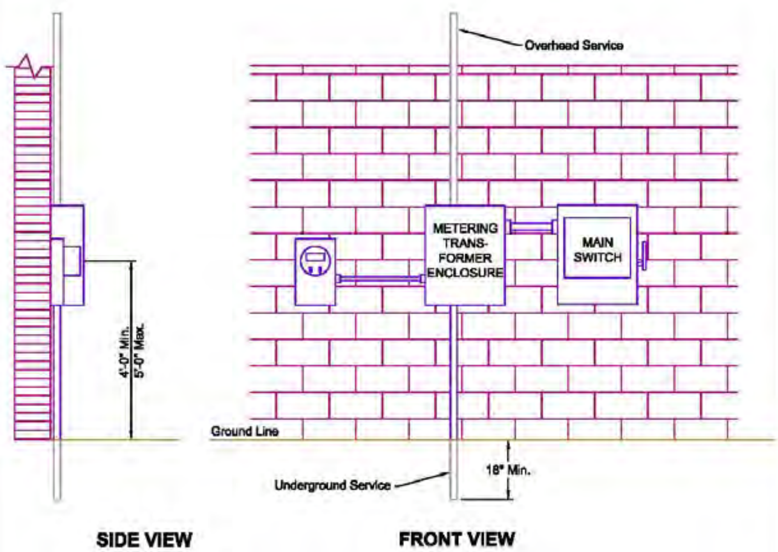
~~Docket No. D2015.6.51~~
~~Effective with service rendered on and after April 1, 2016~~

ELECTRIC SERVICE RULES AND REGULATIONS Rate 110



NOTE:

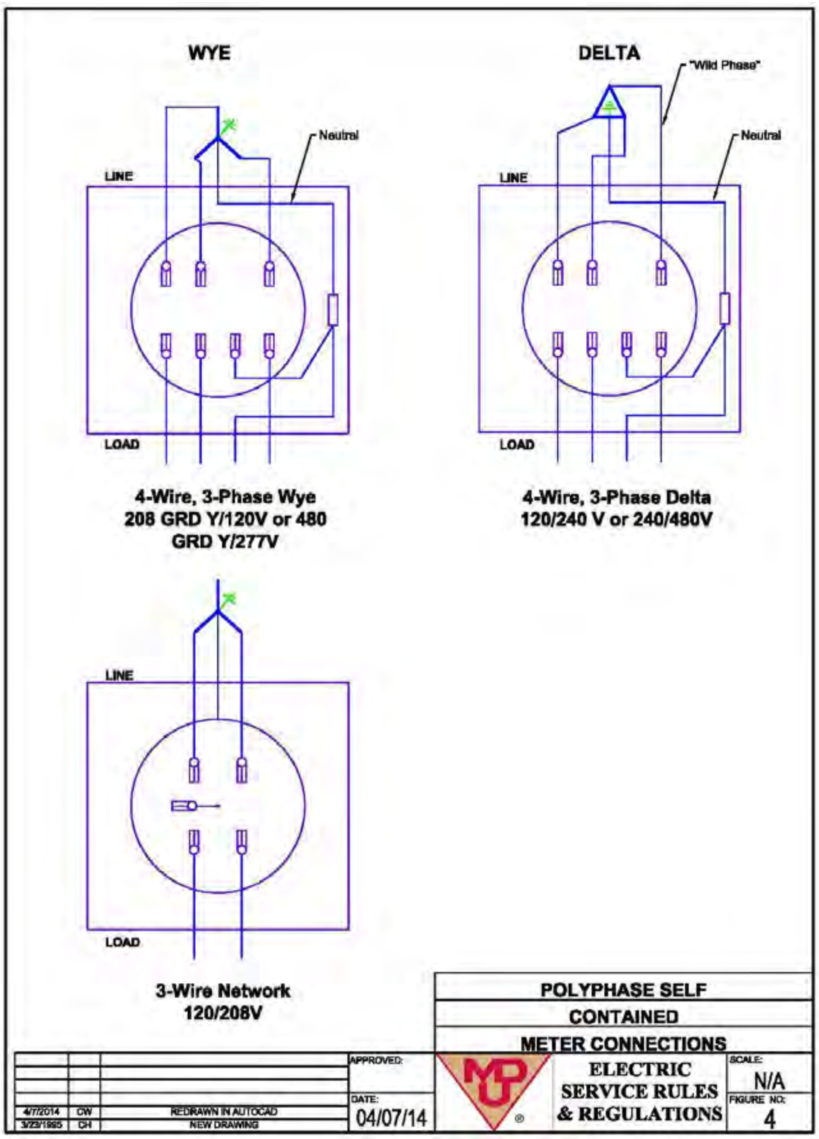
1. Ground neutral to metering transformer enclosure by direct connection or by ground wire.
2. Instrument transformer enclosure to be furnished and installed by customer. Minimum dimensions for enclosure is 24" x 30" x 10" where practical. Metering transformers furnished and installed by Company.
3.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

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

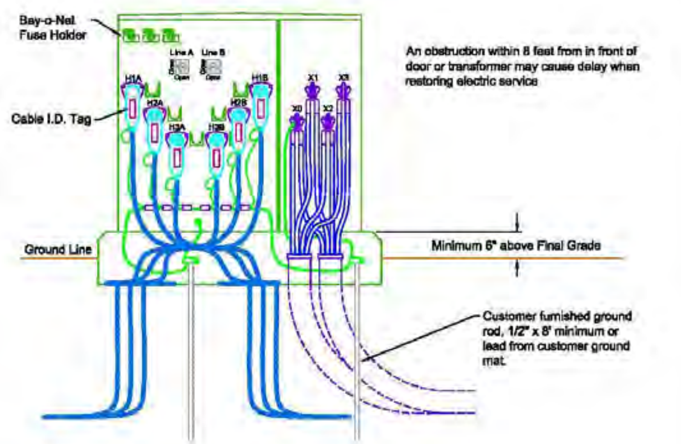
TRANSFORMER RATED METERING
OVERHEAD OR
UNDERGROUND SERVICE

ELECTRIC SERVICE RULES & REGULATIONS

SCALE: N/A
FIGURE NO: 3



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
3/23/1995 CH NEW DRAWING



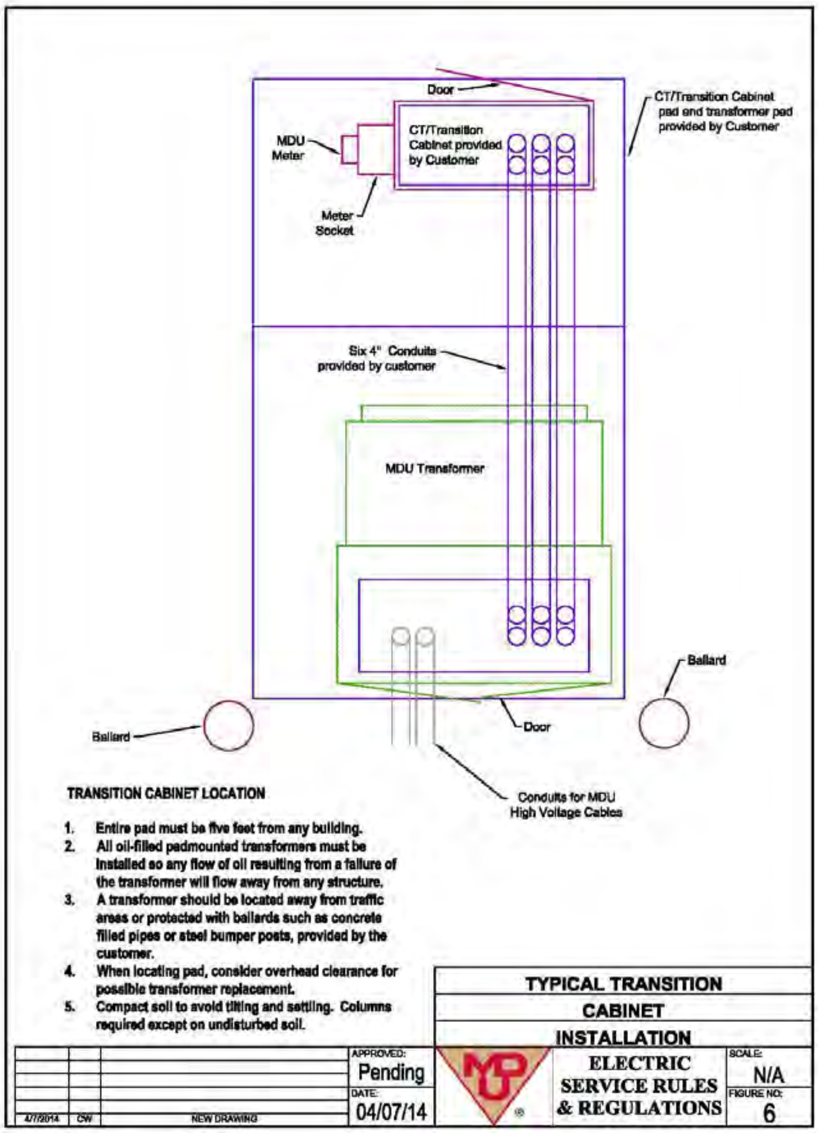
NOTES:

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.

4/7/2014	CW	REDRAWN IN AUTOCAD	APPROVED: Pending	TYPICAL PADMOUNT EQUIPMENT INSTALLATION
1/31/2003	CH	NEW DRAWING	DATE: 04/07/14	ELECTRIC SERVICE RULES & REGULATIONS
			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

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

State of Montana
Electric Rate Schedule

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 ~~two~~3.7 times the estimated annual revenue excluding fuel and purchased power (~~2~~ 3.7 to 1 ratio).

2. If the estimated project construction cost is greater than ~~two~~3.7 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~~3.7 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) Residential Customers - If within a ten-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). A customer may receive a refund only if the customer paid for the initial extension or subsequent connection to the extension and at the time the refund is issued, the customer owns the residential structure to which the extension or subsequent connection to the extension was made. No refund shall be made by Company to residential customer(s) after a ten-year period from which initial service is established, nor shall refunds be made in excess of the amount contributed.

2) Non-Residential Customers - 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). No refund shall be made by Company to non-residential customer(s) after a five-year period from which initial

service is established, nor shall refunds be made in excess of the amount contributed.

3) Developers of Subdivisions - Refunds 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. No refund shall be made by Company to a 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 Montana Public Service Commission.

ELECTRIC EXTENSION POLICY Rate 112

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~~

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 ± 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 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 ±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 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 two 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 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 two years rather than the entire vintage class.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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 North Dakota and Wyoming, the Public Utilities Commissions of Idaho, Minnesota, Oregon and South Dakota, 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 Montana. 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 who 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 Montana?

A. Montana is a part of Montana-Dakota’s interconnected electric system, which consists of generation, transmission, distribution, and general plant facilities serving approximately 25,600 customers in 30 communities in Montana. The Company’s Montana electric service area is served under one operating region with the regional office located in Dickinson, North Dakota and a number of district offices located in communities throughout Montana. As of June 30, 2022, the Company had 146 full and part-time employees who live and work throughout our Montana 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.

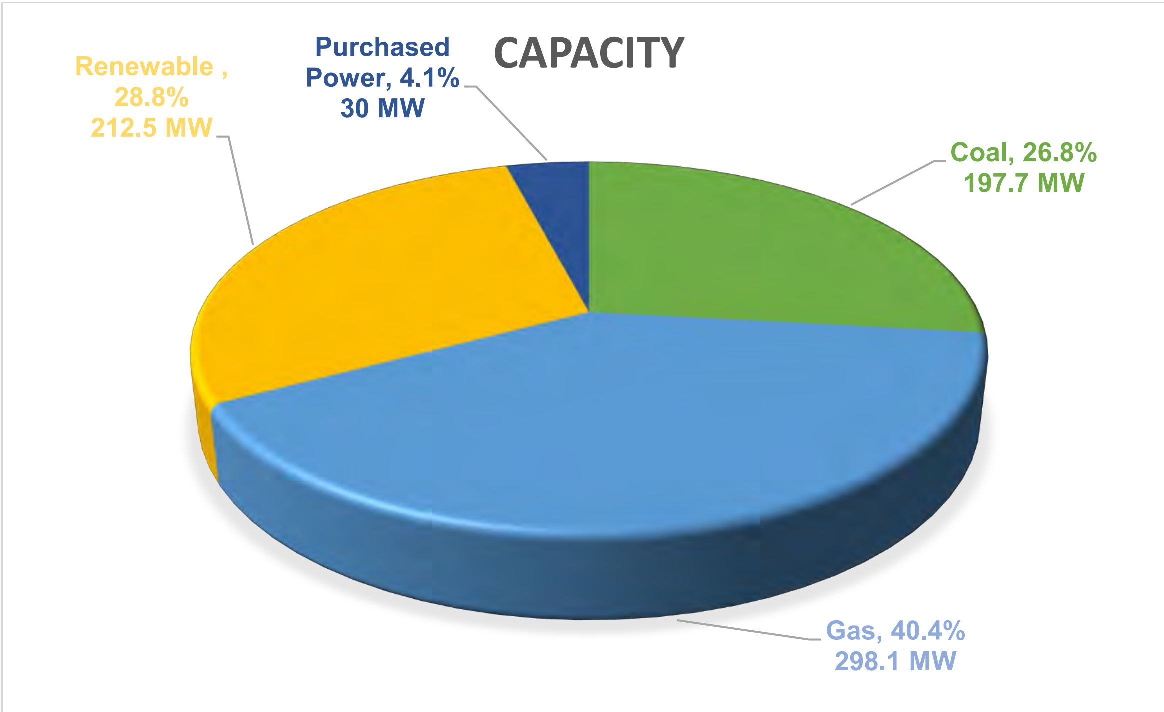
Q. Would you describe Montana-Dakota’s interconnected electric system?

A. Through its interconnected electric system, Montana-Dakota serves approximately 127,700 retail customers in portions of Montana, North Dakota, 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 pro forma June 2023 capacity mix is as shown below and is comprised of:

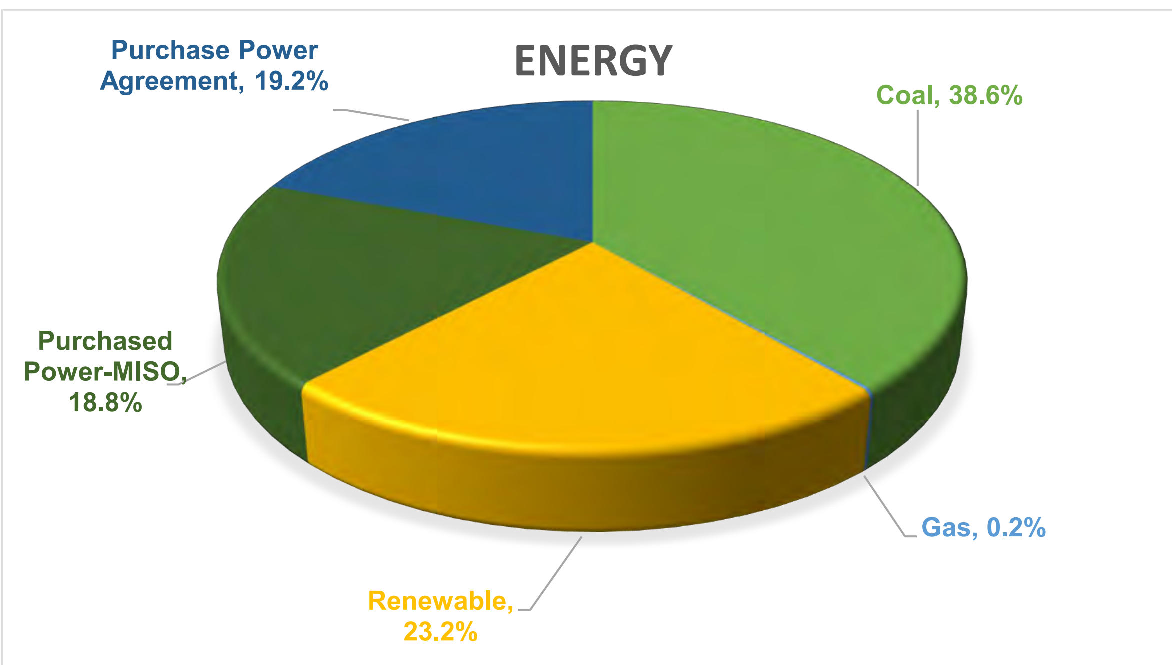
MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
GENERATION FACILITIES
CAPACITY
PRO FORMA JUNE 2023

Facility	Nameplate Capacity (MW)	Percent of Total
Coal		
Big Stone	94.1	
Coyote	103.6	
Total	197.7	26.8%
Gas		
Miles City	23.2	
Glendive Unit I and II	75.5	
Heskett Unit III	89.0	
Heskett Unit IV 1/	88.0	
Lewis and Clark Unit II - RICE	18.7	
Portables	3.7	
Total	298.1	40.4%
Renewable		
Diamond Willow	30.0	
Ormat	7.5	
Cedar Hills	19.5	
Thunder Spirit	155.5	
Total	212.5	28.8%
Purchased Power 2/	30.0	4.1%
Grand Total 3/	738.3	100.0%

1/ Heskett Unit IV will be in service Spring 2023.
2/ Capacity is 90.0 MW until June 2023.
3/ Additionally the Company has a Demand-Side Management program that can reduce demand by 13.6 MW for Interuptible customers and 25.0 MW for Commercial customers.



Customers' pro forma July 2022- June 2023 energy requirements are provided by the following resources as shown below.



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 because our current rates do not reflect the cost of providing electric service to Montana-Dakota's Montana customers. For the twelve months ending June 30, 2022, the Company's Rate of Return was 6.513 percent. The Company reported in the 2021 annual report that it earned a Rate of Return of 5.52 percent. Both of these results are below the last authorized Rate of Return.

Q. When was the Company's last general rate case?

A. The Company's last rate case was Docket No. 2018.09.060, which resulted in a two-phase increase totaling $9.3 million or a 14.7 percent overall increase. Final rates in the case became effective on September 1, 2019, and September 1, 2020.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting $10,499,415 which represents a 15.2 percent increase, based on a July 2021 – June 2022 test year adjusted for known and measurable changes.

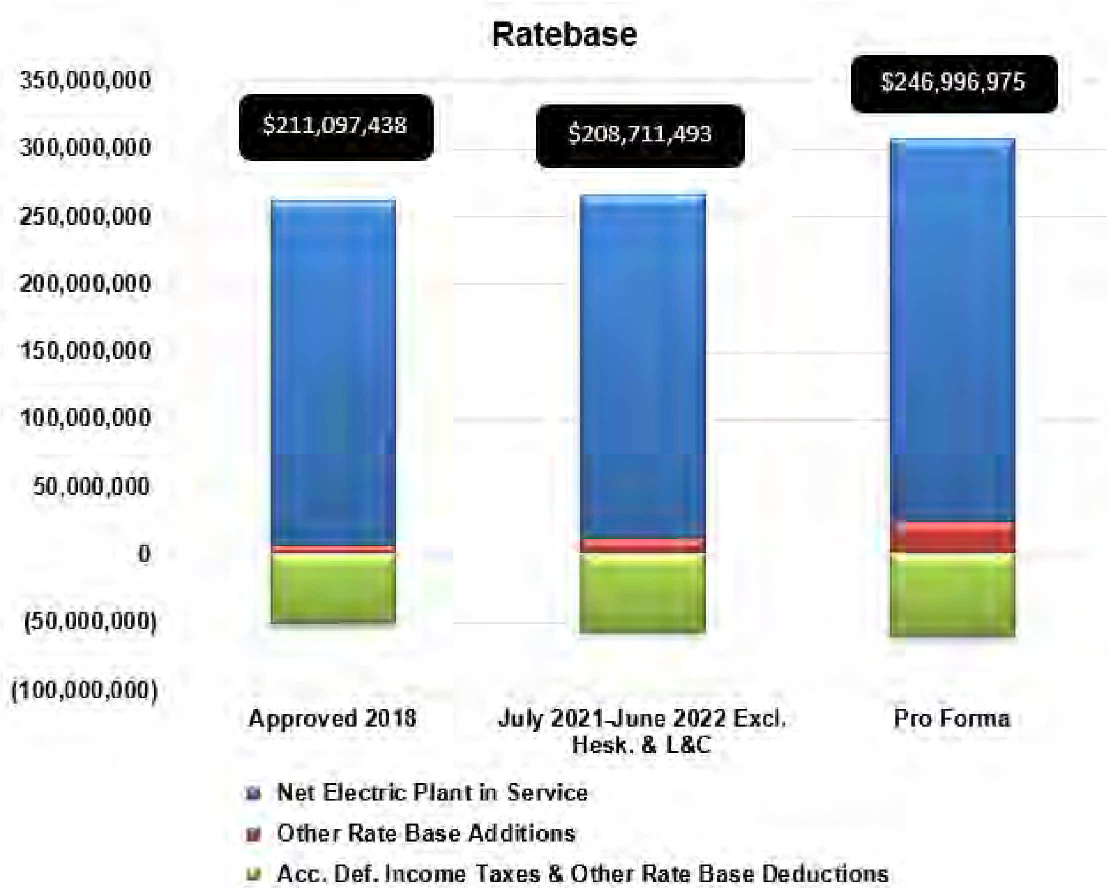
Q. How would this increase effect the Company's residential customers?

A. The typical non-space heating residential customer using an average of 792 kWh per month would see a monthly increase of approximately $16.96 or 19.1 percent. This equates to an annual increase of approximately $204. This filing also includes an increase in the daily basic service charge from 19 cents per day ($5.78 monthly) to 25 cents per day ($7.60 monthly).

Since the Company last filed a rate case in 2018 in Docket No. 2018.09.660, this filling represents an average annual increase of approximately 4.3 percent per year.

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

A. The need for an increase in electric rates is driven primarily by the investments made since the last rate case, including the Heskett IV gas turbine, increases in O&M expenses, and increases in property taxes. As depicted in the graph below, the Company's net adjusted rate base has grown approximately $35.9 million or 17 percent since the approved 2018 rate base.



As shown in the table below, the Company's total O&M costs have increased modestly over those approved in the Company's last electric rate case. After adjusting the 2018 Authorized O&M to exclude the costs associated with fuel and purchase power, the Company's Pro Forma O&M expenses are projected to increase approximately 7.97 percent. This represents a 1.7 percent increase per year since the last filing.

	Approved 2018	Pro Forma July 22 - June 23	Variance	Percent Variance
F&PP	$20,147,866	$18,211,673	($1,936,193)	-9.61%
Transmission	6,532,928	7,497,079	964,151	14.76%
Labor	8,073,582	8,177,241	103,659	1.52%
Benefits	1,587,550	1,520,115	(67,435)	-5.10%
Subcontract Labor	2,333,485	2,581,214	247,729	15.81%
Big Stone and Coyote	2,651,391	2,777,101	125,710	4.74%
Insurance	655,035	946,832	291,797	44.55%
Software Maintenance	454,084	700,627	246,543	54.29%
Other O&M	3,551,122	3,697,464	146,342	5.71%
Total O&M Expense	$45,987,043	$46,109,346	$122,303	0.27%
Total Excl. F&PP	$25,839,177	$27,897,673	$2,058,496	7.97%

The fuel and purchased power costs requested in this filing reflects 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 and Purchase Power Adjustment) that reflect the actual costs incurred.

Further, the substantial saving generated by the Lewis & Clark and Heskett plant closures largely offset increases in subcontract labor, software maintenance, and insurance expenses, as well as more recent inflationary increases. This has resulted in the modest overall increases included in the case.

Q. How have the Company’s labor expenses changed since the last case?

A. Montana-Dakota’s projected labor expenses for the year ending June 2023 have been largely flat when compared to 2018. As noted above, annual increases have been largely offset by coal plant closure savings.

Additionally, Montana-Dakota, like many other organizations in the country, has struggled to recruit, train, and retain personnel in the current competitive job market. Furthermore, the Company has faced increased labor market costs, particularly for those in entry level positions.

In late 2021 Montana-Dakota finalized its labor contract with the System Council U-13 of the IBEW. This contract, which runs through April 2024, defined an approximately 3.00 percent labor expense increase per year, and its effect is discussed in the testimony of Ms. Vesey.

Q. Have there been other increases in expenses since the last case?

A. Montana-Dakota has seen other increases to O&M expenses since the last case, such as subcontract labor. The maintenance expenses associated with the Thunder Spirit Wind Farm have increased approximately $360,000. In addition, the absence of certain transmission administration cost credits, received in 2018, resulted in an increase of $290,000.

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 2.98 percent based on plant in service as of December 31, 2020. The impact of the depreciation study results in a Montana electric jurisdiction increase of approximately $1.3 million in the revenue requirement, as compared to the previously approved rates.

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 post retirement benefits and cash working capital, net of the associated deferred taxes, to be added to rate base.

Q. Why has the Company proposed to include the post retirement regulatory assets in rate base at this time?

A. The cash contributions made by the Company have significantly exceeded the post retirement 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.

Due to post retirement annual expenses being reduced as they are recovered through the revenue requirement, this case reflects a negative cost of $300,000. This is a savings to customers and largely offsets the inclusion of the post retirement net assets.

The inclusion of post retirement is fully explained by Ms. Vesey.

Q. Has the Company added any other new adjustments to be considered?

A. Included in the settlement for Docket No. 2018.09.060, Montana-Dakota agreed to perform a Lead/Lag study and include the corresponding Cash Working Capital adjustment in its next electric rate case. Therefore, Montana-Dakota has included a Cash Working Capital adjustment that reduces the rate base by approximately $940,000. This adjustment reduces the revenue requirement by approximately $88,000.

This adjustment will be more fully explained by Mr. Adams and 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 $10.5 million increase in revenue is driven primarily by:

	Amount (in millions)
Rate Base	$2.3
O&M Expenses	2.0
Rate of Return	2.0
Property Taxes	2.0
Heskett Unit IV	1.4
Depreciation	0.7
Other	0.1
Net Increase	$10.5

The Heskett Unit IV addition is included in the Rate Base and represents approximately $1.4 million of the increase. Other plant additions, including the unamortized balance of the Lewis & Clark and Heskett coal units, represents another $2.3 million increase. Estimated Property Taxes are projected with an increase of approximately $2.0 million. Depreciation increases are a result of the updated Depreciation Study previously discussed, the Lewis & Clark Unit I and Heskett Unit I & II amortization, and other additions to rate base. These increases are partially offset by the Lewis & Clark Unit I and Heskett Unit I & II plant closures.

Q. How is the Accounting Deferral for Lewis & Clark Unit I and Heskett Unit I & II included in this case?

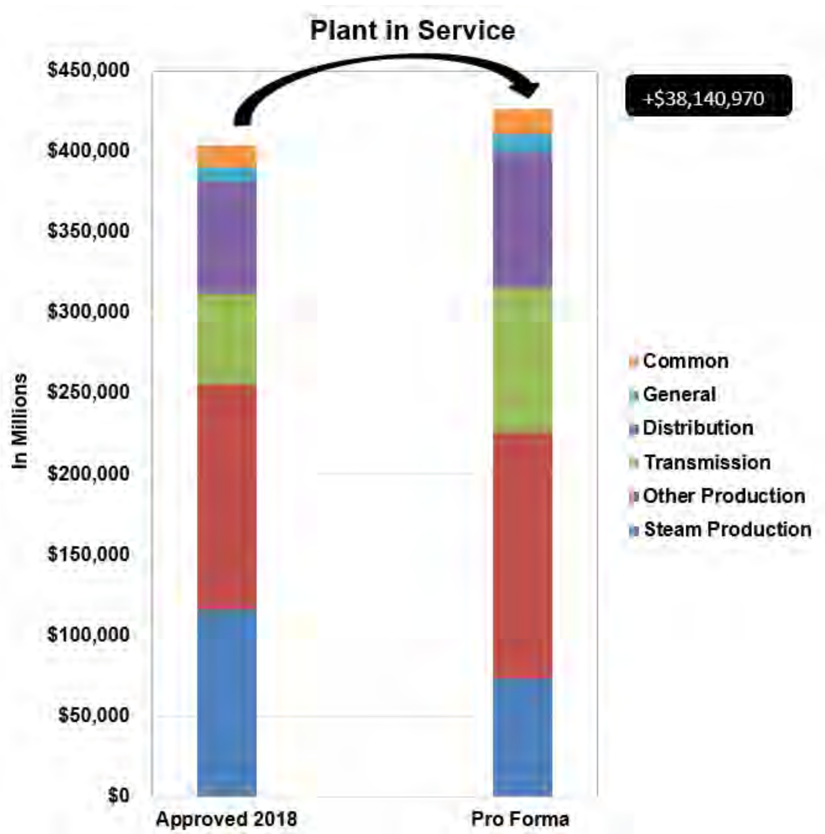
A In Docket No. 2019.11.086, Montana-Dakota received approval to defer accounting costs related to the closure of Lewis and Clark Unit I and Heskett Units I & II. The Company is now proposing the annual amortization of approximately $2 million per year, which will fully amortize these units in 10 years. This will be more fully discussed in the testimony of Mr. Jacobson.

Q. What incremental investments are included in this case as pro forma July 2022 – June 2023?

A. The Company has included incremental investments in July 2022 – June 2023 of approximately $38 million and are associated with the following investments:

- Production investments of approximately $23 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 $8 million including continued reliability upgrades necessary due to aging infrastructure, as discussed in greater detail by Mr. Frank;
- Distribution investment of approximately $4 million including service line replacements and upgrades required to maintain reliable service;
- General and common plant additions of approximately $3 million primarily associated with structures and improvements, work equipment, software systems such as the Outage Management System, as discussed in greater detail by Mr. Anderson.

The table below shows the investment in plant assigned and allocated to Montana electric operations from 2018 to pro forma July 2022 – June 2023.



Q. Montana-Dakota submitted its Integrated Resource Plan (IRP) on July 15, 2019. Attachment I of the 2019 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 million for the integrated system. In light of this request for additional revenue, have customers 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 the revenue requirement impact 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 Spring 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 2021 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, as further explained by Mr. Jacobson. Additionally, customers would have been paying higher overall rates in the meantime due to the variable costs of those plants that were included in the Fuel & Purchase Power Adjustment.

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 are as follows:

Rate Class	Overall Class Impact
Residential Service	19.2%
Small General Service	15.1%
Large General Service	12.9%
Municipal Pumping	15.4%
Lighting	10.3%
Total	15.2%

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

A. Montana-Dakota is requesting an overall return of 7.525 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 the Administrative Rules of Montana (ARM) § 38.5.5 Interim Utility Rate Increases. The amount of interim relief sought is $1,716,219 or 2.7 percent and consists of the Company's pro forma July 2022 – June 2023 revenue requirement. The Company's reported rate of return the last two years of 5.29 percent and 5.52 percent for its Montana electric operations support the need for interim rate relief while this rate case is being processed.

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. Is the Company seeking a change in any of the cost recovery mechanisms in this case?

A. Yes. The Fuel and Purchased Power Cost Adjustment currently includes charges through energy markets in the Regional Transmission Organizations (RTO's). The Company is proposing to expand the Fuel and Purchased Power Cost Tracking Adjustment Rate 58 to include the net transmission service costs providing access to RTO market energy as more fully explained by Mr. Neigum and Ms. Vesey.

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 who 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 Montana 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 for Montana-Dakota, 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 IRP and plant closure model. Mr. Neigum will also discuss the nexus between transmission service and other RTO costs currently recovered through the Fuel and Purchased Power Adjustment.
- Mr. Daryl Anderson, Director of Electric Distribution Services for Montana-Dakota, will testify regarding the Outage Management System.
- Mr. Larry E. Kennedy, Senior Vice President for Concentric Advisors, ULC., will testify regarding the depreciation study for Montana-Dakota's electric operations of the plant in service as of December June 31, 2020 that supports the proposed depreciation rates in this filing.
- Mr. Michael J. Adams, Senior Vice President for Concentric Energy Advisors, Inc., will testify regarding Montana-Dakota's lead lag study and cash working capital adjustment.

- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement and the interim revenue requirement.
- Mr. Travis R. Jacobson, Director of Regulatory Affairs for Montana-Dakota, will testify regarding the Lewis and Clark Unit I and Heskett Unit I & II retirements and the amortization of the remaining balances.
- Mr. Ron J. Amen, Managing Partner for Atrium Economics, LLC, will testify regarding Montana-Dakota's embedded class cost of service study and 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 Montana electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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 the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade, and Intermountain.

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

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have 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 F.

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 F?

A. Statement F shows the average utility capital structure of Montana-Dakota for the twelve months ended June 30, 2022 and the pro forma average capital structure for the twelve months ended June 30, 2023. Statement F includes the associated costs of 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 7.525 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.

Statement F, Rule 38.5.146 summarizes the average of the actual utility capital structure at June 30, 2022 and the pro forma average capital structure at June 30, 2023. As shown on page 1, the components of the June 30, 2023 pro forma overall annual rate of return, which are used by Ms. Vesey to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.075%
Short Term Debt	0.168%
Common Equity	5.282%
Required Rate of Return	7.525%

Page 2 of Rule 38.5.146 reflects the Company's utility common equity balance at June 30, 2022 and the pro forma balance at June 30, 2023. The changes to the common equity balances include the normal changes, including pro forma earnings.

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 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 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, in order to achieve and maintain the targeted capital structure, the Company expects to receive approximately $17.5 million of common equity during 2022 but does not project to need any equity in 2023.

In March 2021, the Company entered into a $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 via the issuance of long-term debt.

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 expecting to issue any additional long-term debt in 2022 or 2023.

Q. What does Statement F, Rule 38.5.147 show?

A. Page 1 is a summary showing the Company's long-term debt at June 30, 2022 and associated cost of debt, and it shows the pro forma long-term debt and associated costs as of June 30, 2023, as well as the average cost of debt for the two periods. Page 2 shows the cost and the debt balance by issue at June 30, 2022. Page 3 shows the pro forma cost and the debt balance by issue at June 30, 2023.

Q. How did you derive the pro forma cost of debt as of June 30, 2023?

A. The pro forma cost of debt as of June 30, 2023 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement F, Rule 38.5.147, page 4 and explain the amortization method utilized?

A. Page 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 unamortized loss becomes fully amortized in 2022.

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

A. Page 5 presents the average short-term debt balance as of June 30, 2022 and pro forma average short-term debt balance as of June 30, 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 using month-end balances.

Q. Why is the average cost of short-term debt expected to increase in 2023?

A. The average cost of short-term debt as of June 30, 2022 is 0.966% and is expected to increase to 4.621% by June 30, 2023. This increase is due to the Federal Reserve's action to slow down the rate of inflation by increasing the Fed Funds rate beginning in March of 2022. It is expected the Federal Reserve will have increased the Fed Funds rate from 0.25% at the beginning of 2022 to 4.00% by the end of 2022. Montana-Dakota's short-term borrowing rate closely tracks the Fed Funds rate. Although the average short-term debt cost is higher than the long-term debt cost, if Montana-Dakota were to issue long-term debt in 2023 the Company would expect those costs to be even higher, likely in the range of 5% to 5.5%.

Q. Please describe the remaining portion of Statement F.

A. Statement F includes Rule 38.5.148, 149-151, and 152. Montana-Dakota has reacquired all preferred stock, no longer has publicly traded common stock, and does not have first mortgage bonds outstanding. Therefore, each of the above noted Rules was addressed indicating such.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE MONTANA PUBLIC SERVICE COMMISSION
DOCKET NO. 2022.11.___
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 Montana 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 Montana ("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") 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 15, 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 several Cost of Equity ("COE") estimation methodologies including 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 Company's customer concentration; (2) the Company's small size; (3) Flotation Costs; (4) the Company's capital expenditure requirements; and (5) the regulatory environment in which the Company operates. Finally, I consider the Company's proposed capital structure as compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my COE 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.

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[1,2] 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. Because the Company's required ROE should be a forward-looking estimate, these analyses rely on forward-looking inputs and assumptions (e.g., projected analyst growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.)
- 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 COE estimation models produce a wide range of results. My conclusion as to the appropriate ROE for Montana-Dakota within that range of results 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

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[1] U.S. Supreme Court, *Bluefield Water works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923).

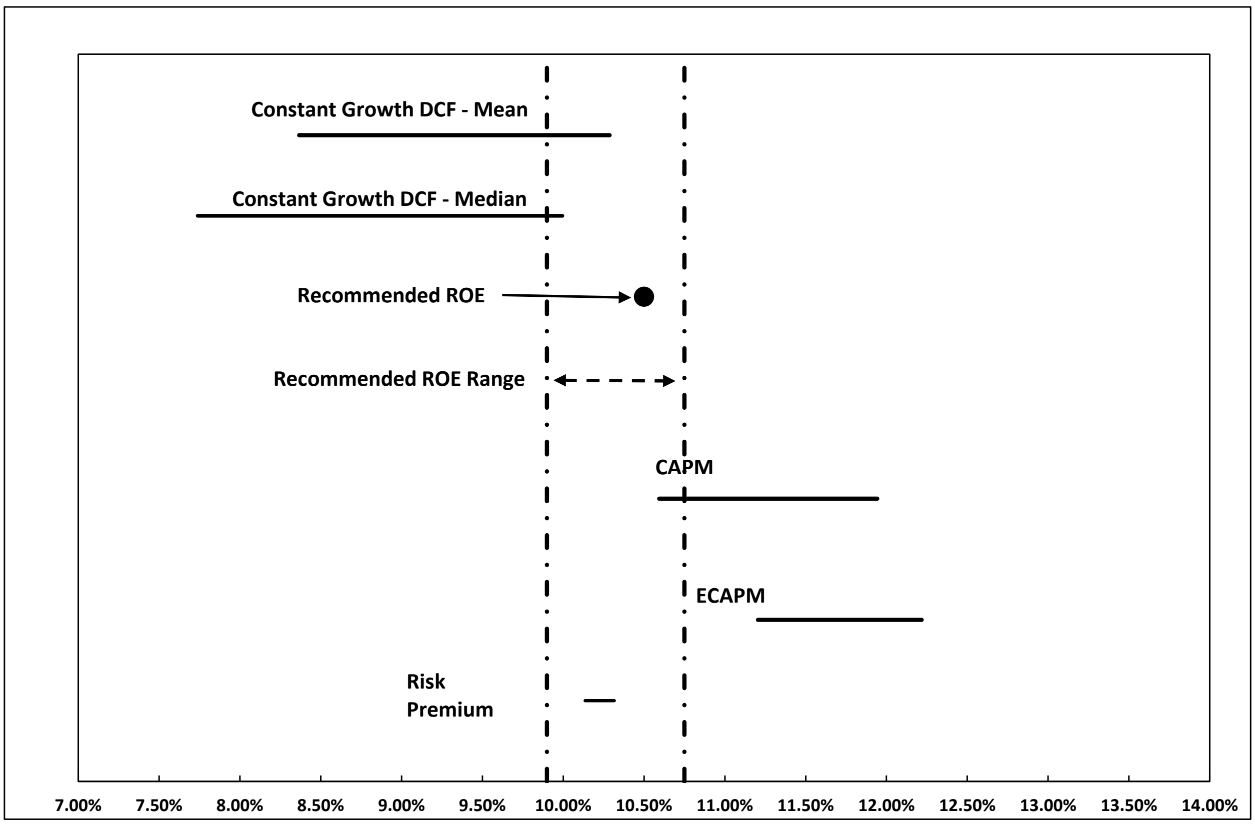
[2] U.S. Supreme Court, *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

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.

Q11. Please summarize the COE 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 COE 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 Montana relative to the proxy group, I believe a range of returns 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 Montana 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 50.30 percent common equity ratio is 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 15, the results of that analysis demonstrate that the average equity ratios for the utility operating companies of the proxy group range from 45.43 percent to 59.86 percent, with an average of 52.29 percent. Comparing the recommended equity ratio to the proxy group demonstrates that the Company's requested equity ratio is well within the range equity ratios 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.[3]

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.

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. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A15. Yes, it has. In Docket No. D2017.9.80 for Energy West Montana, Inc. ("EWM"), the Commission stated that:

> [t]he paradigm of utility regulation requires commissions to authorize ROEs commensurate with returns on alternative investments with similar risk. See Hope and Bluefield.[4]

Additionally, the Commission further noted that:

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[3] Hope, 320 U.S. 591 (1944); Bluefield, 262 U.S. 679 (1923).

[4] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 50.

> [t]he cost of equity is a vigorously contested issue in this proceeding, because unlike long-term debt which is priced based on transparent agreements between the utility and a third-party issuer, the cost of equity is estimated based on expectations of what equity investors demand in return for the time-value of their money and the risk of the investment at hand.[5]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Montana-Dakota to attract capital on reasonable terms.

Q16. Is fixing a fair rate of return just about protecting the utility's interests?

A16. 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]he rate-making process … involves balancing of the investor and consumer interests." Fed Power Commn. v. Hope Nat. Gas Co., 320 US 591, 603 (1944).

Q17. 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?

A17. 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

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[5] Id., at 39-40.

integrity. To the extent the Company has the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q18. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A18. 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 Montana.

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.

Q19. What are your conclusions regarding regulatory guidelines and capital market expectations?

A19. 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

Q20. Why is it important to analyze capital market conditions?

A20. The COE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the COE 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 analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the COE estimation models to estimate the required return for the subject company.

As a result, it is important to consider the effect of these conditions on the COE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the COE 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.

Q21. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A21. The COE for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: 1) persistently high inflation, 2) changes in monetary policy, and 3) rising long-term interest rates. These factors affect the assumptions used in the COE estimation models. In this section, I discuss each of these factors and how they affect the models used to estimate the cost of equity for regulated utilities.

Q22. What effect do current and prospective market conditions have on the COE for Montana-Dakota?

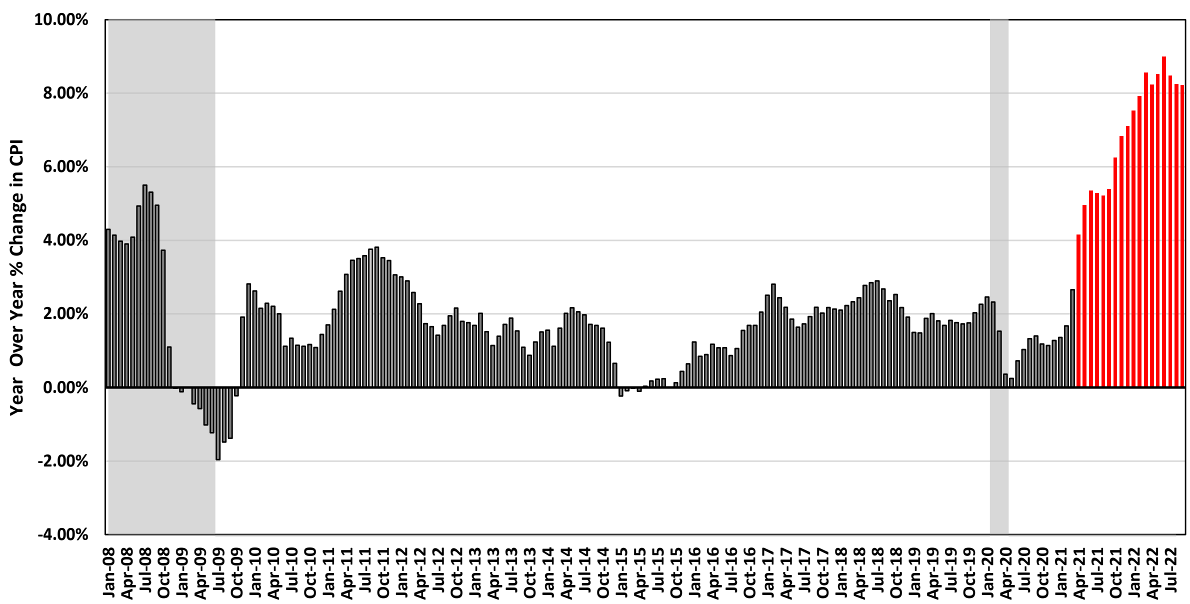
A22. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation, and the Federal Reserve's changes in monetary policy, contribute to an expectation of increased market risk and an increase in the investor-required return. It is essential that these factors be considered in setting a forward-looking cost of equity. Inflation has recently been at some of the highest levels seen in approximately 40 years. Interest rates, which have increased from the pandemic lows seen in 2020 are expected to continue to increase in direct response to the Federal Reserve's monetary policy. Since there is a strong historical inverse correlation between interest rates and the share prices of utility stocks (share prices of utility stocks typically fall when interest rates rise), it is reasonable to expect that investors' required COE for utility companies will also continue to increase. Therefore, COE estimates based solely on current market conditions will understate the COE required by investors during the future period that the Company's rates determined in this proceeding will be in effect.

A. Inflationary Expectations in Current and Project Capital Market Conditions

Q23. Has inflation increased significantly over the past year?

A23. Yes. As shown in Figure 2, the YOY change in the Consumer Price Index ("CPI") published by the Bureau of Labor statistics has increased steadily since the beginning of 2021, rising from 1.37 percent in January 2021. Since that time, and particularly since the start of 2022, inflation has increased steadily, reaching a high of 9.0 percent YOY change in June 2022, which was the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008, in September CPI decreased to 8.22 percent, which is still at levels not seen since the 1980s.

Figure 2: Price Index—YOY Percent Change January 2008–September 2022[6]



Q24. What are the expectations for inflation over the near-term?

A24. The expectation is that inflation will remain elevated over the near-term. This expectation is supported by recent comments of the Chair and Vice Chair of the Federal Reserve. For

6 Source: Bureau of Labor Statistics, shaded area indicates a recession.

example, in her speech on September 7, 2022 at the Clearing House and Bank Policy Institute 2022 Annual Conference, Vice Chair Lael Brainard noted that:

> **We are in this for as long as it takes to get inflation down.** So far, we have expeditiously raised the policy rate to the peak of the previous cycle, and the policy rate will need to rise further. As of this month, the maximum monthly reduction in the balance sheet will be nearly double the level of the previous cycle. Together, the increase in the policy rate and the reduction in the balance sheet should help bring demand into alignment with supply. **Monetary policy will need to be restrictive for some time to provide confidence that inflation is moving down to target.** The economic environment is highly uncertain, and the path of policy will be data dependent. While the precise course of action will depend on the evolution of the outlook, I am confident we will achieve a return to 2 percent inflation. Our resolve is firm, our goals are clear, and our tools are up to the task.[7]

Similarly, Chair Powell in his press conference at the Federal Open Market Committee meeting in September 2022 that:

> Inflation remains well above our 2 percent longer-run goal. … Price pressures remain evident across a broad range of goods and services. Although gasoline prices have turned down in recent months, they remain well above year-earlier levels, in part reflecting Russia's war against Ukraine, which has boosted prices for energy and food and has created additional upward pressure on inflation. The median projection in the SEP for total PCE inflation is 5.4 percent this year and falls to 2.8 percent next year, 2.3 percent in 2024, and 2 percent in 2025; participants continue to see risks to inflation as weighted to the upside.[8]

B. The Effect of Monetary Policy on Market Dynamics

Q25. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A25. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy

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7 Vice Chair Lael Brainard, "Bringing Inflation Down," Clearing House and Bank Policy Institute 2022 Annual Conference, September 7, 2022.

8 Transcript, Chair Powell, Press Conference, September 21, 2022.

programs used to mitigate the economic effects of COVID-19. As of the September 21, 2022 meeting, the Federal Reserve has taken the following actions:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[9]
- Increased the target federal funds rate beginning in March 2022 through a series of five increases from 0.00 – 0.25 percent to 3.00 percent to 3.25 percent;[10,11,12,13.]
- Anticipated the need to bring the Fed Funds rate to a restrictive level and keep it there for some time in order to achieve its goals of maximum employment at the inflation rate of 2 percent over the long-run;[14] and
- Began reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022.[15] The Federal Reserve is reducing the size of its balance sheet by only reinvesting principle payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury Securities, the cap is set at $60 billion per month. The cap for mortgage-backed securities is set at $35 billion per month.[16]

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q26. What effect will inflation and Federal Reserve's normalization of monetary policy have on long-term interest rates?

A26. 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

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9 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.

10 Federal Reserve, Press Release, March 16, 2022.

11 Federal Reserve, Press Release, May 4, 2022.

12 Federal Reserve, Press Release, June 15, 2022.

13 Federal Reserve, Press Release, September 21, 2022.

14 Transcript, Chair Powell, Press Conference, September 21, 2022.

15 Source: Federal Reserve, Press Release, May 4, 2022.

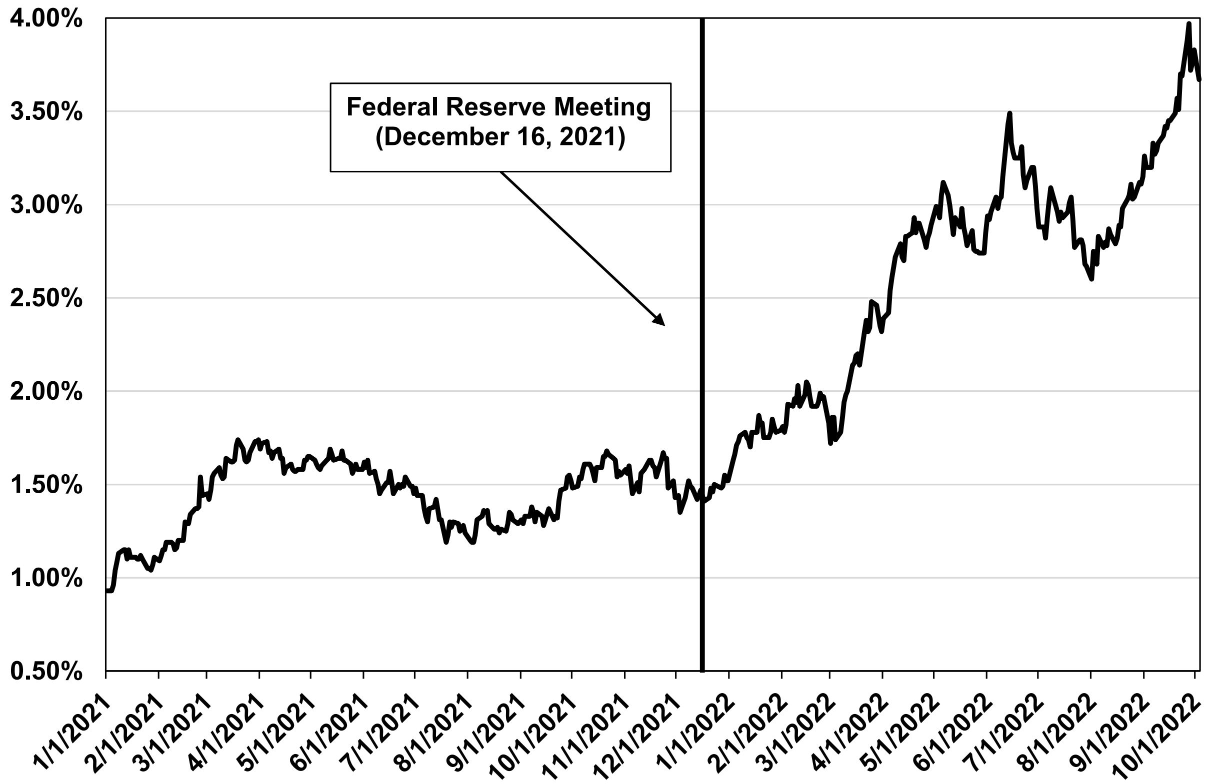
16 Source: Federal Reserve, Press Release, September 21, 2022.

increased levels of inflation, they will require higher yields to compensate for the increased risk of inflation, which means interest rates will increase.

Q27. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A27. Yes, they have. At the FOMC meetings throughout 2022, the Federal Reserve has continued to note its concerns over the sustained increased levels of inflation and has continued to accelerate the process of normalizing monetary policy to combat inflation. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bond has more than doubled, increasing from 1.47 percent on December 15, 2021 to 3.83 percent on September 30, 2022. The increase is due to the Federal Reserve's announcements at the each of the meetings since December 2021, 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 3: 10-Year Treasury Bond Yield—Janaury 2021– September 30, 2022[17]



Q28. Do recent changes in GDP affect the current outlook for inflation and interest rates?

A28. No. While FOMC participants have reduced their projections for economic activity for real GDP growth of 0.2 percent in 2022 and 1.2 percent in 2023, which is well below the median estimate for the longer-run normal GDP growth rate, the Fed has highlighted that the labor market continues to be extremely tight. Specifically, Chair Powell noted at the September 2022 FOMC meeting that unemployment remained near 50-year lows and job vacancies near historical highs. Therefore, with a tight labor market and persistently high

[17] S&P Capital IQ Pro.

inflation, the Fed has indicated its need to continue a restrictive monetary policy to moderate demand to better align it with supply.[18]

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q29. Are utility share prices correlated to changes in the yields on long-term government bonds?

A29. 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 utilities. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman 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).[19]

Q30. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A30. Equity analysts project that utilities will underperform the broader market as interest rates increase. Fidelity recently classified the utility sector as underweight[20] and Morningstar recently stated that a long as inflation persists the utility sector will underperform.[21] Specifically, Morningstar indicated that:

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18 Federal Reserve, Transcript of Chair Powell's Press Conference, September 21, 2022.

19 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.

20 Fidelity, "Top sectors to watch in Q3," August 3, 2022.

21 Miller, Travis, "As Long as Inflation Worries Persist, We Expect Utilities to Underperform: Renewable energy continues to be a long-term boon for the sector," July 6, 2022.

> [a]s long as inflation remains the market's top concern, we expect utilities to underperform. Utilities are the most sensitive to inflation because of their mostly fixed revenue, large capital investment budgets, and borrowing needs. We think long-term investors who want utilities in their portfolios should focus on those in constructive regulatory environments with the most protection from inflation.[22]

Additionally, the Wall Street Journal ("WSJ") recently noted in an article published on October 18, 2022 that the S&P Utilities Index was down 14 percent over the past month. The WSJ attributed the decline in the S&P Utilities Index to the recent increase in long-term treasury yields:

> A big draw of utility stocks has become less attractive as interest rates have climbed. Utility stocks are known for their sizable dividends, offering investors a regular stream of income. Companies in the S&P 500 utilities sector offer a dividend yield of 3.3%, among the highest payout percentages in the index, according to FactSet.
>
> But the outsize dividends of utility stocks are no match for climbing bond yields. The yield on the benchmark 10-year Treasury note finished above 4% on Monday for a second consecutive session. Friday marked the 10-year yield's first close above the 4% level since 2008 and 11 straight weeks of gains. Treasurys are viewed as essentially risk-free if held to maturity.
>
> "The 10-year is repricing everything. I've got something that's even safer and yields even more," said Kevin Barry, chief investment officer at Summit Financial, comparing Treasurys and utility stocks.[23]

Q31. Have you reviewed any market indicators that may imply that utilities will underperform over the near-term?

A31. Yes, I have. As discussed above, the utility sector is considered a "bond proxy" or a sector that investors view as a "safe haven" alternative to bonds, and changes in 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

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[22] *Ibid.*

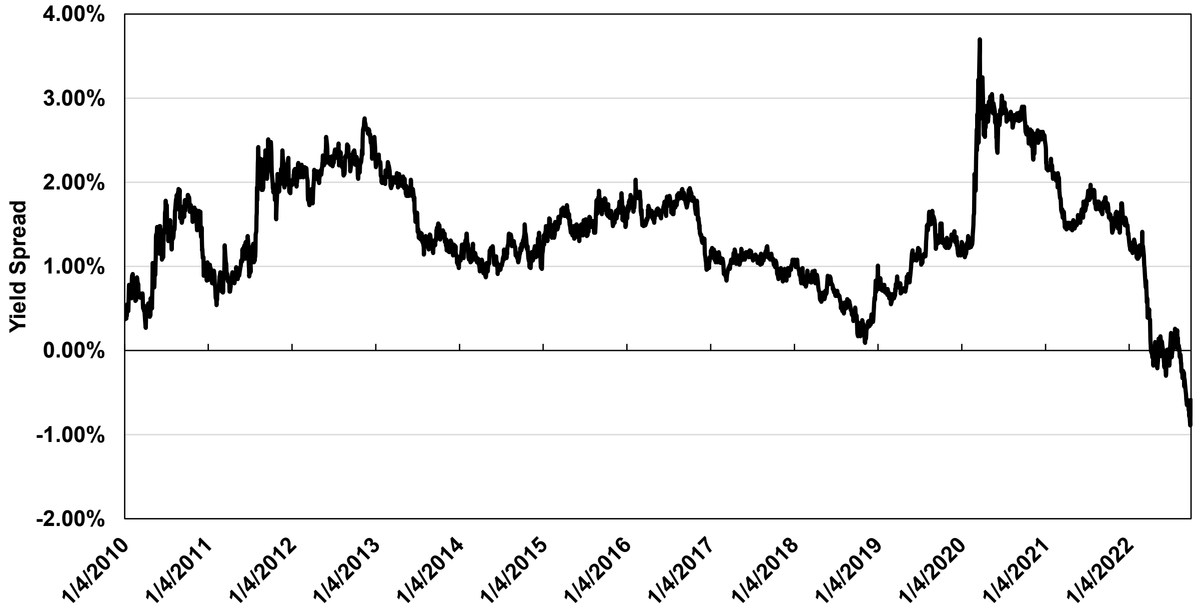
[23] Miao, Hannah, "Utility Stock stumble as treasury yields climb," The Wall Street Journal, October 18, 2022.

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 difference ("yield spread") between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through September 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 4ices of utilities.

Figure 4**: Yield Spread between the Dividend Yield on the S&P Utilities Index and the Yield on the 10-year Treasury Bond – January 2012 – September 2022**, the yield spread as of September 30, 2022, was -0.59 percent indicating that the yield on the 10-year Treasury Bond has exceeded the dividend yield for the S&P Utilities Index. Furthermore, the current yield spread of -0.59 percent is well below the long-term average since January 2010 of 1.41 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 most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds continue to increase, thus resulting in a decrease in the share prices of utilities.

Figure 4: Yield Spread between the Dividend Yield on the S&P Utilities Index and the Yield on the 10-year Treasury Bond – January 2012 – September 2022[24]



Q32. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A32. As discussed above, the Federal Reserve is currently normalizing monetary policy in response to inflation which actions are 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 5, below summarizes the effect of price on the dividend yield in the Constant Growth DCF model.

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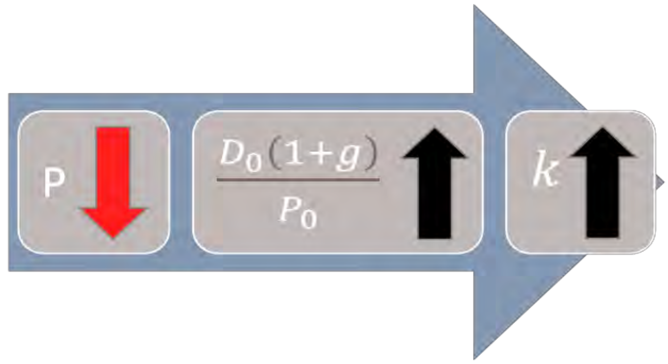
[24] S&P Capital IQ Pro and Bloomberg Professional.

Figure 5: 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 COE produced by the Constant Growth DCF model. Therefore, this expected change in market conditions supports consideration of the range of COE 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 COE 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.

Q33. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of high inflation and increasing interest rates?

A33. Yes. For example, in its May 2022 decision in establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") specifically concluded that the current capital market conditions of high inflation and increasing interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[25]
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[26]

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[25] *Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc.*, Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

[26] *Id.*, Opinion and Order, May 12, 2022, pp. 177–178.

E. Conclusion

Q34. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A34. 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 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 COE estimation models such as the CAPM and the ECAPM, which may more directly reflect expected market conditions.

V. PROXY GROUP SELECTION

Q35. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A35. 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 Montana 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.

Q36. Please provide a brief profile of Montana-Dakota.

A36. 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 provides electric service to approximately 25,500 customers in 30 communities in Montana.[27] As of June 30, 2022, the Company's net utility electric plant in Montana was approximately $253.18 million.[28] In addition, the Company had total electric sales in Montana in 2021 of approximately 746,634 MWh, composed of 24.41 percent residential, 15.40 percent commercial, 58.74 percent industrial and 1.45 percent other customers.[29] For the Company's parent entity, MDU Resources, Montana accounted for 22 percent of its total electric retail sales revenue in 2021, while North Dakota operations were 64 percent, South Dakota was 5 percent, and Wyoming was 9

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[27] Montana-Dakota Utilities Co. 2021 Annual Report to the Montana Public Service Commission, at Montana Customer Information, at 33.

[28] Data provided by Montana-Dakota Utilities Co.

[29] Montana-Dakota Utilities Co. 2021 Annual Report to the Montana Public Service Commission, at Montana Consumption and Revenues at 41.

percent.[30] 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[31].

Q37. How did you select the companies included in your proxy group?

A37. 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;
- 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.

Q38. Did you exclude any other companies from the proxy group?

A38. 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"). Further, the Value Line five-year projected EPS growth rates for this company

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30 MDU Resources Group, Inc., Form 2021 SEC Form 10-K at 12.
31 S&P and Fitch Ratings accessed September 30, 2022.

have fallen from 5.0 percent in July 2021, prior to the deliberations in the rate proceeding to "Nil" in October 2021 and most recently 0.5 percent in July 2022. Specifically, Value Line noted the following in PNW's July 2022 report:

> Untimely Pinnacle West stock is still seeking its equilibrium level after the regulatory blow the company suffered last year. From mid-2021, it became apparent that the company's utility (APS) wasn't going to get the rate relief it was seeking from its regulatory agency (ACC). APS and ACC staff were far apart on the size of their proposed increases, and the state's residential consumer office was seeking a large cut. When the rate decision arrived in November, Pinnacle West saw its allowed return on equity (ROE) reduced from 10% to 8.7% (one of the lowest in the U.S.), and its annual earning power cut by $0.90 a share. **PNW stock fell 30% (May to November) before exhibiting an impressive relief rally into April, finally giving much of that back with the broad market decline and the realization that restitution may be unlikely**.
>
> The utility has thus far been unsuccessful in its bid for a judiciary appeal. In December, APS filed a petition for special action with the Arizona Supreme Court, but was turned down. It also put in a request to argue its case before the state Court of Appeals but has had no response.[32]

Based on the fact that the assumptions used in the DCF model have been affected significantly by PNW's last rate decision, I have excluded PNW from my 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].[33]

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

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32 Value Line, Pinnacle West, July 22, 2022. (emphasis added)
33 Hawaii Electric Industries, Inc., 2021 Form 10-K, at 23.

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").[34] 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.[35] As a result, I have excluded HE from my proxy group considering HE's unique geographical risks.

Q39. What is the composition of your proxy group?

A39. 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 6 below:

Figure 6: 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
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE

[34] *Id.*, at 86.
[35] *Id.*, at 20.

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

Q40. Please briefly discuss the ROE in the context of the regulated rate of return.

A40. 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 COE is market-based and, therefore, must be estimated based on observable market data.

Q41. How is the required COE determined?

A41. While the cost of debt can be directly observed, the required COE is market-based and, therefore, must be estimated based on observable market information. The required COE 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.

Q42. What methods did you use to determine your recommended ROE in this proceeding?

A42. 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

Q43. Why is it important to use more than one analytical approach?

A43. Because the COE is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the COE, 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 COE, and I use multiple approaches to estimate the COE. As a practical matter, however, all of the models available for estimating the COE are subject to limiting assumptions or other methodologies constraints. Consequently, many well-regarded finance texts recommended using multiple approaches when estimating the COE. For example, Copeland, Koller, and Murrin[36] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[37] recommend the CAPM, DCF, and "bond yield plus risk premium" approaches.

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36 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.

37 Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

Q44. Do current market conditions support the use of more than one analytical approach?

A44. Yes. Interest rates have increased and are expected to continue to increase from the lows as a result of the COVID-19 pandemic. Given the inverse relationship between interest rates and utility share prices, the dividend yields of utilities are expected to increase over the near-term. Therefore, the current low dividend yields for utilities 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 through the use of projected interest rates. Therefore, it is important to use multiple analytical approaches to ensure that the COE results reflect the market conditions that are expected during the period that Company's rates will be in effect. Given the expectation that interest rates will increase, it is important to moderate the impact that the current lower interest rates are having on the COE 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.

Q45. Are you aware of any regulatory commissions that have recognized the importance of considering the results of multiple models?

A45. Yes, several regulatory commissions consider the results of multiple COE estimation methodologies such as the DCF, CAPM, and ECAPM in determining the authorized ROE, including the Minnesota Public Utilities Commission ("Minnesota PUC")[38], the Michigan Public Service Commission ("Michigan PSC")[39], the Iowa Utilities Board ("IUB")[40], the

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[38] 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.

[39] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

[40] Iowa Utilities Board, Iowa-American Water Company, RPU-2016-0002, Final Decision and Order issued February 27, 2017, at 35.

Washington Utilities and Transportation Commission ("Washington UTC")[41] and the New Jersey Board of Public Utilities ("NJBPU")[42]. 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."[43] 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."[44]

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.[45] The Commission also considered authorized ROEs in other states, increased volatility in capital markets and the company-specific business risks of DTE Gas.

Q46. Has the Commission recognized that it is important to consider the results of multiple models?

A46. Yes. It is my understanding that in its order for EWM, the Commission determined the authorized ROE for EWM based on variations of both the DCF and the ECAPM. Specifically, the Commission noted that:

> [t]he Commission calculates the allowed ROE as follows: (1) calculates the arithmetic mean of the three DCF results, (2) calculates the arithmetic

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41 *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).

42 NJBPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

43 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013).

44 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

45 Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

> mean of the two ECAPM analyses, (3) takes the results of the Commissions Modified ECAPM using a MRP of 9.19% and a β of .72 Supra ¶ 124. (4) calculates both the arithmetic and geometric means of the resulting figures from steps 1-3.[46]

While the Commission preferred the ECAPM model to the DCF model, the Commission relied on the DCF model as a check on the results of the ECAPM to ensure the COE results from the ECAPM model were consistent with investors' expectations.[47]

Q47. What are your conclusions about the results of the DCF and CAPM models?

A47. 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

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[46] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 46.

[47] *Ibid.*

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

Q48. Please describe the DCF approach.

A48. 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:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required COE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q49. What assumptions are required for the Constant Growth DCF model?

A49. 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.

Q50. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A50. 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 September 30, 2022.

Q51. Why did you use three averaging periods for stock prices?

A51. 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 COE 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.

Q52. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A52. 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.

Q53. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A53. 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.

Q54. What sources of long-term growth rates did you rely on in your Constant Growth DCF model?

A54. 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.

Q55. How did you calculate the expected dividend yield?

A55. 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.

Q56. How did you calculate the range of results for the Constant Growth DCF model?

A56. 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.

Q57. Please summarize the results of your Constant Growth DCF analyses.

A57. Figure 7 (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 September 30, 2022. The mean results range from 9.12 percent to 9.19 percent. The mean high results range from 10.14 percent to 10.21 percent. The median and median high results range from 9.22 percent to 9.35 percent and 9.99 percent to 10.01 percent respectively. While I also summarize the low DCF results, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider the low DCF results at this time.

Figure 7: Summary of Constant Growth DCF Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.05%	9.12%	10.14%
90-Day Average	8.09%	9.16%	10.18%
180-Day Average	8.12%	9.19%	10.21%
	Median Low	Median	Median High
30-Day Average	7.60%	9.22%	9.99%
90-Day Average	7.74%	9.28%	9.98%

180-Day Average	7.87%	9.35%	10.01%

Q58. What are your conclusions about the results of the Constant Growth DCF model?

A58. 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 COE estimation models.

C. Capital Asset Pricing Model

Q59. Please briefly describe the Capital Asset Pricing Model ("CAPM")

A59. 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 COE;

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:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \qquad [4]$$

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.

Q60. What risk-free rate did you use in your CAPM analysis?

A60. 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., 3.47 percent);[48] (2) the projected 30-year U.S. Treasury bond yield for Q1 2023 through Q1 2024 (i.e., 3.88 percent);[49] and (3) the projected 30-year U.S. Treasury bond yield for 2024 through 2028 (i.e., 3.80 percent).[50]

Q61. Would you place more weight on one of these scenarios?

A61. 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 rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q62. Has the Commission relied on projected long-term U.S. Treasury Bond yields as the estimate of the risk-free rate?

A62. Yes. In Docket No. D2017.9.80 for EWM, the Commission relied on a projection of the 30-year U.S. Treasury Bond yield as the estimate of the risk-free rate in the ECAPM which

48 Bloomberg, as of September 30, 2022
49 Blue Chip Financial Forecasts, Vol. 41, No. 4, September 1, 2022, at 2.
50 Blue Chip Financial Forecasts, Vol. 40, No. 12, June 1, 2022, at 14.

is the model the Commission placed primary reliance on to determine the authorized ROE for EWM.[51]

Q63. What beta coefficients did you use in your CAPM analysis?

A63. 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.

Q64. How did you estimate the Market Risk Premium in the CAPM?

A64. 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 1.98

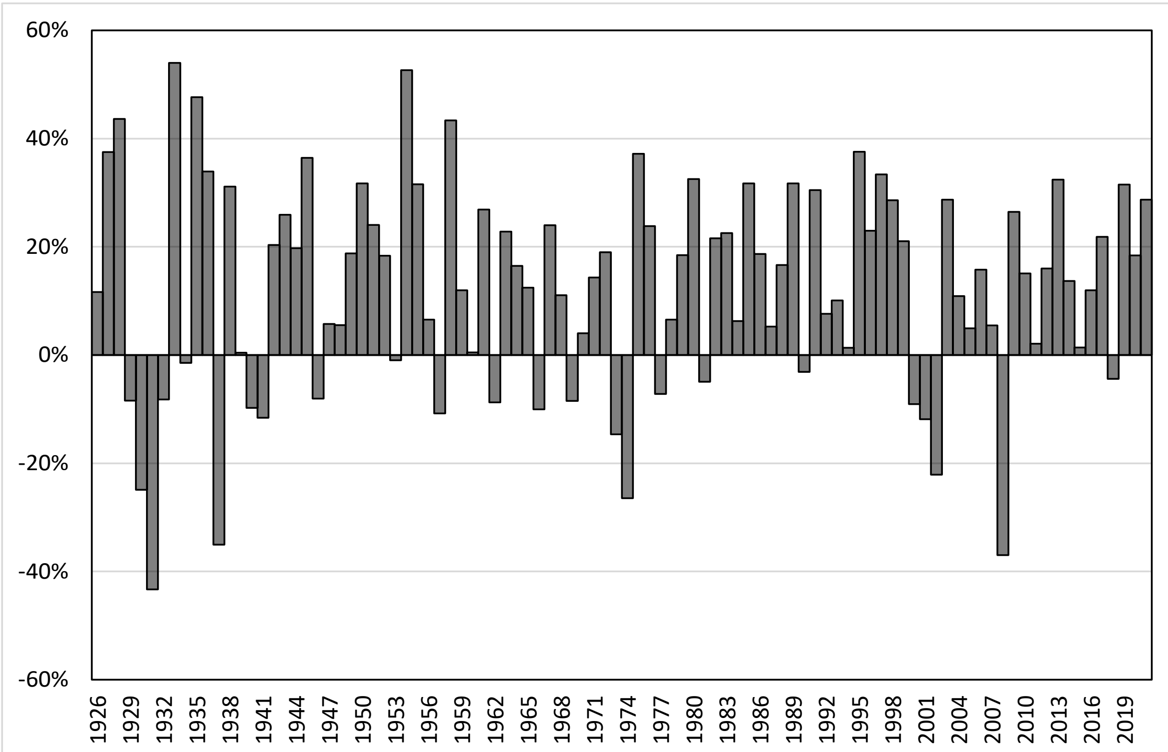
[51] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 42-43.

percent and a weighted long-term growth rate of 10.95 percent, the estimated required market return for the S&P 500 Index is 13.04 percent.

Q65. How does the current expected market return of 13.04 percent compare to observed historical market returns?

A65. Given the range of annual equity returns that have been observed over the past 96 years (shown in Figure 8 below), a current expected return of 13.04 percent is not unreasonable. In 50 of the past 96 years (i.e., in approximately 52 percent of all observations), the realized total equity return was at least 13.04 percent or greater.

Figure 8: Realized U.S. Equity Market Returns (1926-2021)[52]



Q66. Did you consider another form of the CAPM in your analysis?

A66. Yes. I have also considered the results of an Empirical CAPM ("ECAPM" or alternatively referred to as the Zero-Beta CAPM)[53] in estimating the cost of equity for Montana-Dakota. The ECAPM calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Where:

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52 Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook.

53 See e.g., Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

k_e = the required market COE

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.[54]

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.

Q67. Has the Commission relied on the ECAPM analysis?

A67. Yes. As noted above, in Docket No. D2017.9.80 for EWM, the Commission placed primary reliance on the results of the ECAPM and incorporated the results of the DCF analysis as a check on the ECAPM results to ensure the ECAPM did not produce results

[54] *Id.*, at 191.

that differed wildly from investor's expected returns.[55] Further, in regard to the use of adjusted Beta coefficients in the ECAPM, the Commission noted the following:

> Hill asserts that the use of the ECAPM with the use of adjusted betas is inappropriate as both serve to lower the slope of the Capital Market Line. Test. Hill 65. However, the Commission is persuaded by Morin's representation that "[t]he ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks." See Morin, Roger A. "Chapter 6: Alternative Asset Pricing Models." New Regulatory Finance Vienna: Public Utilities Reports, Inc. 2006.191. The Commission agrees with Scheig that the issue should be remedied by adopting the ECAPM, including his x factor of 0.25, which is intended to approximate the α effect identified by the academic literature reviewed in Morin's textbook.[56]

Q68. What are the results of your CAPM analyses?

A68. As shown in Figure 9 (see also Exhibit No. ___(AEB-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.59 percent to 11.94 percent. The ECAPM analysis results range from 11.21 percent to 12.22 percent.

Figure 9: 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	11.89%	11.94%	11.93%
Bloomberg Beta	11.32%	11.40%	11.38%
Long-term Avg. Beta	10.59%	10.70%	10.68%
ECAPM			
Value Line Beta	12.18%	12.22%	12.21%
Bloomberg Beta	11.75%	11.81%	11.80%
Long-term Avg. Beta	11.21%	11.29%	11.27%

[55] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 46.

[56] *Id.*, at 42.

D. Bond Yield Plus Risk Premium Analysis

Q69. Please describe the Bond Yield Plus Risk Premium approach.

A69. 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.

Q70. Are there other considerations that should be addressed in conducting this analysis?

A70. 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]

Q71. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A71. 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.

Q72. What did your Bond Yield Plus Risk Premium analysis reveal?

A72. As shown in Figure 10 below, from 1992 through September 30, 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

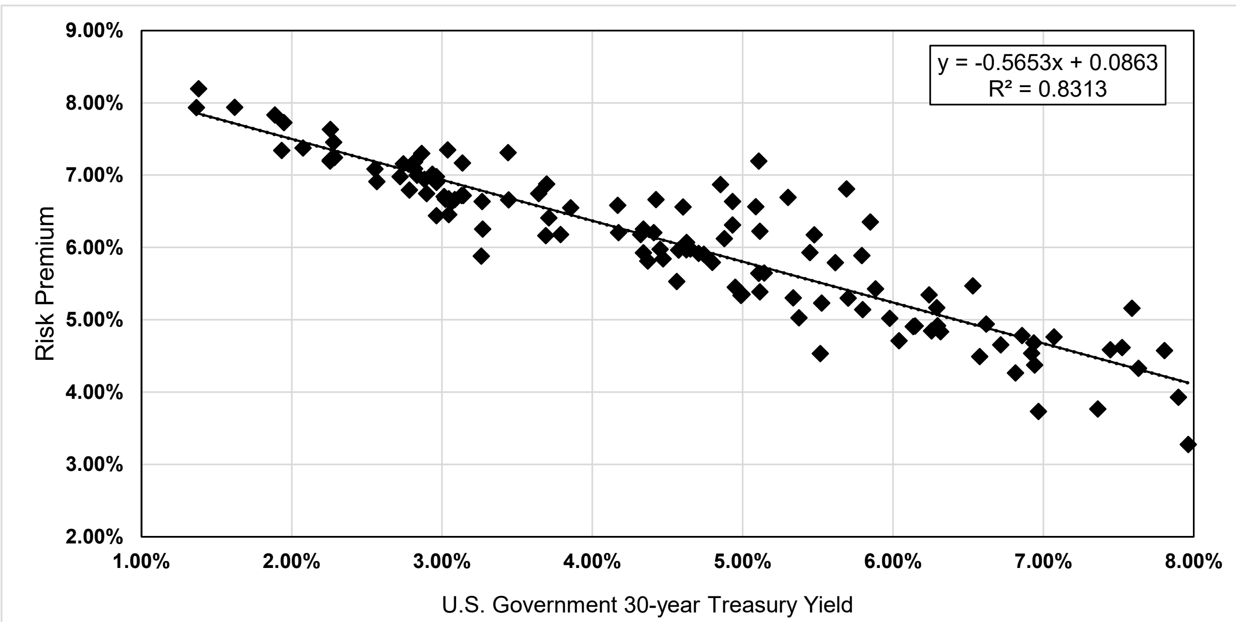
b = slope term

[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.

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 686 vertically integrated electric utility rate cases from 1992 through September 2022 as reported by Regulatory Research Associates ("RRA").[58] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 10: 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., 3.47 percent), the risk premium would be 6.67 percent, resulting in an estimated ROE of 10.14 percent. Based on the near-term (Q1 2023–Q1 2024) projections of the 30-year U.S. Treasury bond yield (i.e., 3.88 percent), the risk premium would be 6.44 percent, resulting in an estimated ROE of 10.32 percent. Based on longer-term (2024-2028) projections of the 30-year U.S. Treasury bond yield (i.e., 3.80

[58] This analysis began with a total of 1,401 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 686 cases.

percent), the risk premium would be 6.48 percent, resulting in an estimated ROE of 10.28 percent.

Q73. How did the results of the Bond Yield Risk Premium inform your recommended ROE for Montana-Dakota?

A73. 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.

E. Commission's ROE Methodology in Docket D2017.9.80 for Energy West Montana

Q74. Please describe the Commission's approach to determine the authorized ROE in its recent order for Energy West Montana ("EWM").

A74. As discussed above, the Commission developed a formula to calculate the COE based on the results of various specifications of the DCF model and ECAPM using market data provided by EWM in the case.[59] Specifically, to calculate the COE, the Commission calculated the average of the Constant Growth DCF analyses using earnings growth rate estimates from Value Line, Zacks and Bloomberg. The Commission also calculated the average of the ECAPM analyses using a historical market risk premium and Beta

[59] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 46-47.

coefficient estimates from Value Line and Bloomberg. In addition, the Commission also relied on a version of the ECAPM analysis using a forward-looking market risk premium and Beta coefficients from Value Line. Finally, the Commission calculated the arithmetic and geometric averages of the average DCF result, the average ECAPM result using a historical market risk premium and the ECAPM result using a forward-looking market risk premium. The resulting arithmetic and geometric averages were used to determine the authorized ROE for EWM.

Q75. How does your ROE recommendation compare with the return that would be derived using the Commission's approach of averaging the results of the DCF and ECAPM analyses to estimate the COE?

A75. While I continue to believe that it is also important to rely on the results of the Risk Premium analysis, I did calculate the resulting COE using the Commission's methodology in its recent order for EWM. The Commission's methodology is calculated by averaging the results of the Constant Growth DCF analysis and the ECAPM analysis. As shown in Figure 11 below, I calculated the average of my median Constant Growth DCF results using the 30-, 90- and 180-day stock price averaging periods. I also calculated the average of my ECAPM results which were estimated using a forward-looking market risk premium, Value Line, Bloomberg and long-term average Beta coefficients and current and projected interest rates. As shown in Figure 11, based on the Commission methodology, the COE calculated as the average of the DCF and ECAPM results is 10.52 percent. This demonstrates that my ROE recommendation of 10.50 percent is in line with the COE estimated using the averaging convention relied on by the Commission in its order for EWM.

Figure 11: Summary of the Commission's Methodology in Docket D2017.9.80 for EWM

Model	COE Estimate
Constant Growth Discounted Cash Flow (Average Earnings Growth Estimate):	
30-day Average Price	9.22%
90-day Average Price	9.28%
180-day Average Price	9.35%
Average	**9.28%**
ECAPM (Forward-looking Market Risk Premium):	
Value Line Beta Coefficient:	
Current Risk-Free Rate	12.18%
2023Q1–2024Q1 Projected Risk-Free Rate	12.22%
2024-2028 Projected Risk-Free Rate	12.21%
Bloomberg Beta Coefficient:	
Current Risk-Free Rate	11.75%
2023Q1–2024Q1 Projected Risk-Free Rate	11.81%
2024-2028 Projected Risk-Free Rate	11.80%
Long-Term Average Beta Coefficient:	
Current Risk-Free Rate	11.21%
2023Q1–2024Q1 Projected Risk-Free Rate	11.29%
2024-2028 Projected Risk-Free Rate	11.27%
Average	**11.75%**
Average COE	**10.52%**

Q76. Has the Commission issued an order since its decision in Docket D2017.9.80 for EWM?

A76. Yes. The Commission issued an order in Docket D2018.2.12 for Northwestern Energy on December 19, 2019.

Q77. How did the Commission determine the authorized ROE for Northwestern Energy in Docket D2018.2.12?

A77. In Docket D2018.2.12, the parties in the case filed a partial settlement on May 10, 2019 which specified that the parties had agreed to an ROE for Northwestern Energy of 9.65 percent. Therefore, the Commission in its order on December 20, 2019, considered the reasonableness of the agreed to ROE of 9.65 percent. To evaluate the reasonableness of the parties' proposed 9.65 percent ROE, the Commission considered the initial recommendations of each of the parties in the case as well as the model results that were provided by each witness in support of their recommendation.[60] Thus, the Commission consider the results produced by models such as the DCF, CAPM, ECAPM, Rick Premium and Expected Earnings.[61] Based on its review of the models results and recommendations, the Commission concluded that a fair and reasonable ROE for Northwestern Energy would fall in the range of 9.2 percent to 10.0 percent and thus concluded that the parties' proposed ROE of 9.65 percent was reasonable.[62] Therefore, in the case for Northwestern Energy, the Commission considered the results of each of the COE estimation models presented by the parties as opposed to only relying on the DCF and the ECAPM results as it did when determined the authorized ROE for EWN in Docket D2017.9.80.

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60 Docket No. D2018.2.12, Order No. 7604u, IN THE MATTER OF NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design (Dec. 20, 2019), at 17-21.

61 *Id.,* at 18.

62 *Id.,* at 21.

Q78. Is the approach you have relied on to determine your recommended ROE of 10.50 percent for Montana-Dakota consistent with the Commission's approach in Docket D2018.2.12 for Northwestern Energy?

A78. Yes, it is. The Commission considered the results of each of the COE estimation methodologies provided in Docket D2018.2.12 to determine a range of reasonableness of 9.20 percent to 10.0 percent for Northwestern Energy. Similarly, as discussed above, in the current proceeding, I considered the range of results produced by my DCF, CAPM, ECAPM and Risk Premium analyses as well as current and prospective market conditions and the relative business and financial risk of Montana-Dakota to the proxy group in first determining my recommended ROE range of 9.75 percent to 10.75 percent and then ultimately my recommended ROE of 10.50 percent.

VII. REGULATORY AND BUSINESS RISKS

Q79. Do the DCF, CAPM, and ECAPM results for the proxy group, taken alone, provide an appropriate estimate of the COE for Montana-Dakota?

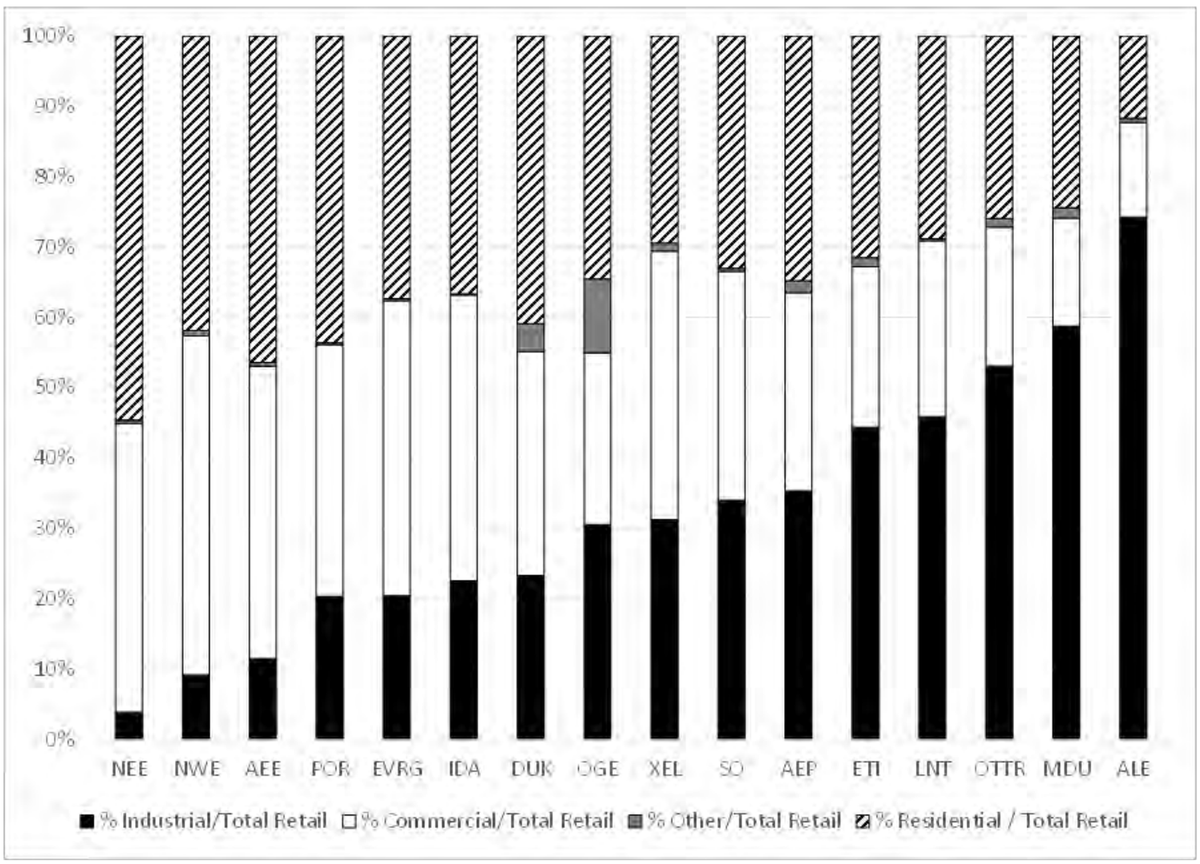
A79. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Customer Concentration

Q80. Please summarize Montana-Dakota's customer concentration risk.

A80. Approximately 60 percent of Montana-Dakota's 2021 total retail electric sales in Montana were derived from industrial customers. As shown in Figure 12, Montana-Dakota's commercial and industrial sales volume as a percentage of total retail electric sales was 75 percent, which is higher than all but one of the companies in the proxy group.[63]

Figure 12: Summary: Customer Concentration[64]



[63] Does not include "other" or residential customers.
[64] 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.

Q81. How does customer concentration and the Company's service territory affect business risk?

A81. 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 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).[65]

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

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[65] 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.

a more concentrated customer base will have the effect of increasing a company's cost of equity.[66]

Q82. Please describe how changes in economic conditions and the interdependent nature of Montana-Dakota's service territory can affect its business risk?

A82. Montana-Dakota is unique in that unlike most electric and natural gas utilities, the Company is dependent on a single customer for a large portion of its electric sales in Montana. The customer is engaged in oil and natural gas exploration and production. It is well-documented that the oil and natural gas production industry is very cyclical and may be undergoing changes as a result of green initiatives across the country. Additionally, like other industries, the oil and natural gas production industry is also dependent on the general business cycle. As a result, the customer's production could change based on general or industry specific economic conditions thereby impacting the customer's energy consumption.

Furthermore, Montana-Dakota is also in direct competition with other sources of energy such as natural gas, diesel, solar and wind among others. This creates an additional risk that customers in the commercial and industrial classes could install onsite generation to serve a substantial portion of their energy needs. For Montana-Dakota, the risk is much greater since the Company depends on a single customer for a substantial portion of sales.

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[66] *Id.,* at 4.

Q83. How dependent is Montana-Dakota's electric volume on the customer engaged in oil and natural gas production?

A83. The customer represents 29.85 percent of the Company's retail electric sales in Montana.[67] Therefore, if the customer were to decrease production as a result of fluctuations in the price of oil and natural gas or install onsite generation to serve its energy needs, Montana-Dakota could experience a significant decrease in electric sales. Furthermore, if the customer were to reduce output due to decreases in oil prices, the effect on the Montana-Dakota system could be compounded if reduced production affected the local economy. Thus, Montana-Dakota's reliance on a single large customer's load results in increased risk with respect to sales, earnings, and cash flow.

Q84. What is your conclusion regarding the Company's customer concentration and its effect on the cost of equity for Montana-Dakota's electric operations in Montana?

A84. Montana-Dakota is heavily reliant on sales to commercial and industrial customers. As noted above, 75 percent of Montana-Dakota's total retail electric sales in Montana were to commercial and industrial customers. This concentration is higher than all but one of the proxy group companies. In addition, 29.85 percent of Montana-Dakota's electric retail sales are to one customer. A high degree of customer concentration increases Montana-Dakota's risk related to competition from alternative energy sources and economic conditions. Increased customer diversity decreases the effect that any one customer can have on a company's sales. Thus, Montana-Dakota's heavy customer concentration implies

[67] Data provided by Montana-Dakota Utilities Co.

that the Company has an above average risk profile when compared to the companies in the proxy group.

B. Small Size Risk

Q85. Please explain the risk associated with small size.

A85. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect". While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[68]

Q86. How does the smaller size of a utility affect its business risk?

A86. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition

[68] Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q87. How does Montana-Dakota's electric operations in Montana compare in size to the companies in the Initial Proxy Group?

A87. Montana-Dakota's electric operations in Montana are substantially smaller than the median for the companies in my proxy group in terms of market capitalization. Exhibit No.___(AEB-2), Schedule 9 provides the actual market capitalization for the companies in my proxy group and estimates the implied market capitalization for Montana-Dakota (i.e., the implied market capitalization if Montana-Dakota's electric operations in Montana were a stand-alone publicly-traded entity). To estimate the size of the Company's market capitalization relative to the proxy group, I calculated Montana-Dakota's proposed capital structure equity component of $124.24 million by multiplying Montana-Dakota's test year rate base of $247 million by Montana-Dakota's test year common equity ratio of 50.30 percent. I then applied the median market-to-book ratio for the proxy group of 2.04 to Montana-Dakota's implied common equity balance and arrived at an implied market capitalization of approximately $253.23 million, or 1.63 percent of the median market capitalization for the proxy group.

Q88. How did you estimate the size premium for Montana-Dakota?

A88. Given this relative size information, it is possible to estimate the impact of size on the ROE for Montana-Dakota using *Kroll* data that estimates the stock risk premia based on the size of a company's market capitalization. As shown in Exhibit No.___(AEB-2), Schedule 9, the median market capitalization of the proxy group of approximately $15.54 billion corresponds to the third decile of the *Kroll* market capitalization data. Based on *Kroll*'s analysis, that decile corresponds to a size premium of 0.55 percent (i.e., 55 basis points). Montana-Dakota's implied market capitalization of approximately $253.23 million falls within the tenth decile, which comprises market capitalization levels up to $289.01 million and corresponds to a size premium of 4.80 percent (i.e., 480 basis points). The difference between those size premia is 425 basis points (i.e., 4.80 percent minus 0.55 percent).

Q89. Has the Commission recently considered the small size risk premium?

A89. Yes. In Docket D2017.9.80 for EWM, the Commission considered the evidence presented by EWM concerning an adjustment to the authorized ROE for small size risk. However, the Commission rejected the proposed small size risk premium due to the following reasons:[69]

- EWM did not show that the COE results did not already include a size premium given that the companies in the proxy group are made up of numerous smaller operating subsidiaries.
- A smaller firm should have a higher Beta coefficient due to the additional risk associated with the firm's small size; however, the Commission noted that this relationship did not hold with the companies contained in the proxy group used to estimate the COE for EWM;

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[69] Docket No. D2017.9.80, Order No. 7575c, IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Rates for Energy West Montana, Inc. and Cut Bank Gas Company (Sep. 26, 2018), at 51-53.

- The Commission agreed with the Montana Consumer Counsel that the small size risk premium for the broader market could not be seamlessly applied to the regulated utility industry; and

- The Commission reasoned that EWM did not provide enough detail to show how the company arrived at the estimated small size risk premium.

While the Commission rejected the small size risk premium in the rate case for EWM, the Commission indicated that it would be open to reviewing small size risk premium proposals in future cases. The Commission reasoned that for a small size risk premium an applicant must show that the small size effect is applicable to the regulated utility industry and that the COE results based on the companies in the proxy group did not already contain a small size risk premium.[70]

Q90. Have you considered the Commission's criteria for a small size risk premium?

A90. Yes, I have. One of the reasons the Commission rejected the small size risk premium in the EWM rate case was that the smallest companies in the proxy group did not necessarily have the highest Beta coefficients which would indicate greater risk. However, there are two important reasons why a smaller company may not always have the highest Beta coefficient. First, smaller companies are traded more infrequently than larger companies. A lower trading frequency can bias the estimate of the Beta coefficient. As Thomas Zepp notes in his article "Utility stocks and the size effect – revisited":

> Roll (1980) concluded trading infrequency seems to be a powerful cause of bias in beta risk estimates when time intervals of a month or less are used to estimate betas for small stocks. When a small stock is thinly

[70] *Id.*, at 53.

> traded, its stock price does not reflect the movement of the market, which drives down the apparent covariance with the market and creates an artificially low beta estimate.[71]

In fact, Zepp showed that Beta coefficients for a sample of water companies were greater when annual data (i.e., the approach employed by Ibbotson Associates) was used to estimate the Beta coefficient than the Beta coefficients reported by Value Line which use weekly data.[72]

Second, the Beta coefficients for small companies do not account for all of the risk associated with a company's small size. For example, Figure 13 contains the average Beta coefficient, average arithmetic annual return and average annual standard deviation for the companies included in each size decile developed by *Kroll*. As shown in Figure 13, the average annual arithmetic return for the tenth decile (i.e., the decile in which Montana-Dakota would be classified) was 20.04 percent. This equates to an equity risk premium of 15.17 percent if the long-term income only return of 4.87 percent from long-term government bonds is subtracted from the total annual return. Conversely, we could also estimate the equity risk premium using the Beta coefficient for the tenth decile and the historical market risk premium as report by *Kroll* from 1926-2021. If we multiply the historical market risk premium as reported by *Kroll* of 7.46 percent[73] by the Beta coefficient for the tenth decile of 1.39, the resulting equity risk premium is 10.37 percent. Thus, calculating the equity risk premium using the Beta coefficient significantly

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[71] Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." *The Quarterly Review of Economics and Finance*, vol. 43, no. 3, 2003, pp. 578–582., doi:10.1016/s1062-9769(02)00172-2.

[72] *Ibid.*

[73] The market risk premium from 1926-2021 is calculated as the average return on large company stocks from 1926-2021 minus the average income only return on long-term government bonds from 1926-2021 (i.e., 12.34 percent – 4.87 percent = 7.46 percent). Source: Kroll, 2022 SBBI Yearbook.

understates the actual long-term equity risk premium for companies contained in the tenth decile. Therefore, the Beta coefficient does not appropriately account for the additional risk associated with small size.

Figure 13: Kroll – CRSP Deciles Size Study as of December 31, 2021[74]

Decile	Beta	Annual Arithmetic Mean Return	Annual Standard Deviation of Returns
1 – Largest	0.92	11.54%	18.74%
2	1.04	13.04%	21.13%
3	1.11	13.68%	22.94%
4	1.13	13.82%	25.05%
5	1.17	14.47%	25.65%
6	1.18	14.83%	26.58%
7	1.25	15.51%	28.46%
8	1.30	15.80%	32.20%
9	1.34	16.93%	36.30%
10 - Smallest	1.39	20.04%	41.47%

Q91. Were utility companies included in the size premium study conducted by Duff and Phelps?

A91. Yes. In fact, as shown in Exhibit 7.2 of Kroll's 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile.[75] Therefore, Kroll did include utility companies in its size risk premium study.

Q92. Is the size premium applicable to companies in regulated industries?

A92. Yes, it is. For example, returning to Thomas Zepp's article "Utility stocks and the size effect – revisited" referenced above, Zepp provided the results of two studies which showed evidence of the required risk premium for small water utilities. The first study conducted by the California Public Utilities Commission Staff ("CPUC Staff") computed

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[74] Source: Kroll, Cost of Capital Navigator, CRSP Deciles Size Study – Supplementary Data Exhibits.

[75] Source: Kroll, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

proxies for Beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[76] The second study referenced by Zepp examined the differences in required returns over the period of 1987-1997 for two large and two small water utilities in California. As Zepp showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities. [77]

Additionally, Stéphane Chrétien and Frank Coggins in the article "Cost of Equity for Energy Utilities: Beyond the CAPM",[78] recently studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of natural gas utilities. The article considered the CAPM, the Fama-French three-factor model and a model similar to the ECAPM that I have also considered above. In the article, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins show the Beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[79] These two studies demonstrate that the size premium is evident in market data and is clearly applicable to regulated utilities.

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[76] Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." *The Quarterly Review of Economics and Finance*, vol. 43, no. 3, 2003, pp. 578–582., doi:10.1016/s1062-9769(02)00172-2.

[77] *Ibid.*

[78] Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531.

[79] Chrétien, Stéphane, and Frank Coggins. "Cost of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531.

Q93. Have regulators in other jurisdictions made a specific risk adjustment to the COE results based on a company's small size?

A93. Yes. In Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of COE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[80] Thus, the RCA awarded AEL&P an ROE of 12.875 percent which was 108 basis points above the highest return on equity estimate from any model presented in the case.[81] Similarly, in Order No. 19, the RCA noted that small size as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions increased the risk of ENSTAR Natural Gas Company.[82] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[83]

Additionally, in Docket No. E017/GR-15-1033 for Otter Tail Power Company ("Otter Tail"), the Minnesota Public Utilities Commission ("Minnesota PUC") selected an ROE

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80 Docket No. U-10-29, In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company, Order entered September 2, 2011 (Order No. 15) at 37.

81 *Id.*, at 32 and 37.

82 Docket No. U-16-066, In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of Semco Energy, Inc., Order entered September 22, 2017 (Order No. 19) at 50-52.

83 Ibid.

above the mean DCF results, as a result of multiple factors including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[84]

Finally, in Opinion No. 569 and 569-A, the FERC has relied on a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[85,86]

Q94. How have you considered the smaller size of Montana-Dakota in your recommendation?

A94. While I have estimated the effect of Montana-Dakota's small size on the ROE, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of Montana-Dakota's electric operations in Montana in the determination of where, within the range of analytical results, the Company's required ROE falls. Therefore, the additional risk associated with small size indicates that the Company's ROE should be established above the mean/median results for the companies in my proxy group.

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[84] Order in Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (August 16, 2016) at 55.

[85] Federal Energy Regulatory Commission, Opinion No. 569-A, May 21, 2020, at para 75.

[86] The U.S. Court of Appeals recently vacated the FERC Order 569 decisions that related to its risk premium model and remanded the case to FERC to reopen proceedings. However, in that decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20.

C. Flotation Cost

Q95. What are flotation costs?

A95. 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.

Q96. Why is it important to consider flotation costs in the allowed ROE?

A96. 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.

Q97. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A97. 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.

Q98. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A98. 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.

Q99. Is the date of MDU Resources' last issued common equity important in the determination of flotation costs?

A99. 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.

Q100. Is the need to consider flotation costs recognized by the academic and financial communities?

A100. 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.[87]

Q101. How did you calculate the flotation costs for MDU Resources?

A101. 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

[87] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

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).

Q102. Do your final results include an adjustment for flotation cost recovery?

A102. 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.

D. Capital Expenditures

Q103. Please summarize the projected capital expenditure requirements for Montana-Dakota.

A103. The capital expenditure projections for Montana-Dakota are approximately $158.6 million for the period from 2023 through 2027.[88] These investments relate predominantly to replacement of aging transmission infrastructure and are required to provide safe and reliable service. Based on the Company's net utility plant of approximately $253.2 million as of December 31, 2021, the anticipated capital expenditures represent approximately 62.66 percent of Company's net utility plant as of December 31, 2021.

Q104. How are the Company's risk profile affected by their substantial capital expenditure requirements?

A104. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the

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[88] Data provided by Montana-Dakota Utilities Co. for Capital Expenditures 2023-2027.

heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q105. Do credit rating agencies recognize the risks associated with significant capital expenditures?

A105. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[89]

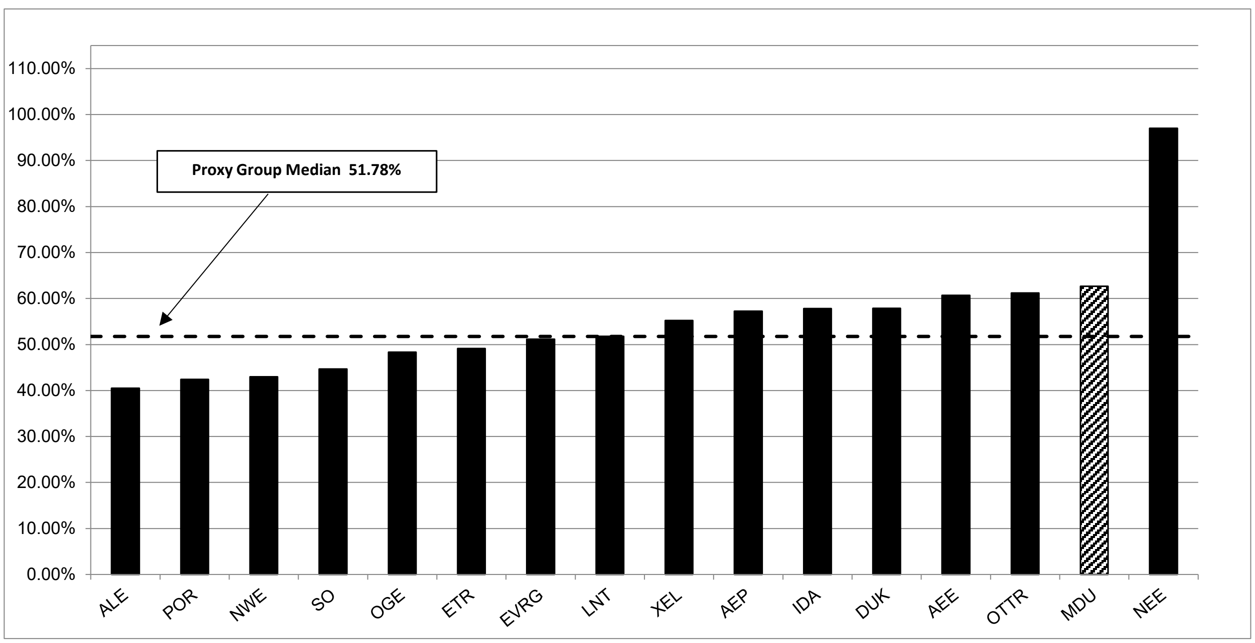
Therefore, to the extent that the Company's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

[89] S&P Global Ratings, Ratings Direct, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Q106. Have you conducted any analysis of the Company's projected capital expenditures relative to the proxy companies?

A106. As shown in Exhibit No. ___(AEB-2), Schedule 11, I calculated the ratio of expected capital expenditures to net utility plant for Montana-Dakota and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period 2023-2027 by its total net utility plant as of December 31, 2021. As shown in Exhibit No. ___(AEB-2), Schedule 11 (*see* also Figure 14 below), MDU's ratio of capital expenditures as a percentage of net utility plant of 62.66 percent is approximately 1.21 times the median for the proxy group companies of 51.78 percent. This result indicates a risk level for Montana-Dakota that is higher than the proxy group companies.

Figure 14: Comparison of Capital Expenditures – Proxy Group Companies



Q107. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A107. No. Montana-Dakota currently has not requested approval to recover capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Montana-Dakota depends entirely on rate case filings for capital cost recovery. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No.___(AEB-2), Schedule 12, 74.03 percent of the companies in the proxy group have some form of capital cost recovery mechanisms in place. Since Montana-Dakota does not currently have a capital tracking mechanism, Montana-Dakota's risk relative to the proxy group is significantly increased.

Q108. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A108. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures. Therefore, Montana-Dakota's significant capital expenditures plan and limited ability to recover the capital investment on an as incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

E. Regulatory Risk

Q109. Please explain how the regulatory framework affects investors' risk assessments.

A109. 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.

Q110. Please explain how credit rating agencies consider the regulatory framework in establishing a company's credit rating.

A110. 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. [90]

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." [91] 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.[92]

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[90] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[91] 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.

[92] *Id.*, at 1.

Q111. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A111. 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."[93] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation." [94]

Q112. Have you conducted any analysis of the regulatory framework in Montana relative to the jurisdictions in which the companies in your proxy group operate?

A112. Yes. I have evaluated the regulatory framework in Montana based on four factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These factors are: 1) fuel cost recovery; 2) test year convention (i.e., forecast vs. historical); 3) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and 4) prevalence of capital cost recovery between rate cases. The results of my regulatory risk assessment are shown in Exhibit No. ___(AEB-2), Schedule 12 and are summarized below.

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[93] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 6 (June 23, 2017).
[94] *Ibid.*

Fuel Cost Recovery: Montana-Dakota has a Fuel and Purchased Power Cost Tracking Adjustment Mechanism to recover electric fuel and purchased power costs. However, while traditional fuel cost recovery mechanisms allow all variances between projected fuel costs and actual fuel costs to be recovered from or refunded to customers, the Fuel and Purchased Power Cost Tracking Adjustment Mechanism for Montana-Dakota requires the Company to absorb some portion of the variation in power costs. Specifically, Montana-Dakota's Fuel and Purchased Power Cost Tracking Adjustment Mechanism allows the Company to only defer and recover 90 percent of the difference between actual fuel and purchased power costs and the cost of fuel and purchased power costs included in base rates plus the annual unreflected fuel cost adjustment. As a result, the Fuel and Purchased Power Cost Tracking Adjustment Mechanism does not fully mitigate the power cost risk for Montana-Dakota. This is important to investors because fuel and purchased power costs typically account for 50–60 percent of the total operating costs for a regulated utility. Moreover, according to S&P Capital IQ Pro, there are only nine states (i.e., Arizona, Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, and Wyoming) that have fuel cost recovery mechanisms with sharing bands. The remaining 41 states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs. In addition, approximately 90.91 percent of the operating companies held by the proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands, sharing bands and earnings tests.

Test year convention: Montana-Dakota uses a historical test year adjusted for known and measurable changes in Montana, while 49.35 percent of the operating companies held by the proxy group provide service in jurisdictions that use a fully or partially forecast test year. Forecast test years have been relied on for several years and produce cost estimates that are more reflective of future costs which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos explain in their 2010 report, *Forward Test Years for US Electric Utilities*:

> This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.[95]

Non-Volumetric Rate Design: Montana-Dakota does not have protection against volumetric risk in Montana, either through a revenue decoupling mechanism, formula rate plan or straight fixed-variable rate design. However, 43 out of 77 (55.84 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 not have a capital tracking mechanism to recover capital investment costs between rate cases. However,

[95] M.N. Lowry, D. Hovde, L. Getachew, and M. Makos, Forward Test Years for US Electric Utilities, prepared for Edison Electric Institute, August 2010, at 1.

74.03 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

Q113. Have you developed any additional analyses to evaluate the regulatory environment in Montana as compared to the jurisdictions in which the companies in your proxy group operate?

A113. Yes. I have conducted two additional analyses to compare the regulatory framework of Montana to the jurisdictions in which the companies in the proxy group operate. Specifically, I considered two different rankings: (1) the Regulatory Research Associates ("RRA") ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q114. Please explain how you used the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with the Company's regulatory jurisdiction.

A114. RRA develops their ranking based on their assessment of how investors perceive the regulatory risk associated with ownership of utility securities in that jurisdiction, specifically reflecting their assessment of the probable level and quality of earnings to be realized by the State's utilities as a result of regulatory, legislative, and court actions. RRA assigns a ranking for each regulatory jurisdiction between "Above Average/1" to "Below Average/3," with nine total rankings between these categories. I applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking ("1") and "Below Average/3" assigned the lowest ranking ("9"). As shown in Exhibit No. ______(AEB-2), Schedule 13, the Montana regulatory environment is ranked as "Below Average/1," while the proxy group is ranked between "Average/1" and "Average/2."

Additionally, Montana is one of nine Commissions[96] out of the 53 Commissions that RRA ranks to receive a rating of either "Below Average/1", "Below Average/2" or "Below Average/3".

Q115. How did you conduct your analysis of the S&P Credit Supportiveness?

A115. S&P classifies the regulatory jurisdictions into five categories ranging from "Credit Supportive" to "Most Credit Supportive" based on the level of credit supportiveness. Similar to the RRA regulatory ranking analysis discussed above, I assigned a numerical ranking to each jurisdiction ranked by S&P, from most credit supportive ("1") to credit supportive ("5"). As shown in Exhibit No._(AEB-2), Schedule 14, the proxy group is ranked between very credit supportive and highly credit supportive while the Montana regulatory jurisdiction is only ranked as more credit supportive. Thus, similar to the results using the RRA regulatory rankings, Montana is perceived as being below the average for the proxy group.

Q116. Has RRA provided recent commentary regarding its regulatory ranking for the Montana?

A116. Yes. In July 2022, RRA updated its evaluation of the regulatory environment in Montana and noted the following:

> The regulatory climate in Montana is somewhat restrictive from an investor point-of-view. Authorized ROEs have generally been consistent with prevailing industry averages at the time established, as calculated by Regulatory Research Associates, an offering of S&P Global Market Intelligence. In addition, the PSC relies upon historical test periods,

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[96] The other eight Commissions are the Arizona Corporation Commission, the Regulatory Commission of Alaska, the Public Utilities Regulatory Authority of Connecticut, the District of Columbia Public Service Commission, the Kansas Corporation Commission, the New Jersey Board of Public Utilities, the New Mexico Public Regulation Commission, and the Public Service Commission of West Virginia.

> which coupled with an average rate base valuation methodology, exacerbates regulatory lag. While many rate cases are resolved by settlements, the regulators have been known to modify certain aspects of the agreement, and in so doing, lowering the authorized rate increase. State law initially called for implementation of retail competition for electric generation, but subsequent legislation reversed this process. While Montana utilities are permitted to seek pre-approval of the regulatory framework to apply to new generation assets, a cash return on construction work in progress is not allowed. Also, the PSC has opposed strategic mergers, rejecting one recent major deal outright. Regulation of the gas local distribution companies, or LDCs, has been more stable, as retail choice has been in place since the late-1990s, and LDCs are now permitted to acquire upstream assets. Both the electric and gas utilities have mechanisms in place to provide expedited recognition of changes in commodity and related costs; some of these include cost-sharing provisions. However, there are no other innovative or alternative ratemaking provisions in place. RRA accords Montana a Below Average/1 ranking.[97]

Q117. What is your conclusion regarding the regulatory framework in Montana as compared with the jurisdictions in which the proxy group companies operate?

A117. 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 comprehensive fuel cost recovery mechanisms, forecasted test years, capital cost recovery trackers and non-volumetric rate design than Montana-Dakota has in Montana. In addition, the RRA jurisdictional ranking and the S&P credit supportiveness ranking for Montana indicates greater risk than the average for the proxy group. Therefore, the average ROE for the proxy group would understate the return on equity that an investor

[97] Regulatory Research Associates, Profile of Montana Public Service Commission, accessed October 19, 2022.

would require in Montana because the risks of timely and full cost recovery are greater for Montana-Dakota in Montana than for the proxy group. 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/mean.

VIII. CAPITAL STRUCTURE

Q118. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A118. 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.

Q119. What is Montana-Dakota's proposed capital structure?

A119. Montana-Dakota's proposal is to establish a capital structure consisting of 50.30 percent common equity, 46.061 percent long-term debt and 3.639 percent short-term debt.

Q120. Did you conduct any analysis to determine if this projected equity ratio was reasonable?

A120. 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.

Q121. Please discuss your analysis of the capital structures of the proxy group companies.

A121. I calculated the mean proportions of common equity, long-term debt and short-term debt for the most recent eight quarters[98] 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 15. As shown in Exhibit No. ___(AEB-2), Schedule 15, the equity ratios for the proxy group ranged from 45.43 percent to 59.86 percent, with an average of 52.29 percent. Montana-Dakota's proposed equity ratio of 50.30 percent is below the average equity ratio for the utility operating subsidiaries of the proxy group and is therefore reasonable.

Q122. Are there other factors to be considered in setting the Company's capital structure?

A122. The credit rating agencies' response to the Tax Cuts and Jobs Act of 2017 (TCJA) must also be considered when determining the equity ratio. While I recognize that the TCJA was enacted in 2017, the changes to the cash flow for utilities was altered permanently through this Act, as noted by all three rating agencies at the time that the legislation was enacted. 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

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[98] 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 third quarter of 2020 through the second quarter of 2022.

request stronger capital structures and other means to offset some of the negative impact".[99] Furthermore, Moody's downgraded the rating outlook for the entire utilities sector in June 2018 and has continued to 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[100] 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.[101] 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.[102]

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[99] Standard & Poor's Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound", January 24, 2018, at 5.

[100] S&P Global Ratings, "Regulated Utilities: Credit quality has weakened and credit risks are rising," July 14, 2022.

[101] S&P Global Ratings, "For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category," January 20, 2022.

[102] *Ibid.*

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.

Q123. Is there a relationship between the equity ratio and the authorized ROE?

A123. 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.

Q124. What is your conclusion regarding an appropriate equity ratio for Montana-Dakota?

A124. Considering the actual capital structures of the proxy group operating companies, I believe that Montana-Dakota's proposed common equity ratio of 50.30 percent is reasonable. The proposed equity ratio is 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

Q125. What is your conclusion regarding a fair ROE for Montana-Dakota?

A125.

A126. Figure 15 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 Montana.

Figure 15: Summary of Analytical Results

	Constant Growth DCF		
	Mean Low	Mean	Mean High
30-Day Average	8.05%	9.12%	10.14%
90-Day Average	8.09%	9.16%	10.18%
180-Day Average	8.12%	9.19%	10.21%
	Median Low	Median	Median High
30-Day Average	7.60%	9.22%	9.99%
90-Day Average	7.74%	9.28%	9.98%
180-Day Average	7.87%	9.35%	10.01%
	CAPM		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.89%	11.94%	11.93%
Bloomberg Beta	11.32%	11.40%	11.38%
Long-term Avg. Beta	10.59%	10.70%	10.68%
	ECAPM		
Value Line Beta	12.18%	12.22%	12.21%
Bloomberg Beta	11.75%	11.81%	11.80%
Long-term Avg. Beta	11.21%	11.29%	11.27%
	Bond Yield Risk Premium		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.14%	10.32%	10.28%

Q126. What is your conclusion regarding the Company's proposed common equity ratio?

A127. I conclude that Montana-Dakota's proposed capital structure consisting of 50.30 percent common equity, 46.061 percent long-term debt and 3.639 percent short-term debt is 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 and inflation on cash flows and therefore should be adopted.

Q127. Does this conclude you direct testimony?

A128. 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				
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
Pacificorp, d/b/a Pacific Power	5/22	Pacificorp, d/b/a Pacific Power		Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Indiana 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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
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	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	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	8.05%	9.12%	10.14%
90-Day Average	8.09%	9.16%	10.18%
180-Day Average	8.12%	9.19%	10.21%
Constant Growth Average	8.08%	9.16%	10.18%
	Median Low	Median	Median High
30-Day Average	7.60%	9.22%	9.99%
90-Day Average	7.74%	9.28%	9.98%
180-Day Average	7.87%	9.35%	10.01%
Constant Growth Average	7.74%	9.28%	10.00%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.89%	11.94%	11.93%
Bloomberg Beta	11.32%	11.40%	11.38%
Long-term Avg. Beta	10.59%	10.70%	10.68%
ECAPM			
Value Line Beta	12.18%	12.22%	12.21%
Bloomberg Beta	11.75%	11.81%	11.80%
Long-term Avg. Beta	11.21%	11.29%	11.27%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.14%	10.32%	10.28%

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Covered by More Than 1 Analyst	[4] Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	[5] Generation Assets Included in Rate Base	[6] % Company-Owned Generation > 40%	[7] % Regulated Operating Income > 60%	[8] % Regulated Electric Operating Income > 80%	[9] 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

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	$58.39	4.45%	4.62%	6.00%	8.70%	8.10%	7.60%	10.59%	12.22%	13.35%
Alliant Energy Corporation	LNT	$1.71	$60.91	2.81%	2.89%	6.00%	6.30%	6.20%	6.17%	8.89%	9.06%	9.20%
Ameren Corporation	AEE	$2.36	$91.83	2.57%	2.66%	6.50%	6.37%	7.20%	6.69%	9.02%	9.35%	9.86%
American Electric Power Company, Inc.	AEP	$3.12	$100.22	3.11%	3.21%	6.50%	6.25%	6.10%	6.28%	9.31%	9.49%	9.71%
Duke Energy Corporation	DUK	$4.02	$106.48	3.78%	3.88%	5.00%	5.62%	6.10%	5.57%	8.87%	9.45%	9.99%
Entergy Corporation	ETR	$4.04	$115.37	3.50%	3.60%	4.00%	6.19%	6.80%	5.66%	7.57%	9.26%	10.42%
Evergy, Inc.	EVRG	$2.29	$67.69	3.38%	3.48%	7.50%	3.71%	5.20%	5.47%	7.16%	8.95%	11.01%
IDACORP, Inc.	IDA	$3.00	$109.12	2.75%	2.79%	4.00%	2.70%	2.70%	3.13%	5.49%	5.93%	6.80%
NextEra Energy, Inc.	NEE	$1.70	$86.05	1.98%	2.07%	10.00%	9.35%	9.70%	9.68%	11.42%	11.75%	12.07%
NorthWestern Corporation	NWE	$2.52	$53.30	4.73%	4.80%	3.00%	4.50%	1.70%	3.07%	6.47%	7.87%	9.33%
OGE Energy Corporation	OGE	$1.64	$40.75	4.02%	4.10%	6.50%	1.90%	3.50%	3.97%	5.96%	8.07%	10.66%
Otter Tail Corporation	OTTR	$1.65	$72.44	2.28%	2.35%	4.50%	9.00%	n/a	6.75%	6.83%	9.10%	11.38%
Portland General Electric Company	POR	$1.81	$50.58	3.58%	3.65%	4.50%	3.16%	4.60%	4.09%	6.80%	7.74%	8.26%
Southern Company	SO	$2.72	$77.01	3.53%	3.63%	6.50%	6.59%	4.00%	5.70%	7.60%	9.33%	10.24%
Xcel Energy Inc.	XEL	$1.95	$73.40	2.66%	2.74%	6.00%	7.04%	6.40%	6.48%	8.74%	9.22%	9.79%
Mean				3.27%	3.37%	5.77%	5.83%	5.59%	5.75%	8.05%	9.12%	10.14%
Median				3.38%	3.48%	6.00%	6.25%	6.10%	5.70%	7.60%	9.22%	9.99%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 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	$59.22	4.39%	4.56%	6.00%	8.70%	8.10%	7.60%	10.52%	12.16%	13.28%
Alliant Energy Corporation	LNT	$1.71	$59.82	2.86%	2.95%	6.00%	6.30%	6.20%	6.17%	8.94%	9.11%	9.25%
Ameren Corporation	AEE	$2.36	$90.31	2.61%	2.70%	6.50%	6.37%	7.20%	6.69%	9.07%	9.39%	9.91%
American Electric Power Company, Inc.	AEP	$3.12	$97.87	3.19%	3.29%	6.50%	6.25%	6.10%	6.28%	9.39%	9.57%	9.79%
Duke Energy Corporation	DUK	$4.02	$106.71	3.77%	3.87%	5.00%	5.62%	6.10%	5.57%	8.86%	9.45%	9.98%
Entergy Corporation	ETR	$4.04	$113.92	3.55%	3.65%	4.00%	6.19%	6.80%	5.66%	7.62%	9.31%	10.47%
Evergy, Inc.	EVRG	$2.29	$66.59	3.44%	3.53%	7.50%	3.71%	5.20%	5.47%	7.21%	9.00%	11.07%
IDACORP, Inc.	IDA	$3.00	$107.39	2.79%	2.84%	4.00%	2.70%	2.70%	3.13%	5.53%	5.97%	6.85%
NextEra Energy, Inc.	NEE	$1.70	$81.95	2.07%	2.17%	10.00%	9.35%	9.70%	9.68%	11.52%	11.86%	12.18%
NorthWestern Corporation	NWE	$2.52	$55.43	4.55%	4.62%	3.00%	4.50%	1.70%	3.07%	6.28%	7.68%	9.15%
OGE Energy Corporation	OGE	$1.64	$39.76	4.13%	4.21%	6.50%	1.90%	3.50%	3.97%	6.06%	8.17%	10.76%
Otter Tail Corporation	OTTR	$1.65	$69.91	2.36%	2.44%	4.50%	9.00%	n/a	6.75%	6.91%	9.19%	11.47%
Portland General Electric Company	POR	$1.81	$49.74	3.64%	3.71%	4.50%	3.16%	4.60%	4.09%	6.86%	7.80%	8.32%
Southern Company	SO	$2.72	$74.22	3.66%	3.77%	6.50%	6.59%	4.00%	5.70%	7.74%	9.47%	10.38%
Xcel Energy Inc.	XEL	$1.95	$71.79	2.72%	2.80%	6.00%	7.04%	6.40%	6.48%	8.80%	9.28%	9.85%
Mean				3.31%	3.41%	5.77%	5.83%	5.59%	5.75%	8.09%	9.16%	10.18%
Median				3.44%	3.53%	6.00%	6.25%	6.10%	5.70%	7.74%	9.28%	9.98%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 30, 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

		[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	$60.46	4.30%	4.46%	6.00%	8.70%	8.10%	7.60%	10.43%	12.06%	13.19%
Alliant Energy Corporation	LNT	$1.71	$59.52	2.87%	2.96%	6.00%	6.30%	6.20%	6.17%	8.96%	9.13%	9.26%
Ameren Corporation	AEE	$2.36	$89.66	2.63%	2.72%	6.50%	6.37%	7.20%	6.69%	9.09%	9.41%	9.93%
American Electric Power Company, Inc.	AEP	$3.12	$95.79	3.26%	3.36%	6.50%	6.25%	6.10%	6.28%	9.46%	9.64%	9.86%
Duke Energy Corporation	DUK	$4.02	$105.88	3.80%	3.90%	5.00%	5.62%	6.10%	5.57%	8.89%	9.48%	10.01%
Entergy Corporation	ETR	$4.04	$112.84	3.58%	3.68%	4.00%	6.19%	6.80%	5.66%	7.65%	9.35%	10.50%
Evergy, Inc.	EVRG	$2.29	$65.69	3.49%	3.58%	7.50%	3.71%	5.20%	5.47%	7.26%	9.05%	11.12%
IDACORP, Inc.	IDA	$3.00	$107.56	2.79%	2.83%	4.00%	2.70%	2.70%	3.13%	5.53%	5.97%	6.84%
NextEra Energy, Inc.	NEE	$1.70	$79.48	2.14%	2.24%	10.00%	9.35%	9.70%	9.68%	11.59%	11.93%	12.25%
NorthWestern Corporation	NWE	$2.52	$56.53	4.46%	4.53%	3.00%	4.50%	1.70%	3.07%	6.20%	7.59%	9.06%
OGE Energy Corporation	OGE	$1.64	$39.03	4.20%	4.29%	6.50%	1.90%	3.50%	3.97%	6.14%	8.25%	10.84%
Otter Tail Corporation	OTTR	$1.65	$65.67	2.51%	2.60%	4.50%	9.00%	n/a	6.75%	7.07%	9.35%	11.63%
Portland General Electric Company	POR	$1.81	$50.23	3.60%	3.68%	4.50%	3.16%	4.60%	4.09%	6.82%	7.76%	8.29%
Southern Company	SO	$2.72	$71.63	3.80%	3.91%	6.50%	6.59%	4.00%	5.70%	7.87%	9.60%	10.51%
Xcel Energy Inc.	XEL	$1.95	$70.73	2.76%	2.85%	6.00%	7.04%	6.40%	6.48%	8.84%	9.33%	9.89%
Mean				3.35%	3.44%	5.77%	5.83%	5.59%	5.75%	8.12%	9.19%	10.21%
Median				3.49%	3.58%	6.00%	6.25%	6.10%	5.70%	7.87%	9.35%	10.01%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 30, 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

$K = Rf + \beta\,(Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

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	3.47%	0.90	13.04%	9.58%	12.08%	12.32%
Alliant Energy Corporation	LNT	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
Ameren Corporation	AEE	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
American Electric Power Company, Inc.	AEP	3.47%	0.75	13.04%	9.58%	10.65%	11.25%
Duke Energy Corporation	DUK	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
Entergy Corporation	ETR	3.47%	0.95	13.04%	9.58%	12.56%	12.68%
Evergy, Inc.	EVRG	3.47%	0.90	13.04%	9.58%	12.08%	12.32%
IDACORP, Inc.	IDA	3.47%	0.80	13.04%	9.58%	11.13%	11.61%
NextEra Energy, Inc.	NEE	3.47%	0.95	13.04%	9.58%	12.56%	12.68%
NorthWestern Corporation	NWE	3.47%	0.95	13.04%	9.58%	12.56%	12.68%
OGE Energy Corporation	OGE	3.47%	1.05	13.04%	9.58%	13.52%	13.40%
Otter Tail Corporation	OTTR	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
Portland General Electric Company	POR	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
Southern Company	SO	3.47%	0.90	13.04%	9.58%	12.08%	12.32%
Xcel Energy Inc.	XEL	3.47%	0.80	13.04%	9.58%	11.13%	11.61%
Mean						11.89%	12.18%
Median						11.61%	11.97%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 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

$K = Rf + \beta\,(Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2023 - Q1 2024)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.88%	0.90	13.04%	9.16%	12.13%	12.36%
Alliant Energy Corporation	LNT	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
Ameren Corporation	AEE	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
American Electric Power Company, Inc.	AEP	3.88%	0.75	13.04%	9.16%	10.75%	11.32%
Duke Energy Corporation	DUK	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
Entergy Corporation	ETR	3.88%	0.95	13.04%	9.16%	12.58%	12.70%
Evergy, Inc.	EVRG	3.88%	0.90	13.04%	9.16%	12.13%	12.36%
IDACORP, Inc.	IDA	3.88%	0.80	13.04%	9.16%	11.21%	11.67%
NextEra Energy, Inc.	NEE	3.88%	0.95	13.04%	9.16%	12.58%	12.70%
NorthWestern Corporation	NWE	3.88%	0.95	13.04%	9.16%	12.58%	12.70%
OGE Energy Corporation	OGE	3.88%	1.05	13.04%	9.16%	13.50%	13.39%
Otter Tail Corporation	OTTR	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
Portland General Electric Company	POR	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
Southern Company	SO	3.88%	0.90	13.04%	9.16%	12.13%	12.36%
Xcel Energy Inc.	XEL	3.88%	0.80	13.04%	9.16%	11.21%	11.67%
Mean						11.94%	12.22%
Median						11.67%	12.01%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 9, September 30, 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 (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.90	13.04%	9.24%	12.12%	12.35%
Alliant Energy Corporation	LNT	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
Ameren Corporation	AEE	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
American Electric Power Company, Inc.	AEP	3.80%	0.75	13.04%	9.24%	10.73%	11.31%
Duke Energy Corporation	DUK	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
Entergy Corporation	ETR	3.80%	0.95	13.04%	9.24%	12.58%	12.70%
Evergy, Inc.	EVRG	3.80%	0.90	13.04%	9.24%	12.12%	12.35%
IDACORP, Inc.	IDA	3.80%	0.80	13.04%	9.24%	11.19%	11.66%
NextEra Energy, Inc.	NEE	3.80%	0.95	13.04%	9.24%	12.58%	12.70%
NorthWestern Corporation	NWE	3.80%	0.95	13.04%	9.24%	12.58%	12.70%
OGE Energy Corporation	OGE	3.80%	1.05	13.04%	9.24%	13.50%	13.39%
Otter Tail Corporation	OTTR	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
Portland General Electric Company	POR	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
Southern Company	SO	3.80%	0.90	13.04%	9.24%	12.12%	12.35%
Xcel Energy Inc.	XEL	3.80%	0.80	13.04%	9.24%	11.19%	11.66%
Mean						11.93%	12.21%
Median						11.66%	12.00%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, 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	3.47%	0.83	13.04%	9.58%	11.39%	11.80%
Alliant Energy Corporation	LNT	3.47%	0.81	13.04%	9.58%	11.21%	11.67%
Ameren Corporation	AEE	3.47%	0.77	13.04%	9.58%	10.81%	11.37%
American Electric Power Company, Inc.	AEP	3.47%	0.78	13.04%	9.58%	10.96%	11.48%
Duke Energy Corporation	DUK	3.47%	0.73	13.04%	9.58%	10.50%	11.13%
Entergy Corporation	ETR	3.47%	0.88	13.04%	9.58%	11.85%	12.15%
Evergy, Inc.	EVRG	3.47%	0.81	13.04%	9.58%	11.27%	11.71%
IDACORP, Inc.	IDA	3.47%	0.82	13.04%	9.58%	11.33%	11.76%
NextEra Energy, Inc.	NEE	3.47%	0.83	13.04%	9.58%	11.38%	11.79%
NorthWestern Corporation	NWE	3.47%	0.88	13.04%	9.58%	11.88%	12.17%
OGE Energy Corporation	OGE	3.47%	0.94	13.04%	9.58%	12.46%	12.60%
Otter Tail Corporation	OTTR	3.47%	0.88	13.04%	9.58%	11.87%	12.17%
Portland General Electric Company	POR	3.47%	0.80	13.04%	9.58%	11.13%	11.61%
Southern Company	SO	3.47%	0.80	13.04%	9.58%	11.10%	11.59%
Xcel Energy Inc.	XEL	3.47%	0.76	13.04%	9.58%	10.71%	11.29%
Mean						11.32%	11.75%
Median						11.27%	11.71%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2022
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of August 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

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2023 - Q1 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.88%	0.83	13.04%	9.16%	11.46%	11.85%
Alliant Energy Corporation	LNT	3.88%	0.81	13.04%	9.16%	11.29%	11.73%
Ameren Corporation	AEE	3.88%	0.77	13.04%	9.16%	10.91%	11.44%
American Electric Power Company, Inc.	AEP	3.88%	0.78	13.04%	9.16%	11.05%	11.55%
Duke Energy Corporation	DUK	3.88%	0.73	13.04%	9.16%	10.61%	11.22%
Entergy Corporation	ETR	3.88%	0.88	13.04%	9.16%	11.90%	12.19%
Evergy, Inc.	EVRG	3.88%	0.81	13.04%	9.16%	11.35%	11.77%
IDACORP, Inc.	IDA	3.88%	0.82	13.04%	9.16%	11.41%	11.82%
NextEra Energy, Inc.	NEE	3.88%	0.83	13.04%	9.16%	11.45%	11.85%
NorthWestern Corporation	NWE	3.88%	0.88	13.04%	9.16%	11.93%	12.21%
OGE Energy Corporation	OGE	3.88%	0.94	13.04%	9.16%	12.48%	12.62%
Otter Tail Corporation	OTTR	3.88%	0.88	13.04%	9.16%	11.92%	12.20%
Portland General Electric Company	POR	3.88%	0.80	13.04%	9.16%	11.21%	11.67%
Southern Company	SO	3.88%	0.80	13.04%	9.16%	11.19%	11.65%
Xcel Energy Inc.	XEL	3.88%	0.76	13.04%	9.16%	10.81%	11.37%
Mean						11.40%	11.81%
Median						11.35%	11.77%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 9, September 30, 2022, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of August 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

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.83	13.04%	9.24%	11.44%	11.84%
Alliant Energy Corporation	LNT	3.80%	0.81	13.04%	9.24%	11.27%	11.72%
Ameren Corporation	AEE	3.80%	0.77	13.04%	9.24%	10.89%	11.43%
American Electric Power Company, Inc.	AEP	3.80%	0.78	13.04%	9.24%	11.04%	11.54%
Duke Energy Corporation	DUK	3.80%	0.73	13.04%	9.24%	10.59%	11.20%
Entergy Corporation	ETR	3.80%	0.88	13.04%	9.24%	11.89%	12.18%
Evergy, Inc.	EVRG	3.80%	0.81	13.04%	9.24%	11.33%	11.76%
IDACORP, Inc.	IDA	3.80%	0.82	13.04%	9.24%	11.39%	11.81%
NextEra Energy, Inc.	NEE	3.80%	0.83	13.04%	9.24%	11.44%	11.84%
NorthWestern Corporation	NWE	3.80%	0.88	13.04%	9.24%	11.92%	12.20%
OGE Energy Corporation	OGE	3.80%	0.94	13.04%	9.24%	12.48%	12.62%
Otter Tail Corporation	OTTR	3.80%	0.88	13.04%	9.24%	11.91%	12.20%
Portland General Electric Company	POR	3.80%	0.80	13.04%	9.24%	11.20%	11.66%
Southern Company	SO	3.80%	0.80	13.04%	9.24%	11.17%	11.64%
Xcel Energy Inc.	XEL	3.80%	0.76	13.04%	9.24%	10.79%	11.35%
Mean						11.38%	11.80%
Median						11.33%	11.76%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns, as of August 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

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	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	3.47%	0.77	13.04%	9.58%	10.86%	11.41%
Alliant Energy Corporation	LNT	3.47%	0.74	13.04%	9.58%	10.54%	11.17%
Ameren Corporation	AEE	3.47%	0.71	13.04%	9.58%	10.28%	10.97%
American Electric Power Company, Inc.	AEP	3.47%	0.67	13.04%	9.58%	9.85%	10.65%
Duke Energy Corporation	DUK	3.47%	0.64	13.04%	9.58%	9.64%	10.49%
Entergy Corporation	ETR	3.47%	0.72	13.04%	9.58%	10.38%	11.05%
Evergy, Inc.	EVRG	3.47%	0.98	13.04%	9.58%	12.80%	12.86%
IDACORP, Inc.	IDA	3.47%	0.72	13.04%	9.58%	10.38%	11.05%
NextEra Energy, Inc.	NEE	3.47%	0.71	13.04%	9.58%	10.22%	10.93%
NorthWestern Corporation	NWE	3.47%	0.73	13.04%	9.58%	10.44%	11.09%
OGE Energy Corporation	OGE	3.47%	0.92	13.04%	9.58%	12.30%	12.48%
Otter Tail Corporation	OTTR	3.47%	0.85	13.04%	9.58%	11.61%	11.97%
Portland General Electric Company	POR	3.47%	0.74	13.04%	9.58%	10.54%	11.17%
Southern Company	SO	3.47%	0.63	13.04%	9.58%	9.48%	10.37%
Xcel Energy Inc.	XEL	3.47%	0.64	13.04%	9.58%	9.58%	10.45%
Mean						10.59%	11.21%
Median						10.38%	11.05%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 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

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2023 - Q1 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.88%	0.77	13.04%	9.16%	10.96%	11.48%
Alliant Energy Corporation	LNT	3.88%	0.74	13.04%	9.16%	10.65%	11.25%
Ameren Corporation	AEE	3.88%	0.71	13.04%	9.16%	10.40%	11.06%
American Electric Power Company, Inc.	AEP	3.88%	0.67	13.04%	9.16%	9.99%	10.75%
Duke Energy Corporation	DUK	3.88%	0.64	13.04%	9.16%	9.78%	10.60%
Entergy Corporation	ETR	3.88%	0.72	13.04%	9.16%	10.50%	11.13%
Evergy, Inc.	EVRG	3.88%	0.98	13.04%	9.16%	12.81%	12.87%
IDACORP, Inc.	IDA	3.88%	0.72	13.04%	9.16%	10.50%	11.13%
NextEra Energy, Inc.	NEE	3.88%	0.71	13.04%	9.16%	10.34%	11.02%
NorthWestern Corporation	NWE	3.88%	0.73	13.04%	9.16%	10.55%	11.17%
OGE Energy Corporation	OGE	3.88%	0.92	13.04%	9.16%	12.33%	12.51%
Otter Tail Corporation	OTTR	3.88%	0.85	13.04%	9.16%	11.67%	12.01%
Portland General Electric Company	POR	3.88%	0.74	13.04%	9.16%	10.65%	11.25%
Southern Company	SO	3.88%	0.63	13.04%	9.16%	9.63%	10.48%
Xcel Energy Inc.	XEL	3.88%	0.64	13.04%	9.16%	9.73%	10.56%
Mean						10.70%	11.29%
Median						10.50%	11.13%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 9, September 30, 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

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.77	13.04%	9.24%	10.94%	11.46%
Alliant Energy Corporation	LNT	3.80%	0.74	13.04%	9.24%	10.63%	11.23%
Ameren Corporation	AEE	3.80%	0.71	13.04%	9.24%	10.37%	11.04%
American Electric Power Company, Inc.	AEP	3.80%	0.67	13.04%	9.24%	9.96%	10.73%
Duke Energy Corporation	DUK	3.80%	0.64	13.04%	9.24%	9.76%	10.58%
Entergy Corporation	ETR	3.80%	0.72	13.04%	9.24%	10.48%	11.12%
Evergy, Inc.	EVRG	3.80%	0.98	13.04%	9.24%	12.81%	12.87%
IDACORP, Inc.	IDA	3.80%	0.72	13.04%	9.24%	10.48%	11.12%
NextEra Energy, Inc.	NEE	3.80%	0.71	13.04%	9.24%	10.32%	11.00%
NorthWestern Corporation	NWE	3.80%	0.73	13.04%	9.24%	10.53%	11.16%
OGE Energy Corporation	OGE	3.80%	0.92	13.04%	9.24%	12.32%	12.50%
Otter Tail Corporation	OTTR	3.80%	0.85	13.04%	9.24%	11.66%	12.00%
Portland General Electric Company	POR	3.80%	0.74	13.04%	9.24%	10.63%	11.23%
Southern Company	SO	3.80%	0.63	13.04%	9.24%	9.60%	10.46%
Xcel Energy Inc.	XEL	3.80%	0.64	13.04%	9.24%	9.71%	10.54%
Mean						10.68%	11.27%
Median						10.48%	11.12%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, 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	0.60	0.60	0.90	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	0.60	0.58	0.88	0.89	0.73

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Average ([1] - [9])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.98%
[2] Estimated Weighted Average Long-Term Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	13.04%

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.
LyondellBasell Industries NV	LYB	326.21	75.28	24,556.79	0.10%	6.32%	0.01%	3.50%	0.00%
Signature Bank/New York NY	SBNY	62.93	151.00	9,502.28		1.48%		21.50%	
American Express Co	AXP	749.75	134.91	101,148.50	0.40%	1.54%	0.01%	10.00%	0.04%
Verizon Communications Inc	VZ	4,199.72	37.97	159,463.18	0.64%	6.87%	0.04%	2.50%	0.02%
Broadcom Inc	AVGO	405.00	444.01	179,824.49		3.69%		29.50%	
Boeing Co/The	BA	593.81	121.08	71,898.64					
Caterpillar Inc	CAT	527.91	164.08	86,619.31	0.35%	2.93%	0.01%	8.00%	0.03%
JPMorgan Chase & Co	JPM	2,932.57	104.50	306,453.77	1.22%	3.83%	0.05%	5.00%	0.06%
Chevron Corp	CVX	1,957.44	143.67	281,224.69		3.95%		44.00%	
Coca-Cola Co/The	KO	4,324.63	56.02	242,265.72	0.97%	3.14%	0.03%	7.50%	0.07%
AbbVie Inc	ABBV	1,768.10	134.21	237,296.16	0.95%	4.20%	0.04%	4.50%	0.04%
Walt Disney Co/The	DIS	1,823.06	94.33	171,969.06				30.50%	
FleetCor Technologies Inc	FLT	75.01	176.17	13,215.04	0.05%			10.50%	0.01%
Extra Space Storage Inc	EXR	133.91	172.71	23,127.94	0.09%	3.47%	0.00%	4.00%	0.00%
Exxon Mobil Corp	XOM	4,167.64	87.31	363,876.30		4.03%			
Phillips 66	PSX	481.05	80.72	38,830.44		4.81%		85.00%	
General Electric Co	GE	1,096.55	61.91	67,887.60		0.52%		22.00%	
HP Inc	HPQ	1,005.94	24.92	25,068.00	0.10%	4.01%	0.00%	12.50%	0.01%
Home Depot Inc/The	HD	1,023.73	275.94	282,486.95	1.13%	2.75%	0.03%	9.00%	0.10%
Monolithic Power Systems Inc	MPWR	46.79	363.40	17,003.12		0.83%		23.50%	
International Business Machines Corp	IBM	903.18	118.81	107,306.82	0.43%	5.56%	0.02%	3.00%	0.01%
Johnson & Johnson	JNJ	2,629.18	163.36	429,502.84	1.71%	2.77%	0.05%	8.00%	0.14%
McDonald's Corp	MCD	735.72	230.74	169,759.34	0.68%	2.39%	0.02%	10.50%	0.07%
Merck & Co Inc	MRK	2,533.28	86.12	218,166.07	0.87%	3.20%	0.03%	8.00%	0.07%
3M Co	MMM	553.61	110.50	61,174.35	0.24%	5.39%	0.01%	6.50%	0.02%
American Water Works Co Inc	AWK	181.79	130.16	23,661.27	0.09%	2.01%	0.00%	3.00%	0.00%
Bank of America Corp	BAC	8,035.24	30.20	242,664.22	0.97%	2.91%	0.03%	8.50%	0.08%
Pfizer Inc	PFE	5,612.35	43.76	245,596.52	0.98%	3.66%	0.04%	6.50%	0.06%
Procter & Gamble Co/The	PG	2,389.55	126.25	301,681.19	1.20%	2.89%	0.03%	6.50%	0.08%
AT&T Inc	T	7,126.00	15.34	109,312.84	0.44%	7.24%	0.03%	0.50%	0.00%
Travelers Cos Inc/The	TRV	237.31	153.20	36,356.35	0.15%	2.43%	0.00%	6.50%	0.01%
Raytheon Technologies Corp	RTX	1,476.51	81.86	120,867.44	0.48%	2.69%	0.01%	7.00%	0.03%
Analog Devices Inc	ADI	514.34	139.34	71,668.41	0.29%	2.18%	0.01%	14.00%	0.04%
Walmart Inc	WMT	2,714.24	129.70	352,036.67	1.40%	1.73%	0.02%	7.50%	0.11%
Cisco Systems Inc	CSCO	4,108.84	40.00	164,353.76	0.66%	3.80%	0.02%	8.00%	0.05%
Intel Corp	INTC	4,106.00	25.77	105,811.62	0.42%	5.67%	0.02%	2.50%	0.01%
General Motors Co	GM	1,458.05	32.09	46,788.79	0.19%	1.12%	0.00%	10.00%	0.02%
Microsoft Corp	MSFT	7,457.89	232.90	1,736,943.05	6.93%	1.17%	0.08%	16.50%	1.14%
Dollar General Corp	DG	225.57	239.31	53,981.64	0.22%	0.92%	0.00%	10.00%	0.02%
Cigna Corp	CI	305.12	277.47	84,660.54	0.34%	1.61%	0.01%	10.00%	0.03%
Kinder Morgan Inc	KMI	2,253.00	16.64	37,489.94	0.15%	6.67%	0.01%	19.00%	0.03%
Citigroup Inc	C	1,936.71	41.67	80,702.71	0.32%	4.90%	0.02%	5.50%	0.02%
American International Group Inc	AIG	760.42	47.48	36,104.55		2.70%		#N/A	
Altria Group Inc	MO	1,800.82	40.38	72,717.23	0.29%	9.31%	0.03%	5.50%	0.02%
HCA Healthcare Inc	HCA	287.03	183.79	52,752.32	0.21%	1.22%	0.00%	12.50%	0.03%
International Paper Co	IP	362.02	31.70	11,475.94	0.05%	5.84%	0.00%	12.50%	0.01%
Hewlett Packard Enterprise Co	HPE	1,286.70	11.98	15,414.68	0.06%	4.01%	0.00%	7.50%	0.00%
Abbott Laboratories	ABT	1,751.22	96.76	169,448.05	0.68%	1.94%	0.01%	8.00%	0.05%
Aflac Inc	AFL	631.92	56.20	35,513.68	0.14%	2.85%	0.00%	9.00%	0.01%
Air Products and Chemicals Inc	APD	221.80	232.73	51,619.28	0.21%	2.78%	0.01%	12.00%	0.02%
Royal Caribbean Cruises Ltd	RCL	255.06	37.90	9,666.74					
Hess Corp	HES	309.62	108.99	33,744.94		1.38%			
Archer-Daniels-Midland Co	ADM	560.56	80.45	45,097.21	0.18%	1.99%	0.00%	13.00%	0.02%
Automatic Data Processing Inc	ADP	415.29	226.19	93,934.90	0.37%	1.84%	0.01%	10.00%	0.04%
Verisk Analytics Inc	VRSK	156.96	170.53	26,766.39	0.11%	0.73%	0.00%	10.50%	0.01%
AutoZone Inc	AZO	19.49	2,141.93	41,741.93	0.17%			14.00%	0.02%
Avery Dennison Corp	AVY	81.26	162.70	13,220.35	0.05%	1.84%	0.00%	12.00%	0.01%
Enphase Energy Inc	ENPH	135.46	277.47	37,585.25				26.50%	
MSCI Inc	MSCI	80.50	421.79	33,955.36	0.14%	1.19%	0.00%	15.50%	0.02%
Ball Corp	BALL	314.31	48.32	15,187.31		1.66%		21.50%	
Ceridian HCM Holding Inc	CDAY	153.06	55.88	8,552.83					
Carrier Global Corp	CARR	841.58	35.56	29,926.69		1.69%			
Bank of New York Mellon Corp/The	BK	808.10	38.52	31,128.13	0.12%	3.84%	0.00%	6.00%	0.01%
Otis Worldwide Corp	OTIS	420.23	63.80	26,810.80		1.82%			
Baxter International Inc	BAX	503.61	53.86	27,124.49	0.11%	2.15%	0.00%	10.00%	0.01%
Becton Dickinson and Co	BDX	285.20	222.83	63,550.00	0.25%	1.56%	0.00%	4.50%	0.01%
Berkshire Hathaway Inc	BRK/B	1,301.13	267.02	347,426.66	1.39%			6.00%	0.08%
Best Buy Co Inc	BBY	225.13	63.34	14,259.80	0.06%	5.56%	0.00%	9.50%	0.01%
Boston Scientific Corp	BSX	1,431.61	38.73	55,446.41	0.22%			16.00%	0.04%
Bristol-Myers Squibb Co	BMY	2,135.26	71.09	151,795.28		3.04%			
Fortune Brands Home & Security Inc	FBHS	129.32	53.69	6,943.03	0.03%	2.09%	0.00%	10.00%	0.00%
Brown-Forman Corp	BF/B	309.92	66.57	20,631.64	0.08%	1.13%	0.00%	14.00%	0.01%
Coterra Energy Inc	CTRA	795.60	26.12	20,780.94		9.95%			
Campbell Soup Co	CPB	299.36	47.12	14,106.03	0.06%	3.14%	0.00%	5.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	274.29	120.62	33,084.50		0.50%			
Carnival Corp	CCL	1,096.76	7.03	7,710.19					
Qorvo Inc	QRVO	103.20	79.41	8,195.43	0.03%			14.50%	0.00%
Lumen Technologies Inc	LUMN	1,035.34	7.28	7,537.27	0.03%	13.74%	0.00%	3.50%	0.00%
UDR Inc	UDR	324.92	41.71	13,552.54	0.05%	3.64%	0.00%	10.50%	0.01%
Clorox Co/The	CLX	123.16	128.39	15,812.90	0.06%	3.68%	0.00%	7.50%	0.00%
Paycom Software Inc	PAYC	60.03	329.99	19,807.98				21.00%	

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.
CMS Energy Corp	CMS	290.20	58.24	16,901.02	0.07%	3.16%	0.00%	6.50%	0.00%
Newell Brands Inc	NWL	413.60	13.89	5,744.90		6.62%			
Colgate-Palmolive Co	CL	834.12	70.25	58,596.93	0.23%	2.68%	0.01%	6.50%	0.02%
EPAM Systems Inc	EPAM	57.37	362.19	20,777.75				20.50%	
Comerica Inc	CMA	130.82	71.10	9,301.30	0.04%	3.83%	0.00%	9.00%	0.00%
Conagra Brands Inc	CAG	480.63	32.63	15,682.89	0.06%	4.05%	0.00%	4.00%	0.00%
Consolidated Edison Inc	ED	354.58	85.76	30,408.95	0.12%	3.68%	0.00%	4.00%	0.00%
Corning Inc	GLW	845.32	29.02	24,531.13	0.10%	3.72%	0.00%	17.50%	0.02%
Cummins Inc	CMI	140.99	203.51	28,693.28	0.11%	3.09%	0.00%	8.50%	0.01%
Caesars Entertainment Inc	CZR	214.42	32.26	6,917.09					
Danaher Corp	DHR	727.45	258.29	187,891.77	0.75%	0.39%	0.00%	17.00%	0.13%
Target Corp	TGT	460.26	148.39	68,298.43	0.27%	2.91%	0.01%	13.00%	0.04%
Deere & Co	DE	301.82	333.89	100,774.68	0.40%	1.35%	0.01%	15.00%	0.06%
Dominion Energy Inc	D	832.50	69.11	57,534.28	0.23%	3.86%	0.01%	5.00%	0.01%
Dover Corp	DOV	143.55	116.58	16,734.94	0.07%	1.73%	0.00%	9.00%	0.01%
Alliant Energy Corp	LNT	250.93	52.99	13,296.57	0.05%	3.23%	0.00%	6.00%	0.00%
Duke Energy Corp	DUK	770.00	93.02	71,625.40	0.29%	4.32%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	171.12	53.85	9,214.60	0.04%	4.64%	0.00%	12.50%	0.00%
Eaton Corp PLC	ETN	398.30	133.36	53,117.29	0.21%	2.43%	0.01%	12.00%	0.03%
Ecolab Inc	ECL	284.99	144.42	41,158.11	0.16%	1.41%	0.00%	10.50%	0.02%
PerkinElmer Inc	PKI	126.22	120.33	15,188.53	0.06%	0.23%	0.00%	4.00%	0.00%
Emerson Electric Co	EMR	591.30	73.22	43,294.99	0.17%	2.81%	0.00%	10.50%	0.02%
EOG Resources Inc	EOG	586.05	111.73	65,478.81	0.26%	2.69%	0.01%	18.00%	0.05%
Aon PLC	AON	210.93	267.87	56,500.75	0.23%	0.84%	0.00%	6.50%	0.01%
Entergy Corp	ETR	203.42	100.63	20,469.95	0.08%	4.01%	0.00%	4.00%	0.00%
Equifax Inc	EFX	122.40	171.43	20,983.03	0.08%	0.91%	0.00%	10.00%	0.01%
EQT Corp	EQT	369.44	40.75	15,054.68		1.47%			
IQVIA Holdings Inc	IQV	186.51	181.14	33,784.06	0.13%			14.50%	0.02%
Gartner Inc	IT	79.09	276.69	21,884.52	0.09%			15.50%	0.01%
FedEx Corp	FDX	260.22	148.47	38,634.86	0.15%	3.10%	0.00%	13.00%	0.02%
FMC Corp	FMC	125.96	105.70	13,313.87	0.05%	2.01%	0.00%	11.00%	0.01%
Brown & Brown Inc	BRO	282.45	60.48	17,082.82	0.07%	0.68%	0.00%	8.00%	0.01%
Ford Motor Co	F	3,949.39	11.20	44,233.11		5.36%		33.50%	
NextEra Energy Inc	NEE	1,964.78	78.41	154,058.32	0.61%	2.17%	0.01%	10.00%	0.06%
Franklin Resources Inc	BEN	498.36	21.52	10,724.64	0.04%	5.39%	0.00%	9.00%	0.00%
Garmin Ltd	GRMN	192.86	80.31	15,488.19	0.06%	3.64%	0.00%	6.00%	0.00%
Freeport-McMoRan Inc	FCX	1,429.27	27.33	39,061.95		2.20%		27.00%	
Dexcom Inc	DXCM	392.58	80.54	31,618.55					
General Dynamics Corp	GD	274.25	212.17	58,186.77	0.23%	2.38%	0.01%	8.50%	0.02%
General Mills Inc	GIS	593.54	76.61	45,470.79	0.18%	2.82%	0.01%	3.50%	0.01%
Genuine Parts Co	GPC	141.43	149.32	21,118.48	0.08%	2.40%	0.00%	9.00%	0.01%
Atmos Energy Corp	ATO	139.89	101.85	14,248.00	0.06%	2.67%	0.00%	7.50%	0.00%
WW Grainger Inc	GWW	50.87	489.19	24,885.58	0.10%	1.41%	0.00%	9.50%	0.01%
Halliburton Co	HAL	906.94	24.62	22,328.96		1.95%		31.00%	
L3Harris Technologies Inc	LHX	191.35	207.83	39,768.89	0.16%	2.16%	0.00%	18.00%	0.03%
Healthpeak Properties Inc	PEAK	539.58	22.92	12,367.20	0.05%	5.24%	0.00%	17.00%	0.01%
Catalent Inc	CTLT	179.90	72.36	13,017.27				21.00%	
Fortive Corp	FTV	355.70	58.30	20,737.14	0.08%	0.48%	0.00%	12.00%	0.01%
Hershey Co/The	HSY	146.87	220.47	32,380.43	0.13%	1.88%	0.00%	6.50%	0.01%
Synchrony Financial	SYF	481.76	28.19	13,580.79	0.05%	3.26%	0.00%	9.50%	0.01%
Hormel Foods Corp	HRL	546.20	45.44	24,819.24	0.10%	2.29%	0.00%	6.00%	0.01%
Arthur J Gallagher & Co	AJG	210.34	171.22	36,013.73	0.14%	1.19%	0.00%	17.50%	0.03%
Mondelez International Inc	MDLZ	1,370.57	54.83	75,148.13	0.30%	2.81%	0.01%	9.50%	0.03%
CenterPoint Energy Inc	CNP	629.43	28.18	17,737.39	0.07%	2.56%	0.00%	6.50%	0.00%
Humana Inc	HUM	126.55	485.19	61,402.74	0.25%	0.65%	0.00%	11.00%	0.03%
Willis Towers Watson PLC	WTW	109.97	200.94	22,096.57	0.09%	1.63%	0.00%	8.50%	0.01%
Illinois Tool Works Inc	ITW	309.62	180.65	55,933.21	0.22%	2.90%	0.01%	11.00%	0.02%
CDW Corp/DE	CDW	135.24	156.08	21,108.73	0.08%	1.28%	0.00%	8.50%	0.01%
Trane Technologies PLC	TT	231.72	144.81	33,554.94		1.85%			
Interpublic Group of Cos Inc/The	IPG	391.03	25.60	10,010.32	0.04%	4.53%	0.00%	10.00%	0.00%
International Flavors & Fragrances Inc	IFF	254.95	90.83	23,156.84	0.09%	3.57%	0.00%	7.50%	0.01%
Generac Holdings Inc	GNRC	63.83	178.14	11,370.85				23.50%	
NXP Semiconductors NV	NXPI	262.60	147.51	38,735.83	0.15%	2.29%	0.00%	12.00%	0.02%
Kellogg Co	K	340.11	69.66	23,692.27	0.09%	3.39%	0.00%	3.50%	0.00%
Broadridge Financial Solutions Inc	BR	154.46	144.32	22,291.81	0.09%	2.01%	0.00%	9.00%	0.01%
Kimberly-Clark Corp	KMB	337.62	112.54	37,995.98	0.15%	4.12%	0.01%	5.50%	0.01%
Kimco Realty Corp	KIM	618.48	18.41	11,386.25	0.05%	4.78%	0.00%	8.50%	0.00%
Oracle Corp	ORCL	2,696.17	61.07	164,654.86	0.66%	2.10%	0.01%	9.00%	0.06%
Kroger Co/The	KR	715.81	43.75	31,316.51	0.12%	2.38%	0.00%	5.50%	0.01%
Lennar Corp	LEN	254.99	74.55	19,009.28	0.08%	2.01%	0.00%	9.00%	0.01%
Eli Lilly & Co	LLY	950.18	323.35	307,239.09	1.23%	1.21%	0.01%	11.50%	0.14%
Bath & Body Works Inc	BBWI	228.37	32.60	7,444.99		2.45%		26.50%	
Charter Communications Inc	CHTR	160.66	303.35	48,734.69				22.50%	
Lincoln National Corp	LNC	170.23	43.91	7,474.62	0.03%	4.10%	0.00%	11.50%	0.00%
Loews Corp	L	240.95	49.84	12,008.80	0.05%	0.50%	0.00%	18.50%	0.01%
Lowe's Cos Inc	LOW	620.70	187.81	116,573.85	0.47%	2.24%	0.01%	12.50%	0.06%
IDEX Corp	IEX	75.48	199.85	15,083.88	0.06%	1.20%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	499.02	149.29	74,498.40	0.30%	1.58%	0.00%	12.00%	0.04%
Masco Corp	MAS	225.52	46.69	10,529.53	0.04%	2.40%	0.00%	8.50%	0.00%
S&P Global Inc	SPGI	333.50	305.35	101,834.23	0.41%	1.11%	0.00%	9.50%	0.04%
Medtronic PLC	MDT	1,329.15	80.75	107,329.10	0.43%	3.37%	0.01%	9.00%	0.04%
Viatris Inc	VTRS	1,212.58	8.52	10,331.19		5.63%			
CVS Health Corp	CVS	1,312.83	95.37	125,204.50	0.50%	2.31%	0.01%	6.00%	0.03%
DuPont de Nemours Inc	DD	500.90	50.40	25,245.46	0.10%	2.62%	0.00%	10.00%	0.01%
Micron Technology Inc	MU	1,103.15	50.10	55,267.56	0.22%	0.92%	0.00%	16.00%	0.04%
Motorola Solutions Inc	MSI	166.89	223.97	37,377.23	0.15%	1.41%	0.00%	8.00%	0.01%
Cboe Global Markets Inc	CBOE	106.06	117.37	12,448.50	0.05%	1.70%	0.00%	10.00%	0.00%
Laboratory Corp of America Holdings	LH	90.40	204.81	18,514.82	0.07%	1.41%	0.00%	1.50%	0.00%
Newmont Corp	NEM	793.68	42.03	33,358.37	0.13%	5.23%	0.01%	9.50%	0.01%
NIKE Inc	NKE	1,263.65	83.12	105,034.84		1.47%		24.00%	
NiSource Inc	NI	405.95	25.19	10,225.96	0.04%	3.73%	0.00%	9.50%	0.00%
Norfolk Southern Corp	NSC	234.87	209.65	49,241.33	0.20%	2.37%	0.00%	10.00%	0.02%

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.
Principal Financial Group Inc	PFG	249.24	72.15	17,982.45	0.07%	3.55%	0.00%	6.00%	0.00%
Eversource Energy	ES	346.44	77.96	27,008.70	0.11%	3.27%	0.00%	6.50%	0.01%
Northrop Grumman Corp	NOC	154.71	470.32	72,763.68	0.29%	1.47%	0.00%	6.50%	0.02%
Wells Fargo & Co	WFC	3,793.05	40.22	152,556.47	0.61%	2.98%	0.02%	11.50%	0.07%
Nucor Corp	NUE	261.79	106.99	28,008.38		1.87%		-0.50%	
Occidental Petroleum Corp	OXY	931.49	61.45	57,240.18		0.85%			
Omnicom Group Inc	OMC	204.84	63.09	12,923.54	0.05%	4.44%	0.00%	6.50%	0.00%
ONEOK Inc	OKE	446.86	51.24	22,897.21	0.09%	7.30%	0.01%	11.50%	0.01%
Raymond James Financial Inc	RJF	215.83	98.82	21,327.83	0.09%	1.38%	0.00%	10.50%	0.01%
PG&E Corp	PCG	1,987.67	12.50	24,845.85	0.10%			7.50%	0.01%
Parker-Hannifin Corp	PH	128.46	242.31	31,127.38	0.12%	2.20%	0.00%	14.00%	0.02%
Rollins Inc	ROL	492.42	34.68	17,077.02	0.07%	1.15%	0.00%	10.50%	0.01%
PPL Corp	PPL	736.19	25.35	18,662.29	0.07%	3.55%	0.00%	3.00%	0.00%
ConocoPhillips	COP	1,273.03	102.34	130,282.20	0.52%	1.80%	0.01%	20.00%	0.10%
PulteGroup Inc	PHM	231.50	37.50	8,681.18	0.03%	1.60%	0.00%	11.00%	0.00%
Pinnacle West Capital Corp	PNW	113.04	64.51	7,292.47	0.03%	5.27%	0.00%	0.50%	0.00%
PNC Financial Services Group Inc/The	PNC	410.12	149.42	61,280.73	0.24%	4.02%	0.01%	12.00%	0.03%
PPG Industries Inc	PPG	235.00	110.69	26,011.82	0.10%	2.24%	0.00%	4.00%	0.00%
Progressive Corp/The	PGR	585.10	116.21	67,994.47	0.27%	0.34%	0.00%	6.50%	0.02%
Public Service Enterprise Group Inc	PEG	498.86	56.23	28,050.90	0.11%	3.84%	0.00%	4.00%	0.00%
Robert Half International Inc	RHI	109.57	76.50	8,381.95	0.03%	2.25%	0.00%	7.50%	0.00%
Edison International	EIX	381.43	56.58	21,581.42		4.95%			
Schlumberger NV	SLB	1,414.39	35.90	50,776.53		1.95%		23.00%	
Charles Schwab Corp/The	SCHW	1,817.79	71.87	130,644.85	0.52%	1.22%	0.01%	9.00%	0.05%
Sherwin-Williams Co/The	SHW	259.18	204.75	53,067.72	0.21%	1.17%	0.00%	11.50%	0.02%
West Pharmaceutical Services Inc	WST	74.05	246.08	18,221.73	0.07%	0.29%	0.00%	17.00%	0.01%
J M Smucker Co/The	SJM	106.56	137.41	14,642.00	0.06%	2.97%	0.00%	4.00%	0.00%
Snap-on Inc	SNA	53.27	201.35	10,725.51	0.04%	2.82%	0.00%	4.50%	0.00%
AMETEK Inc	AME	229.58	113.41	26,036.44	0.10%	0.78%	0.00%	10.00%	0.01%
Southern Co/The	SO	1,062.53	68.00	72,251.70	0.29%	4.00%	0.01%	6.50%	0.02%
Truist Financial Corp	TFC	1,326.39	43.54	57,751.15	0.23%	4.78%	0.01%	6.50%	0.01%
Southwest Airlines Co	LUV	593.35	30.84	18,298.91					
W R Berkley Corp	WRB	265.27	64.58	17,131.33	0.07%	0.62%	0.00%	15.50%	0.01%
Stanley Black & Decker Inc	SWK	147.82	75.21	11,117.24	0.04%	4.25%	0.00%	6.00%	0.00%
Public Storage	PSA	175.54	292.81	51,400.45	0.21%	2.73%	0.01%	8.00%	0.02%
Arista Networks Inc	ANET	304.28	112.89	34,350.17	0.14%			10.00%	0.01%
Sysco Corp	SYY	506.11	70.71	35,787.04	0.14%	2.77%	0.00%	16.50%	0.02%
Corteva Inc	CTVA	725.32	57.15	41,452.04	0.17%	1.05%	0.00%	16.50%	0.03%
Texas Instruments Inc	TXN	913.71	154.78	141,423.57	0.56%	3.20%	0.02%	9.00%	0.05%
Textron Inc	TXT	211.53	58.26	12,323.85	0.05%	0.14%	0.00%	10.50%	0.01%
Thermo Fisher Scientific Inc	TMO	391.79	507.19	198,711.46	0.79%	0.24%	0.00%	10.00%	0.08%
TJX Cos Inc/The	TJX	1,161.05	62.12	72,124.61	0.29%	1.90%	0.01%	20.00%	0.06%
Globe Life Inc	GL	97.44	99.70	9,714.57	0.04%	0.83%	0.00%	8.00%	0.00%
Johnson Controls International plc	JCI	688.81	49.22	33,903.23	0.14%	2.84%	0.00%	13.00%	0.02%
Ulta Beauty Inc	ULTA	51.22	401.19	20,549.35	0.08%			15.00%	0.01%
Union Pacific Corp	UNP	624.48	194.82	121,661.00	0.49%	2.67%	0.01%	9.50%	0.05%
Keysight Technologies Inc	KEYS	178.80	157.36	28,135.34	0.11%			13.00%	0.01%
UnitedHealth Group Inc	UNH	935.38	505.04	472,405.83	1.89%	1.31%	0.02%	12.00%	0.23%
Marathon Oil Corp	MRO	677.58	22.58	15,299.85		1.42%			
Bio-Rad Laboratories Inc	BIO	24.63	417.14	10,275.83	0.04%			11.50%	0.00%
Ventas Inc	VTR	399.71	40.17	16,056.47	0.06%	4.48%	0.00%	10.50%	0.01%
VF Corp	VFC	388.50	29.91	11,619.89	0.05%	6.69%	0.00%	9.50%	0.00%
Vornado Realty Trust	VNO	191.78	23.16	4,441.51		9.15%		-20.50%	
Vulcan Materials Co	VMC	132.90	157.71	20,959.82	0.08%	1.01%	0.00%	8.50%	0.01%
Weyerhaeuser Co	WY	740.32	28.56	21,143.40	0.08%	2.52%	0.00%	7.00%	0.01%
Whirlpool Corp	WHR	54.51	134.81	7,348.22	0.03%	5.19%	0.00%	6.00%	0.00%
Williams Cos Inc/The	WMB	1,218.53	28.63	34,886.51	0.14%	5.94%	0.01%	8.50%	0.01%
Constellation Energy Corp	CEG	326.66	83.19	27,175.18		0.68%			
WEC Energy Group Inc	WEC	315.44	89.43	28,209.35	0.11%	3.25%	0.00%	6.00%	0.01%
Adobe Inc	ADBE	464.90	275.20	127,940.48	0.51%			14.50%	0.07%
AES Corp/The	AES	667.93	22.60	15,095.31	0.06%	2.80%	0.00%	14.00%	0.01%
Amgen Inc	AMGN	534.93	225.40	120,573.45	0.48%	3.44%	0.02%	5.50%	0.03%
Apple Inc	AAPL	16,070.75	138.20	2,220,977.93	8.86%	0.67%	0.06%	14.00%	1.24%
Autodesk Inc	ADSK	215.86	186.80	40,322.46	0.16%			14.00%	0.02%
Cintas Corp	CTAS	101.53	388.19	39,414.10	0.16%	1.18%	0.00%	13.50%	0.02%
Comcast Corp	CMCSA	4,403.79	29.33	129,163.28	0.52%	3.68%	0.02%	9.50%	0.05%
Molson Coors Beverage Co	TAP	200.37	47.99	9,615.56		3.17%		49.50%	
KLA Corp	KLAC	141.81	302.63	42,915.36		1.72%		23.00%	
Marriott International Inc/MD	MAR	324.55	140.14	45,482.58	0.18%	0.86%	0.00%	17.50%	0.03%
McCormick & Co Inc/MD	MKC	250.47	71.27	17,851.14	0.07%	2.08%	0.00%	5.50%	0.00%
PACCAR Inc	PCAR	347.72	83.69	29,100.60	0.12%	1.77%	0.00%	5.00%	0.01%
Costco Wholesale Corp	COST	442.66	472.27	209,056.93	0.83%	0.76%	0.01%	10.50%	0.09%
First Republic Bank/CA	FRC	182.72	130.55	23,853.44	0.10%	0.83%	0.00%	11.50%	0.01%
Stryker Corp	SYK	378.32	202.54	76,625.14	0.31%	1.37%	0.00%	8.50%	0.03%
Tyson Foods Inc	TSN	289.62	65.93	19,094.45	0.08%	2.79%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	143.72	77.38	11,121.21	0.04%	1.27%	0.00%	5.00%	0.00%
Applied Materials Inc	AMAT	860.31	81.93	70,485.12	0.28%	1.27%	0.00%	17.00%	0.05%
American Airlines Group Inc	AAL	649.85	12.04	7,824.15					
Cardinal Health Inc	CAH	262.01	66.68	17,471.03	0.07%	2.97%	0.00%	5.00%	0.00%
Cincinnati Financial Corp	CINF	159.20	89.57	14,259.45	0.06%	3.08%	0.00%	8.50%	0.00%
Paramount Global	PARA	608.42	19.04	11,584.34	0.05%	5.04%	0.00%	4.50%	0.00%
DR Horton Inc	DHI	347.48	67.35	23,402.85	0.09%	1.34%	0.00%	13.00%	0.01%
Electronic Arts Inc	EA	278.05	115.71	32,172.59	0.13%	0.66%	0.00%	11.50%	0.01%
Expeditors International of Washington Inc	EXPD	163.60	88.31	14,447.07	0.06%	1.52%	0.00%	10.00%	0.01%
Fastenal Co	FAST	574.68	46.04	26,458.22	0.11%	2.69%	0.00%	8.50%	0.01%
M&T Bank Corp	MTB	175.61	176.32	30,964.26	0.12%	2.72%	0.00%	8.00%	0.01%
Xcel Energy Inc	XEL	546.99	64.00	35,007.42	0.14%	3.05%	0.00%	6.00%	0.01%
Fiserv Inc	FISV	639.58	93.57	59,845.87	0.24%			11.00%	0.03%
Fifth Third Bancorp	FITB	686.19	31.96	21,930.63	0.09%	4.13%	0.00%	9.00%	0.01%
Gilead Sciences Inc	GILD	1,253.37	61.69	77,320.21	0.31%	4.73%	0.01%	12.00%	0.04%
Hasbro Inc	HAS	138.09	67.42	9,310.10	0.04%	4.15%	0.00%	11.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,442.19	13.18	19,008.12	0.08%	4.70%	0.00%	12.50%	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.
Welltower Inc	WELL	463.37	64.32	29,803.96	0.12%	3.79%	0.00%	3.50%	0.00%
Biogen Inc	BIIB	145.11	267.00	38,745.17				-10.50%	
Northern Trust Corp	NTRS	208.39	85.56	17,829.59	0.07%	3.51%	0.00%	8.00%	0.01%
Packaging Corp of America	PKG	93.74	112.29	10,526.06	0.04%	4.45%	0.00%	11.00%	0.00%
Paychex Inc	PAYX	360.40	112.21	40,440.60	0.16%	2.82%	0.00%	10.00%	0.02%
QUALCOMM Inc	QCOM	1,123.00	112.98	126,876.54	0.51%	2.66%	0.01%	19.00%	0.10%
Roper Technologies Inc	ROP	106.01	359.64	38,125.44	0.15%	0.69%	0.00%	3.50%	0.01%
Ross Stores Inc	ROST	347.06	84.27	29,247.00	0.12%	1.47%	0.00%	14.00%	0.02%
IDEXX Laboratories Inc	IDXX	83.25	325.80	27,124.15	0.11%			12.00%	0.01%
Starbucks Corp	SBUX	1,147.40	84.26	96,679.92	0.39%	2.52%	0.01%	16.50%	0.06%
KeyCorp	KEY	932.66	16.02	14,941.20	0.06%	4.87%	0.00%	9.00%	0.01%
Fox Corp	FOXA	305.37	30.68	9,368.66	0.04%	1.63%	0.00%	11.00%	0.00%
Fox Corp	FOX	241.57	28.50	6,884.83		1.75%			
State Street Corp	STT	367.62	60.81	22,354.91	0.09%	4.14%	0.00%	9.50%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	421.39	11.36	4,786.98					
US Bancorp	USB	1,485.78	40.32	59,906.81	0.24%	4.76%	0.01%	6.00%	0.01%
A O Smith Corp	AOS	128.48	48.58	6,241.41	0.02%	2.31%	0.00%	11.50%	0.00%
NortonLifeLock Inc	NLOK	666.03	20.14	13,413.74	0.05%	2.48%	0.00%	9.50%	0.01%
T Rowe Price Group Inc	TROW	225.69	105.01	23,699.92	0.09%	4.57%	0.00%	9.50%	0.01%
Waste Management Inc	WM	413.34	160.21	66,220.56	0.26%	1.62%	0.00%	6.50%	0.02%
Constellation Brands Inc	STZ	161.22	229.68	37,029.93	0.15%	1.39%	0.00%	5.00%	0.01%
DENTSPLY SIRONA Inc	XRAY	215.45	28.35	6,108.06	0.02%	1.76%	0.00%	12.00%	0.00%
Zions Bancorp NA	ZION	150.47	50.86	7,652.96	0.03%	3.22%	0.00%	6.50%	0.00%
Alaska Air Group Inc	ALK	126.77	39.15	4,962.85					
Invesco Ltd	IVZ	454.94	13.70	6,232.68	0.02%	5.47%	0.00%	14.00%	0.00%
Linde PLC	LIN	496.34	269.59	133,807.49	0.53%	1.74%	0.01%	12.00%	0.06%
Intuit Inc	INTU	281.87	387.32	109,173.89	0.44%	0.81%	0.00%	17.50%	0.08%
Morgan Stanley	MS	1,716.83	79.01	135,646.42	0.54%	3.92%	0.02%	10.50%	0.06%
Microchip Technology Inc	MCHP	552.48	61.03	33,718.10	0.13%	1.97%	0.00%	10.00%	0.01%
Chubb Ltd	CB	417.64	181.88	75,960.55	0.30%	1.83%	0.01%	14.50%	0.04%
Hologic Inc	HOLX	249.65	64.52	16,107.61				25.00%	
Citizens Financial Group Inc	CFG	495.64	34.36	17,030.29	0.07%	4.89%	0.00%	9.00%	0.01%
O'Reilly Automotive Inc	ORLY	63.32	703.35	44,534.72	0.18%			13.00%	0.02%
Allstate Corp/The	ALL	270.30	124.53	33,659.96	0.13%	2.73%	0.00%	2.50%	0.00%
Equity Residential	EQR	376.12	67.22	25,282.65		3.72%		-6.00%	
BorgWarner Inc	BWA	236.83	31.40	7,436.49	0.03%	2.17%	0.00%	9.50%	0.00%
Keurig Dr Pepper Inc	KDP	1,416.11	35.82	50,725.13	0.20%	2.23%	0.00%	11.50%	0.02%
Organon & Co	OGN	254.33	23.40	5,951.32		4.79%			
Host Hotels & Resorts Inc	HST	714.89	15.88	11,352.50		3.02%		59.50%	
Incyte Corp	INCY	222.43	66.64	14,822.80				25.50%	
Simon Property Group Inc	SPG	327.35	89.75	29,379.84	0.12%	7.80%	0.01%	3.00%	0.00%
Eastman Chemical Co	EMN	122.81	71.05	8,725.58	0.03%	4.28%	0.00%	9.50%	0.00%
Twitter Inc	TWTR	765.25	43.84	33,548.38					
AvalonBay Communities Inc	AVB	139.83	184.19	25,755.47	0.10%	3.45%	0.00%	8.00%	0.01%
Prudential Financial Inc	PRU	372.60	85.78	31,961.63	0.13%	5.60%	0.01%	5.50%	0.01%
United Parcel Service Inc	UPS	731.85	161.54	118,223.70	0.47%	3.76%	0.02%	11.50%	0.05%
Walgreens Boots Alliance Inc	WBA	864.26	31.40	27,137.67	0.11%	6.11%	0.01%	7.50%	0.01%
STERIS PLC	STE	100.02	166.28	16,630.49	0.07%	1.13%	0.00%	11.50%	0.01%
McKesson Corp	MCK	143.73	339.87	48,849.52	0.19%	0.64%	0.00%	10.00%	0.02%
Lockheed Martin Corp	LMT	265.15	386.29	102,425.57	0.41%	3.11%	0.01%	7.00%	0.03%
AmerisourceBergen Corp	ABC	207.26	135.33	28,048.23	0.11%	1.36%	0.00%	8.50%	0.01%
Capital One Financial Corp	COF	383.82	92.17	35,376.51		2.60%			
Waters Corp	WAT	59.88	269.53	16,138.38	0.06%			6.00%	0.00%
Nordson Corp	NDSN	57.21	212.27	12,144.18	0.05%	1.22%	0.00%	12.00%	0.01%
Dollar Tree Inc	DLTR	223.94	136.10	30,477.83	0.12%			12.00%	0.01%
Darden Restaurants Inc	DRI	122.58	126.32	15,484.31		3.83%		21.00%	
Match Group Inc	MTCH	282.99	47.75	13,512.58				21.00%	
Domino's Pizza Inc	DPZ	35.89	310.20	11,131.53	0.04%	1.42%	0.00%	14.50%	0.01%
NVR Inc	NVR	3.28	3,987.08	13,089.58	0.05%			5.50%	0.00%
NetApp Inc	NTAP	217.37	61.85	13,444.09	0.05%	3.23%	0.00%	8.00%	0.00%
DXC Technology Co	DXC	229.88	24.48	5,627.39	0.02%			12.00%	0.00%
Old Dominion Freight Line Inc	ODFL	111.77	248.77	27,806.02	0.11%	0.48%	0.00%	11.50%	0.01%
DaVita Inc	DVA	91.30	82.77	7,556.90	0.03%			11.00%	0.00%
Hartford Financial Services Group Inc/The	HIG	323.14	61.94	20,015.42	0.08%	2.49%	0.00%	6.50%	0.01%
Iron Mountain Inc	IRM	290.69	43.97	12,781.42	0.05%	5.63%	0.00%	11.00%	0.01%
Estee Lauder Cos Inc/The	EL	231.55	215.90	49,990.78	0.20%	1.11%	0.00%	14.00%	0.03%
Cadence Design Systems Inc	CDNS	273.87	163.43	44,758.57	0.18%			12.00%	0.02%
Tyler Technologies Inc	TYL	41.58	347.50	14,449.40	0.06%			12.00%	0.01%
Universal Health Services Inc	UHS	65.72	88.18	5,794.93	0.02%	0.91%	0.00%	7.00%	0.00%
Skyworks Solutions Inc	SWKS	160.45	85.27	13,681.23	0.05%	2.91%	0.00%	13.00%	0.01%
Quest Diagnostics Inc	DGX	116.61	122.03	14,229.44	0.06%	2.16%	0.00%	3.50%	0.00%
Activision Blizzard Inc	ATVI	782.31	74.34	58,156.70	0.23%	0.63%	0.00%	14.00%	0.03%
Rockwell Automation Inc	ROK	115.44	215.11	24,831.22	0.10%	2.08%	0.00%	9.50%	0.01%
Kraft Heinz Co/The	KHC	1,225.44	33.35	40,868.42	0.16%	4.80%	0.01%	5.50%	0.01%
American Tower Corp	AMT	465.59	214.70	99,961.53	0.40%	2.74%	0.01%	9.00%	0.04%
Regeneron Pharmaceuticals Inc	REGN	107.19	688.87	73,839.98	0.29%			3.00%	0.01%
Amazon.com Inc	AMZN	10,187.56	113.00	1,151,193.72				26.50%	
Jack Henry & Associates Inc	JKHY	72.90	182.27	13,288.03	0.05%	1.08%	0.00%	9.00%	0.00%
Ralph Lauren Corp	RL	42.90	84.93	3,643.33	0.01%	3.53%	0.00%	12.50%	0.00%
Boston Properties Inc	BXP	156.74	74.97	11,750.42		5.23%		-1.00%	
Amphenol Corp	APH	594.83	66.96	39,829.68	0.16%	1.19%	0.00%	13.00%	0.02%
Howmet Aerospace Inc	HWM	415.40	30.93	12,848.41	0.05%	0.52%	0.00%	12.00%	0.01%
Pioneer Natural Resources Co	PXD	238.67	216.53	51,678.57		15.83%		21.00%	
Valero Energy Corp	VLO	393.97	106.85	42,095.69	0.17%	3.67%	0.01%	11.00%	0.02%
Synopsys Inc	SNPS	152.91	305.51	46,715.84	0.19%			12.50%	0.02%
Etsy Inc	ETSY	126.61	100.13	12,677.36				24.50%	
CH Robinson Worldwide Inc	CHRW	123.88	96.31	11,931.17	0.05%	2.28%	0.00%	8.50%	0.00%
Accenture PLC	ACN	664.19	257.30	170,895.57	0.68%	1.74%	0.01%	12.50%	0.09%
TransDigm Group Inc	TDG	54.24	524.82	28,463.61	0.11%			19.50%	0.02%
Yum! Brands Inc	YUM	284.54	106.34	30,258.20	0.12%	2.14%	0.00%	10.50%	0.01%
Prologis Inc	PLD	740.34	101.60	75,218.95	0.30%	3.11%	0.01%	6.00%	0.02%
FirstEnergy Corp	FE	571.40	37.00	21,141.62	0.08%	4.22%	0.00%	3.00%	0.00%

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.
VeriSign Inc	VRSN	107.28	173.70	18,635.06	0.07%			11.00%	0.01%
Quanta Services Inc	PWR	143.02	127.39	18,219.70	0.07%	0.22%	0.00%	12.50%	0.01%
Henry Schein Inc	HSIC	136.12	65.77	8,952.28	0.04%			7.00%	0.00%
Ameren Corp	AEE	258.09	80.55	20,789.31	0.08%	2.93%	0.00%	6.50%	0.01%
ANSYS Inc	ANSS	87.07	221.70	19,303.20	0.08%			8.50%	0.01%
FactSet Research Systems Inc	FDS	37.98	400.11	15,196.18	0.06%	0.89%	0.00%	10.50%	0.01%
NVIDIA Corp	NVDA	2,490.00	121.39	302,261.10		0.13%		23.00%	
Sealed Air Corp	SEE	145.23	44.51	6,464.05	0.03%	1.80%	0.00%	10.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	517.79	57.44	29,741.57	0.12%	1.88%	0.00%	7.50%	0.01%
SVB Financial Group	SIVB	59.08	335.78	19,838.55	0.08%			6.50%	0.01%
Intuitive Surgical Inc	ISRG	357.11	187.44	66,936.89	0.27%			12.50%	0.03%
Take-Two Interactive Software Inc	TTWO	166.49	109.00	18,147.30	0.07%			10.50%	0.01%
Republic Services Inc	RSG	315.93	136.04	42,979.53	0.17%	1.46%	0.00%	12.50%	0.02%
eBay Inc	EBAY	549.37	36.81	20,222.24	0.08%	2.39%	0.00%	15.50%	0.01%
Goldman Sachs Group Inc/The	GS	341.36	293.05	100,034.38	0.40%	3.41%	0.01%	5.00%	0.02%
SBA Communications Corp	SBAC	107.88	284.65	30,707.47		1.00%		35.50%	
Sempra Energy	SRE	314.31	149.94	47,127.64	0.19%	3.05%	0.01%	7.50%	0.01%
Moody's Corp	MCO	183.50	243.11	44,610.69	0.18%	1.15%	0.00%	8.00%	0.01%
ON Semiconductor Corp	ON	433.24	62.33	27,003.60				22.50%	
Booking Holdings Inc	BKNG	39.71	1,643.21	65,245.30				22.00%	
F5 Inc	FFIV	59.56	144.73	8,620.41	0.03%			10.00%	0.00%
Akamai Technologies Inc	AKAM	158.96	80.32	12,767.43	0.05%			5.50%	0.00%
Charles River Laboratories International Inc	CRL	50.86	196.80	10,009.84	0.04%			12.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.64	222.49	8,374.52	0.03%	1.26%	0.00%	11.00%	0.00%
Devon Energy Corp	DVN	654.80	60.13	39,373.12		10.31%		30.00%	
Bio-Techne Corp	TECH	39.22	284.00	11,139.33	0.04%	0.45%	0.00%	17.50%	0.01%
Alphabet Inc	GOOGL	5,996.00	95.65	573,517.40					
Teleflex Inc	TFX	46.91	201.46	9,449.48	0.04%	0.68%	0.00%	10.00%	0.00%
Netflix Inc	NFLX	444.71	235.44	104,701.58	0.42%			14.50%	0.06%
Allegion plc	ALLE	87.84	89.68	7,877.31	0.03%	1.83%	0.00%	10.50%	0.00%
Agilent Technologies Inc	A	296.04	121.34	35,921.61	0.14%	0.69%	0.00%	12.00%	0.02%
Warner Bros Discovery Inc	WBD	2,427.59	11.50	27,917.32					
Elevance Health Inc	ELV	240.00	454.24	109,018.05	0.44%	1.13%	0.00%	12.50%	0.05%
Trimble Inc	TRMB	247.66	54.27	13,440.35	0.05%			10.00%	0.01%
CME Group Inc	CME	359.43	177.13	63,666.37	0.25%	2.26%	0.01%	8.50%	0.02%
Juniper Networks Inc	JNPR	322.61	26.12	8,426.55	0.03%	3.22%	0.00%	9.00%	0.00%
BlackRock Inc	BLK	150.77	550.28	82,965.17	0.33%	3.55%	0.01%	10.00%	0.03%
DTE Energy Co	DTE	193.74	115.05	22,290.02	0.09%	3.08%	0.00%	4.50%	0.00%
Nasdaq Inc	NDAQ	491.23	56.68	27,842.69	0.11%	1.41%	0.00%	6.00%	0.01%
Celanese Corp	CE	108.35	90.34	9,788.25	0.04%	3.01%	0.00%	7.50%	0.00%
Philip Morris International Inc	PM	1,550.16	83.01	128,679.03	0.51%	6.12%	0.03%	7.00%	0.04%
Salesforce Inc	CRM	1,000.00	143.84	143,840.00	0.57%			19.50%	0.11%
Ingersoll Rand Inc	IR	403.18	43.26	17,441.61		0.18%			
Huntington Ingalls Industries Inc	HII	39.95	221.50	8,848.48	0.04%	2.13%	0.00%	10.00%	0.00%
MetLife Inc	MET	797.61	60.78	48,478.98	0.19%	3.29%	0.01%	7.50%	0.01%
Tapestry Inc	TPR	242.05	28.43	6,881.48	0.03%	4.22%	0.00%	10.00%	0.00%
CSX Corp	CSX	2,141.24	26.64	57,042.66	0.23%	1.50%	0.00%	10.50%	0.02%
Edwards Lifesciences Corp	EW	619.94	82.63	51,225.89	0.20%			12.00%	0.02%
Ameriprise Financial Inc	AMP	108.17	251.95	27,252.42	0.11%	1.98%	0.00%	12.50%	0.01%
Zebra Technologies Corp	ZBRA	51.79	262.01	13,569.50	0.05%			11.50%	0.01%
Zimmer Biomet Holdings Inc	ZBH	209.82	104.55	21,936.68	0.09%	0.92%	0.00%	7.00%	0.01%
CBRE Group Inc	CBRE	321.17	67.51	21,682.25	0.09%			8.50%	0.01%
Camden Property Trust	CPT	106.53	119.45	12,724.77	0.05%	3.15%	0.00%	4.50%	0.00%
Mastercard Inc	MA	958.68	284.34	272,589.93	1.09%	0.69%	0.01%	18.50%	0.20%
CarMax Inc	KMX	158.02	66.02	10,432.15	0.04%			13.00%	0.01%
Intercontinental Exchange Inc	ICE	558.46	90.35	50,456.68	0.20%	1.68%	0.00%	6.50%	0.01%
Fidelity National Information Services Inc	FIS	607.98	75.57	45,944.97		2.49%		52.00%	
Chipotle Mexican Grill Inc	CMG	27.77	1,502.76	41,724.13				22.50%	
Wynn Resorts Ltd	WYNN	113.73	63.03	7,168.40				27.00%	
Live Nation Entertainment Inc	LYV	229.97	76.04	17,487.07					
Assurant Inc	AIZ	53.21	145.27	7,729.67	0.03%	1.87%	0.00%	15.50%	0.00%
NRG Energy Inc	NRG	235.15	38.27	8,999.08		3.66%		-10.50%	
Regions Financial Corp	RF	934.40	20.07	18,753.33	0.07%	3.99%	0.00%	11.50%	0.01%
Monster Beverage Corp	MNST	526.89	86.96	45,817.92	0.18%			11.50%	0.02%
Mosaic Co/The	MOS	345.27	48.33	16,686.75		1.24%		38.00%	
Baker Hughes Co	BKR	1,011.75	20.96	21,206.36		3.44%			
Expedia Group Inc	EXPE	152.04	93.69	14,244.16					
Evergy Inc	EVRG	229.48	59.40	13,630.99	0.05%	3.86%	0.00%	7.50%	0.00%
CF Industries Holdings Inc	CF	199.26	96.25	19,178.87		1.66%		32.00%	
Leidos Holdings Inc	LDOS	136.54	87.47	11,943.24	0.05%	1.65%	0.00%	8.50%	0.00%
APA Corp	APA	326.53	34.19	11,164.06		2.92%			
Alphabet Inc	GOOG	6,163.00	96.15	592,572.45	2.36%			18.50%	0.44%
TE Connectivity Ltd	TEL	319.84	110.36	35,297.43	0.14%	2.03%	0.00%	10.50%	0.01%
Cooper Cos Inc/The	COO	49.35	263.90	13,022.41	0.05%	0.02%	0.00%	14.00%	0.01%
Discover Financial Services	DFS	273.17	90.92	24,836.71	0.10%	2.64%	0.00%	16.00%	0.02%
Visa Inc	V	1,635.02	177.65	290,460.41	1.16%	0.84%	0.01%	13.50%	0.16%
Mid-America Apartment Communities Inc	MAA	115.44	155.07	17,901.13	0.07%	3.22%	0.00%	4.50%	0.00%
Xylem Inc/NY	XYL	180.18	87.36	15,740.70	0.06%	1.37%	0.00%	9.00%	0.01%
Marathon Petroleum Corp	MPC	498.62	99.33	49,528.32		2.34%			
Tractor Supply Co	TSCO	111.00	185.88	20,632.68	0.08%	1.98%	0.00%	12.50%	0.01%
Advanced Micro Devices Inc	AMD	1,614.32	63.36	102,283.38				25.50%	
ResMed Inc	RMD	146.43	218.30	31,964.58	0.13%	0.81%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	22.51	1,084.12	24,400.29	0.10%			12.50%	0.01%
VICI Properties Inc	VICI	963.09	29.85	28,748.33	0.11%	5.23%	0.01%	8.50%	0.01%
Copart Inc	CPRT	238.06	106.40	25,329.26	0.10%			12.00%	0.01%
Jacobs Solutions Inc	J	127.61	108.49	13,843.97	0.06%	0.85%	0.00%	12.00%	0.01%
Albemarle Corp	ALB	117.13	264.44	30,973.59	0.12%	0.60%	0.00%	15.00%	0.02%
Fortinet Inc	FTNT	788.52	49.13	38,740.04				21.50%	
Moderna Inc	MRNA	391.20	118.25	46,259.40				-2.50%	
Essex Property Trust Inc	ESS	65.12	242.23	15,774.99		3.63%		-4.00%	
CoStar Group Inc	CSGP	406.55	69.65	28,316.35	0.11%			13.00%	0.01%
Realty Income Corp	O	617.58	58.20	35,942.98	0.14%	5.11%	0.01%	6.00%	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.
Westrock Co	WRK	254.30	30.89	7,855.27	0.03%	3.24%	0.00%	20.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	181.88	81.35	14,795.53	0.06%	0.74%	0.00%	9.50%	0.01%
Pool Corp	POOL	39.59	318.21	12,598.25	0.05%	1.26%	0.00%	14.00%	0.01%
Western Digital Corp	WDC	314.49	32.55	10,236.75	0.04%			20.00%	0.01%
PepsiCo Inc	PEP	1,380.09	163.26	225,312.68	0.90%	2.82%	0.03%	6.00%	0.05%
Diamondback Energy Inc	FANG	177.79	120.46	21,415.98		10.13%			
ServiceNow Inc	NOW	202.00	377.61	76,277.22				45.50%	
Church & Dwight Co Inc	CHD	242.91	71.44	17,353.42	0.07%	1.47%	0.00%	6.00%	0.00%
Federal Realty Investment Trust	FRT	80.91	90.12	7,291.43	0.03%	4.79%	0.00%	2.50%	0.00%
MGM Resorts International	MGM	393.10	29.72	11,682.99		0.03%		25.00%	
American Electric Power Co Inc	AEP	513.73	86.45	44,412.30	0.18%	3.61%	0.01%	6.50%	0.01%
SolarEdge Technologies Inc	SEDG	55.64	231.46	12,877.28				22.00%	
Invitation Homes Inc	INVH	610.36	33.77	20,611.86		2.61%			
PTC Inc	PTC	117.47	104.60	12,286.94				29.00%	
JB Hunt Transport Services Inc	JBHT	103.81	156.42	16,238.43	0.06%	1.02%	0.00%	11.50%	0.01%
Lam Research Corp	LRCX	136.84	366.00	50,081.61	0.20%	1.89%	0.00%	20.00%	0.04%
Mohawk Industries Inc	MHK	63.53	91.19	5,793.67	0.02%			10.00%	0.00%
Pentair PLC	PNR	164.46	40.63	6,682.01	0.03%	2.07%	0.00%	13.00%	0.00%
Vertex Pharmaceuticals Inc	VRTX	256.46	289.54	74,255.14	0.30%			12.50%	0.04%
Amcor PLC	AMCR	1,489.02	10.73	15,977.18	0.06%	4.47%	0.00%	14.50%	0.01%
Meta Platforms Inc	META	2,280.67	135.68	309,441.58	1.23%			16.00%	0.20%
T-Mobile US Inc	TMUS	1,254.04	134.17	168,254.68	0.67%			10.00%	0.07%
United Rentals Inc	URI	69.99	270.12	18,904.35	0.08%			18.00%	0.01%
ABIOMED Inc	ABMD	45.46	245.66	11,167.95	0.04%			7.50%	0.00%
Honeywell International Inc	HON	673.69	166.97	112,486.35	0.45%	2.47%	0.01%	11.00%	0.05%
Alexandria Real Estate Equities Inc	ARE	163.17	140.19	22,874.52	0.09%	3.37%	0.00%	10.00%	0.01%
Delta Air Lines Inc	DAL	641.20	28.06	17,992.02					
Seagate Technology Holdings PLC	STX	208.03	53.23	11,073.44	0.04%	5.26%	0.00%	15.00%	0.01%
United Airlines Holdings Inc	UAL	326.73	32.53	10,628.49					
News Corp	NWS	195.82	15.42	3,019.61		1.30%			
Centene Corp	CNC	571.58	77.81	44,474.72	0.18%			10.00%	0.02%
Martin Marietta Materials Inc	MLM	62.37	322.09	20,090.04	0.08%	0.82%	0.00%	5.50%	0.00%
Teradyne Inc	TER	156.78	75.15	11,782.17	0.05%	0.59%	0.00%	8.50%	0.00%
PayPal Holdings Inc	PYPL	1,156.48	86.07	99,537.89	0.40%			12.00%	0.05%
Tesla Inc	TSLA	3,133.47	265.25	831,152.92				52.00%	
DISH Network Corp	DISH	291.87	13.83	4,036.56	0.02%			2.50%	0.00%
Dow Inc	DOW	718.17	43.93	31,549.08	0.13%	6.37%	0.01%	15.00%	0.02%
Everest Re Group Ltd	RE	39.41	262.44	10,342.76	0.04%	2.51%	0.00%	17.50%	0.01%
Teledyne Technologies Inc	TDY	46.87	337.47	15,815.53	0.06%			11.50%	0.01%
News Corp	NWSA	385.60	15.11	5,826.39		1.32%			
Exelon Corp	EXC	991.76	37.46	37,151.22		3.60%			
Global Payments Inc	GPN	277.16	108.05	29,947.46	0.12%	0.93%	0.00%	17.00%	0.02%
Crown Castle Inc	CCI	433.04	144.55	62,595.79	0.25%	4.07%	0.01%	12.00%	0.03%
Aptiv PLC	APTV	270.93	78.21	21,189.67				26.00%	
Advance Auto Parts Inc	AAP	60.12	156.34	9,398.85	0.04%	3.84%	0.00%	16.00%	0.01%
Align Technology Inc	ALGN	78.11	207.11	16,176.95	0.06%			17.00%	0.01%
Illumina Inc	ILMN	157.30	190.79	30,011.27	0.12%			6.50%	0.01%
LKQ Corp	LKQ	274.39	47.15	12,937.49	0.05%	2.12%	0.00%	13.00%	0.01%
Nielsen Holdings PLC	NLSN	359.83	27.72	9,974.60		0.87%			
Zoetis Inc	ZTS	468.14	148.29	69,420.33	0.28%	0.88%	0.00%	11.00%	0.03%
Equinix Inc	EQIX	91.08	568.84	51,807.10	0.21%	2.18%	0.00%	15.00%	0.03%
Digital Realty Trust Inc	DLR	287.41	99.18	28,505.13		4.92%		-3.50%	
Las Vegas Sands Corp	LVS	764.16	37.52	28,671.13	0.11%			13.50%	0.02%
Molina Healthcare Inc	MOH	58.10	329.84	19,163.70	0.08%			11.00%	0.01%

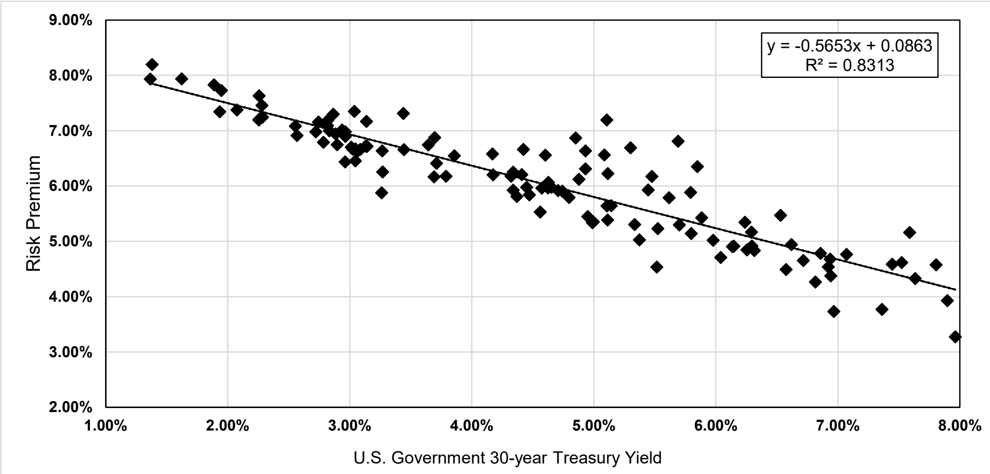
Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of September 30, 2022
[5] Source: Bloomberg Professional as of September 30, 2022
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of September 30, 2022
[9] Equals [7] x [8]
[10] Source: Value Line, as of September 30, 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%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
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%
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%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
AVERAGE	10.61%	4.56%	6.05%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.911763
R Square	0.831312
Adjusted R Square	0.829918
Standard Error	0.004255
Observations	123

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010796	0.010796	596.302374	0.000000
Residual	121	0.002191	0.000018		
Total	122	0.012986			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0863	0.0011	76.8103	0.0000	0.0841	0.0885	0.0841	0.0885
U.S. Govt. 30-year Treasury	(0.5653)	0.0232	(24.4193)	0.0000	(0.6112)	(0.5195)	(0.6112)	(0.5195)

	U.S. Govt. 30-year Treasury	Risk Premium	ROE
	[7]	[8]	[9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.47%	6.67%	10.14%
Blue Chip Near-Term Projected Forecast (Q1 2023 - Q1 2024) [5]	3.88%	6.44%	10.32%
Blue Chip Long-Term Projected Forecast (2024-2028) [6]	3.80%	6.48%	10.28%
AVERAGE			10.24%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 30, 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 September 30, 2022
[5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 10, September 30, 2022, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086293 + (-0.565341 x Column [7])
[9] Equals Column [7] + Column [8]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
ALLETE, Inc.	ALE	3.33	1.24
Alliant Energy Corporation	LNT	15.29	2.49
Ameren Corporation	AEE	23.78	2.41
American Electric Power Company, Inc.	AEP	51.49	2.14
Duke Energy Corporation	DUK	81.99	1.72
Entergy Corporation	ETR	23.47	2.00
Evergy, Inc.	EVRG	15.54	1.67
IDACORP, Inc.	IDA	5.52	2.04
NextEra Energy, Inc.	NEE	169.25	4.64
NorthWestern Corporation	NWE	3.01	1.22
OGE Energy Corporation	OGE	8.16	1.92
Otter Tail Corporation	OTTR	3.02	2.70
Portland General Electric Company	POR	4.55	1.66
Southern Company	SO	81.86	2.85
Xcel Energy Inc.	XEL	40.30	2.52
Average		35.37	2.22
Median		15.54	2.04

MDU-MT		
Common Equity ($ millions) [3]	$	124.24
Implied Market Capitalization [4]	$	253.23
As a percent of Proxy Group Median Market Capitalization		1.63%

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10	[5] Market Capitalization of Largest Company ($ millions)	[6] Size Premium
1-Largest	2,324,390.22	-0.22%
2	36,099.22	0.43%
3	16,738.36	0.55%
4	8,212.64	0.54%
5	5,003.75	0.89%
6	3,276.55	1.18%
7	2,164.52	1.34%
8	1,306.04	1.21%
9	627.80	2.10%
10-Smallest	289.01	4.80%
MDU-MT - Implied Market Capitalization	253.23	4.80%
Proxy Group Median	15,537.26	0.55%
Size Premium [7]		4.25%

Notes:
[1] Source: S&P Capital IQ Pro, equals 30-day average as of September 30, 2022
[2] Source: S&P Capital IQ Pro; equals 30-day average as of September 30, 2022
[3] Data provided by MDU
[4] Equals [3] x proxy group median market-to-book ratio
[5] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2021
[6] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2021
[7] Equals 4.80% − 0.55%

FLOTATION COST ADJUSTMENT -- MONTANA-DAKOTA UTILITIES 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	58.39	4.45%	4.62%	4.80%	6.00%	8.70%	8.10%	7.60%	12.22%	12.40%
Alliant Energy Corporation	LNT	1.71	60.91	2.81%	2.89%	3.00%	6.00%	6.30%	6.20%	6.17%	9.06%	9.17%
Ameren Corporation	AEE	2.36	91.83	2.57%	2.66%	2.76%	6.50%	6.37%	7.20%	6.69%	9.35%	9.45%
American Electric Power Company, Inc.	AEP	3.12	100.22	3.11%	3.21%	3.33%	6.50%	6.25%	6.10%	6.28%	9.49%	9.62%
Duke Energy Corporation	DUK	4.02	106.48	3.78%	3.88%	4.03%	5.00%	5.62%	6.10%	5.57%	9.45%	9.60%
Entergy Corporation	ETR	4.04	115.37	3.50%	3.60%	3.74%	4.00%	6.19%	6.80%	5.66%	9.26%	9.40%
Evergy, Inc.	EVRG	2.29	67.69	3.38%	3.48%	3.61%	7.50%	3.71%	5.20%	5.47%	8.95%	9.08%
IDACORP, Inc.	IDA	3.00	109.12	2.75%	2.79%	2.90%	4.00%	2.70%	2.70%	3.13%	5.93%	6.03%
NextEra Energy, Inc.	NEE	1.70	86.05	1.98%	2.07%	2.15%	10.00%	9.35%	9.70%	9.68%	11.75%	11.83%
NorthWestern Corporation	NWE	2.52	53.30	4.73%	4.80%	4.98%	3.00%	4.50%	1.70%	3.07%	7.87%	8.05%
OGE Energy Corporation	OGE	1.64	40.75	4.02%	4.10%	4.26%	6.50%	1.90%	3.50%	3.97%	8.07%	8.23%
Otter Tail Corporation	OTTR	1.65	72.44	2.28%	2.35%	2.44%	4.50%	9.00%	n/a	6.75%	9.10%	9.19%
Portland General Electric Company	POR	1.81	50.58	3.58%	3.65%	3.79%	4.50%	3.16%	4.60%	4.09%	7.74%	7.88%
Southern Company	SO	2.72	77.01	3.53%	3.63%	3.77%	6.50%	6.59%	4.00%	5.70%	9.33%	9.47%
Xcel Energy Inc.	XEL	1.95	73.40	2.66%	2.74%	2.85%	6.00%	7.04%	6.40%	6.48%	9.22%	9.33%
Mean											9.12%	9.25%
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 September 30, 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])

2023-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2021 NET PLANT
($ Millions)

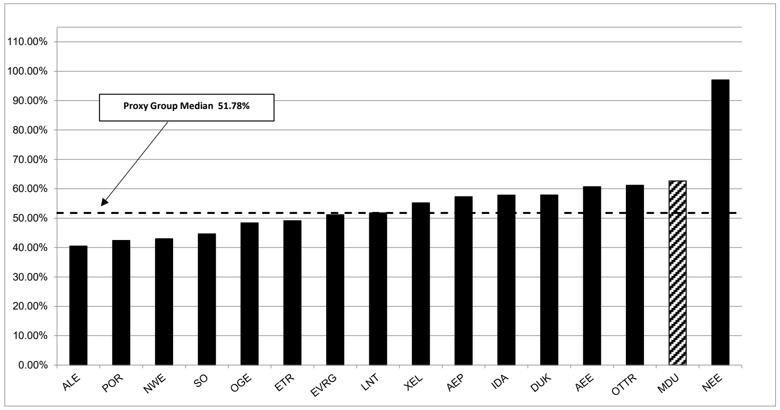
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2021	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2021 Net Plant
ALLETE, Inc.	ALE							
Capital Spending per Share			$5.95	$6.60	$7.25	$7.25	$7.25	
Common Shares Outstanding			58.00	59.50	61.00	61.00	61.00	
Capital Expenditures			$345.1	$392.7	$442.3	$442.3	$442.3	40.48%
Net Plant		$5,100.2						
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.90	$6.08	$6.25	$6.25	$6.25	
Common Shares Outstanding			251.50	252.25	253.00	253.00	253.00	
Capital Expenditures			$1,483.9	$1,532.4	$1,581.3	$1,581.3	$1,581.3	51.78%
Net Plant		$14,987.0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.55	$12.78	$13.00	$13.00	$13.00	
Common Shares Outstanding			267.00	273.50	280.00	280.00	280.00	
Capital Expenditures			$3,350.9	$3,494.0	$3,640.0	$3,640.0	$3,640.0	60.71%
Net Plant		$29,261.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.15	$14.08	$14.00	$14.00	$14.00	
Common Shares Outstanding			523.00	534.00	545.00	545.00	545.00	
Capital Expenditures			$7,400.5	$7,516.1	$7,630.0	$7,630.0	$7,630.0	57.28%
Net Plant		$66,001.0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$16.75	$16.75	$16.75	$16.75	$16.75	
Common Shares Outstanding			770.00	770.00	770.00	770.00	770.00	
Capital Expenditures			$12,897.5	$12,897.5	$12,897.5	$12,897.5	$12,897.5	57.88%
Net Plant		$111,408.0						
Entergy Corporation	ETR							
Capital Spending per Share			$19.00	$19.38	$19.75	$19.75	$19.75	
Common Shares Outstanding			209.00	211.50	214.00	214.00	214.00	
Capital Expenditures			$3,971.0	$4,097.8	$4,226.5	$4,226.5	$4,226.5	49.12%
Net Plant		$42,244.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$9.20	$9.35	$9.50	$9.50	$9.50	
Common Shares Outstanding			230.00	230.00	230.00	230.00	230.00	
Capital Expenditures			$2,116.0	$2,150.5	$2,185.0	$2,185.0	$2,185.0	51.17%
Net Plant		$21,150.0						
IDACORP, Inc	IDA							
Capital Spending per Share			$13.25	$11.63	$10.00	$10.00	$10.00	
Common Shares Outstanding			51.00	51.50	52.00	52.00	52.00	
Capital Expenditures			$675.8	$598.7	$520.0	$520.0	$520.0	57.82%
Net Plant		$4,901.8						
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$8.40	$9.20	$10.00	$10.00	$10.00	
Common Shares Outstanding			2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	
Capital Expenditures			$17,010.0	$18,630.0	$20,250.0	$20,250.0	$20,250.0	97.02%
Net Plant		$99,348.0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$9.10	$7.80	$6.50	$6.50	$6.50	
Common Shares Outstanding			62.00	62.00	62.00	62.00	62.00	
Capital Expenditures			$564.2	$483.6	$403.0	$403.0	$403.0	43.01%
Net Plant		$5,247.2						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200.20	200.20	200.20	200.20	
Capital Expenditures			$951.0	$951.0	$951.0	$951.0	$951.0	48.36%
Net Plant		$9,832.9						
Otter Tail Corporation	OTTR							
Capital Spending per Share			$5.90	$6.08	$6.25	$6.25	$6.25	
Common Shares Outstanding			$41.90	42.20	$42.50	42.50	42.50	
Capital Expenditures			$247.2	$256.4	$265.6	$265.6	$265.6	61.21%
Net Plant		$2,124.6						
Portland General Electric Company	POR							
Capital Spending per Share			$7.55	$7.58	$7.60	$7.60	$7.60	
Common Shares Outstanding			89.50	89.50	89.50	89.50	89.50	
Capital Expenditures			$675.7	$678.0	$680.2	$680.2	$680.2	42.40%
Net Plant		$8,005.0						
Southern Company	SO							
Capital Spending per Share			$7.85	$7.68	$7.50	$7.50	$7.50	
Common Shares Outstanding			1,070.00	1,070.00	1,070.00	1,070.00	1,070.00	
Capital Expenditures			$8,399.5	$8,212.3	$8,025.0	$8,025.0	$8,025.0	44.66%

2023-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2021 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2021	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2021 Net Plant
Net Plant		$91,108.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$9.00	$9.00	$9.00	$9.00	$9.00	
Common Shares Outstanding			550.00	555.50	561.00	561.00	561.00	
Capital Expenditures			$4,950.0	$4,999.5	$5,049.0	$5,049.0	$5,049.0	55.21%
Net Plant		$45,457.0						
Montana Dakota Utilities	MDU							
Capital Expenditures [8]			$38.1	$22.9	$38.1	$41.9	$17.6	62.66%
Net Electric Plant in Service [9]		$253.2						
			MDU CapEx Total (2023-2027)					$158.6
			MDU CapEx Annual Average					$31.7
			Proxy Group Median					51.78%
			MDU as % Proxy Group Median					1.21

Notes:
[1] - [6] Value Line July 22, 2022, Aug 12, 2022, September 09,2022.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] & [9] Data provided by MDU.

2023-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2021 NET PLANT



Projected CAPEX / 2021 Net Plant

	Company		2023-2027
1	ALLETE, Inc.	ALE	40.48%
2	Portland General Electric Company	POR	42.40%
3	NorthWestern Corporation	NWE	43.01%
4	Southern Company	SO	44.66%
5	OGE Energy Corporation	OGE	48.36%
6	Entergy Corporation	ETR	49.12%
7	Evergy, Inc.	EVRG	51.17%
8	Alliant Energy Corporation	LNT	51.78%
9	Xcel Energy Inc.	XEL	55.21%
10	American Electric Power Company, Inc.	AEP	57.28%
11	IDACORP, Inc	IDA	57.82%
12	Duke Energy Corporation	DUK	57.88%
13	Ameren Corporation	AEE	60.71%
14	Otter Tail Corporation	OTTR	61.21%
15	Montana Dakota Utilities	MDU	62.66%
16	NextEra Energy, Inc.	NEE	97.02%
	Proxy Group Median		51.78%
	MDU / Proxy Group		1.21

Notes:
Source: Schedule 11 pages 1-2 col. [7]

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
						Non-Volumetric Rate Design				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Electric fuel/gas commodity/purchase power	Test Year	Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design	Capital Cost Recovery
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Yes	Fully Forecast	No	No	No	No	Yes
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Yes	Historical	No	No	No	No	Yes
	Interstate Power & Light Co.	Iowa	Gas	Yes	Historical	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Yes	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Yes	Fully Forecast	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	N/A	Historical	Partial	Yes	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Yes - Sharing Band	Historical	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Yes	Historical	Partial	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Yes	Historical	Partial	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Yes	Historical	Partial	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	N/A	Partially Forecast	Partial	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Yes	Historical	Partial	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Yes	Fully Forecast	No	No	No	No	No
	AEP Texas	Texas	Electric	N/A	Historical	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Yes	Historical	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Yes	Historical	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Yes	Historical	No	No	No	No	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Yes	Fully Forecast	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Yes	Historical	Partial	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Yes	Historical	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Yes	Historical	Full	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	N/A	Partially Forecast	Partial	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Yes	Partially Forecast	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Yes	Historical	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Yes	Historical	Partial	No	No	Yes	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Yes	Fully Forecast	Partial	No	No	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Yes	Fully Forecast	Partial	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Yes	Partially Forecast	No	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Yes	Partially Forecast	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Yes	Historical	Partial	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Yes	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Yes	Fully Forecast	Partial	Yes	No	Yes	No
	Entergy Texas Inc.	Texas	Electric	Yes	Historical	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Yes	Historical	Partial	No	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Yes	Historical	No	No	No	No	Yes
	Evergy Metro Inc	Missouri	Electric	Yes - Sharing Band	Historical	Partial	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Yes - Sharing Band	Historical	Partial	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Yes - Sharing Band	Partially Forecast	Full	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Yes - Sharing Band	Partially Forecast	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Yes	Fully Forecast	No	No	No	No	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Yes	Fully Forecast	No	No	No	No	Yes
	Lone Star Transmission LLC	Texas	Electric	N/A	Historical	No	No	No	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Yes - Sharing Band	Historical	No	No	No	No	No
	NorthWestern Corporation	Montana	Gas	Yes	Historical	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Yes	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Yes	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Yes	Historical	No	No	No	No	No
OGE Energy Corporation	Oklahoma Gas and Electric Co.	Arkansas	Electric	Yes	Historical	Partial	Yes	No	Yes	Yes
	Oklahoma Gas & Electric Co.	Oklahoma	Electric	Yes	Historical	Partial	No	No	Yes	Yes
Otter Tail Corporation	Otter Tail Power Co.	Minnesota	Electric	Yes	Fully Forecast	No	No	No	No	Yes
	Otter Tail Power Co.	North Dakota	Electric	Yes	Fully Forecast	No	No	No	No	Yes
	Otter Tail Power Co.	South Dakota	Electric	Yes	Historical	No	No	No	No	Yes

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
						Non-Volumetric Rate Design				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Electric fuel/gas commodity/purchase power	Test Year	Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design	Capital Cost Recovery
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Yes - Sharing Band	Fully Forecast	No	No	No	No	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Yes	Fully Forecast	No	Yes	No	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Yes	Fully Forecast	No	Yes	No	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	N/A	Fully Forecast	No	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Yes	Fully Forecast	Partial	No	No	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Yes	Fully Forecast	Partial	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Yes	Fully Forecast	Full	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Yes	Historical	Partial	No	No	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Yes	Historical	Partial	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Yes	Historical	Partial	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Yes	Fully Forecast	Partial	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Yes	Fully Forecast	No	No	No	No	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Yes	Historical	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Yes	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Yes	Fully Forecast	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Yes	Historical	Partial	No	No	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Yes	Historical	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Yes	Fully Forecast	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Yes	Fully Forecast	No	No	No	No	No

					Revenue Decoupling		Formula-based rates		SFV Rates Design		Non-Volumetric Rate Design		CCRM	
Proxy Group Average	Yes	64	Fully Forecast	31	Full	3	Yes	16	Yes	3	Yes	43	Yes	57
	No	0	Partially Forecast	7	Partial	32	No	61	No	74	No	34	No	20
	Yes - Sharing Band	7	Historical	39	No	42								
	N/A	6												
	Yes/N/A	90.91%	Fully/Partially Forecast	49.35%	RDM	45.45%	Yes	20.78%	Yes	3.90%	Yes	55.84%	CCRM	74.03%

MDU-MT [8]	Yes - Sharing Band	Historical	No	No	No	No	No

Notes:
[1] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] Regulatory Research Associates, effective as of September 30, 2022.
[3] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[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 July 18, 2022.
[6] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[7] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[8] Data provided by MDU.

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
		Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Average / 2	5
Alliant Energy Corporation	Iowa	Above Average / 3	3
	Wisconsin	Above Average / 2	2
Ameren Corporation	Illinois	Average / 2	5
	Missouri	Average / 3	6
American Electric Power Company, Inc.	Arkansas	Average / 1	4
	Indiana	Average / 1	4
	Kentucky	Average / 2	5
	Louisiana (PSC)	Average / 2	5
	Michigan	Above Average / 3	3
	Ohio	Average / 3	6
	Oklahoma	Average / 2	5
	Tennessee	Above Average / 3	3
	Texas (PUC)	Average / 3	6
	Virginia	Average / 1	4
	West Virginia	Below Average / 2	8
Duke Energy	Florida	Above Average / 2	2
	Indiana	Average / 1	4
	Kentucky	Average / 2	5
	North Carolina	Above Average / 3	3
	Ohio	Average / 3	6
	South Carolina	Average / 3	6
	Tennessee	Above Average / 3	3
Entergy	Arkansas	Average / 1	4
	Louisiana (NOCC)	Average / 3	6
	Louisiana (PSC)	Average / 2	5
	Mississippi	Above Average / 3	3
	Texas (PUC)	Average / 3	6
Evergy, Inc.	Kansas	Below Average / 1	7
	Missouri	Average / 3	6
IDACORP, Inc.	Idaho	Average / 2	5
	Oregon	Average / 2	5
NextEra Energy, Inc.	Florida	Above Average / 2	2
	Texas (PUC)	Average / 3	6
NorthWestern Corporation	Montana	Below Average / 1	7
	Nebraska	Average / 1	4
	South Dakota	Average / 2	5
OGE Energy Corporation	Arkansas	Average / 1	4
	Oklahoma	Average / 2	5
Otter Tail Corporation	Minnesota	Average / 2	5
	North Dakota	Average / 1	4
	South Dakota	Average / 2	5
Portland General Electric Company	Oregon	Average / 2	5
Southern Company	Alabama	Above Average / 1	1
	Georgia	Above Average / 2	2
	Illinois	Average / 2	5
	Mississippi	Above Average / 3	3
	Tennessee	Above Average / 3	3
	Virginia	Average / 1	4
Xcel Energy Inc.	Colorado	Average / 1	4
	Minnesota	Average / 2	5
	North Dakota	Average / 1	4
	New Mexico	Below Average / 2	8
	South Dakota	Average / 2	5
	Texas (PUC)	Average / 3	6
	Wisconsin	Above Average / 2	2
Proxy Group Average		Average / 1 - Average / 2	4.54
Montana-Dakota Utilities Co.	Montana	Below Average / 1	7

Notes
[1] Source: State Regulatory Evaluations, Regulatory Research Associates, as of October 15, 2022.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Highly Credit Supportive	2
Alliant Energy Corporation	Iowa	Most Credit Supportive	1
	Wisconsin	Most Credit Supportive	1
Ameren Corporation	Illinois	Very Credit Supportive	3
	Missouri	Very Credit Supportive	3
American Electric Power Company, Inc.	Arkansas	Highly Credit Supportive	2
	Indiana	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	Louisiana (PSC)	Highly Credit Supportive	2
	Michigan	Most Credit Supportive	1
	Ohio	Very Credit Supportive	3
	Oklahoma	Very Credit Supportive	3
	Tennessee	Highly Credit Supportive	2
	Texas (PUC)	Very Credit Supportive	3
	Virginia	Highly Credit Supportive	2
	West Virginia	Very Credit Supportive	3
Duke Energy	Florida	Most Credit Supportive	1
	Indiana	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	North Carolina	Most Credit Supportive	1
	Ohio	Very Credit Supportive	3
	South Carolina	More Credit Supportive	4
	Tennessee	Highly Credit Supportive	2
Entergy	Arkansas	Highly Credit Supportive	2
	Louisiana (NOCC)	Very Credit Supportive	3
	Louisiana (PSC)	Highly Credit Supportive	2
	Mississippi	Credit Supportive	5
	Texas (PUC)	Very Credit Supportive	3
Evergy, Inc.	Kansas	Highly Credit Supportive	2
	Missouri	Very Credit Supportive	3
IDACORP, Inc.	Idaho	Very Credit Supportive	3
	Oregon	Highly Credit Supportive	2
NextEra Energy, Inc.	Florida	Most Credit Supportive	1
	Texas (PUC)	Very Credit Supportive	3
NorthWestern Corporation	Montana	More Credit Supportive	4
	Nebraska	Very Credit Supportive	3
	South Dakota	Very Credit Supportive	3
OGE Energy Corporation	Arkansas	Highly Credit Supportive	2
	Oklahoma	Very Credit Supportive	3
Otter Tail Corporation	Minnesota	Highly Credit Supportive	2
	North Dakota	Highly Credit Supportive	2
	South Dakota	Very Credit Supportive	3
Portland General Electric Company	Oregon	Highly Credit Supportive	2
Southern Company	Alabama	Most Credit Supportive	1
	Georgia	Highly Credit Supportive	2
	Illinois	Very Credit Supportive	3
	Mississippi	Credit Supportive	5
	Tennessee	Highly Credit Supportive	2
	Virginia	Highly Credit Supportive	2
Xcel Energy Inc.	Colorado	Most Credit Supportive	1
	Minnesota	Highly Credit Supportive	2
	North Dakota	Highly Credit Supportive	2
	New Mexico	Credit Supportive	5
	South Dakota	Very Credit Supportive	3
	Texas (PUC)	Very Credit Supportive	3
	Wisconsin	Most Credit Supportive	1
Proxy Group Average		Very Credit Supportive - Highly Credit Supportive	2.38
Montana-Dakota Utilities Co.	Montana	More Credit Supportive	4

Notes
[1] Source: Views On North American Utility Regulatory Jurisdictions May Foreshadow Future Credit Trends--July 2022, Standard and Poor's Ratings Services, July 20, 2022.
[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

CAPITAL STRUCTURE ANALYSIS

Proxy Group Company	Ticker	Most Recent 8 Quarters (2020Q3 - 2022Q2) Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-term Debt Ratio	Total Capitalization
ALLETE, Inc.	ALE	56.61%	43.30%	0.00%	0.09%	100.00%
Alliant Energy Corporation	LNT	51.28%	46.32%	1.00%	1.40%	100.00%
Ameren Corporation	AEE	52.44%	45.65%	0.65%	1.26%	100.00%
American Electric Power Company, Inc.	AEP	47.33%	51.04%	0.00%	1.62%	100.00%
Duke Energy Corporation	DUK	52.37%	46.34%	0.00%	1.29%	100.00%
Entergy Corporation	ETR	46.21%	53.68%	0.10%	0.00%	100.00%
Evergy, Inc.	EVRG	58.04%	38.32%	0.00%	3.64%	100.00%
IDACORP, Inc.	IDA	54.05%	45.68%	0.28%	0.00%	100.00%
NextEra Energy, Inc.	NEE	59.86%	38.71%	0.00%	1.43%	100.00%
NorthWestern Corporation	NWE	47.36%	52.08%	0.00%	0.56%	100.00%
OGE Energy Corporation	OGE	52.70%	45.52%	0.00%	1.78%	100.00%
Otter Tail Corporation	OTTR	52.59%	44.82%	0.00%	2.59%	100.00%
Portland General Electric Company	POR	45.43%	52.88%	0.00%	1.68%	100.00%
Southern Company	SO	54.26%	44.76%	0.54%	0.44%	100.00%
Xcel Energy Inc.	XEL	53.85%	45.49%	0.00%	0.65%	100.00%
Average		52.29%	46.31%	0.17%	1.23%	
Median		52.59%	45.65%	0.00%	1.29%	
Maximum		59.86%	53.68%	1.00%	3.64%	
Minimum		45.43%	38.32%	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 have been excluded from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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" or "Company").

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 the Heskett Unit IV combustion turbine project ("Heskett IV Project") and to provide an update on the Heskett IV Project construction activities, schedule, and cost estimate. I will also describe, provide a schedule, and provide cost estimates for a water pipeline addition for Heskett III ("Water Pipeline"), a wind turbine repower project at Diamond Willow Wind Farm ("DW Repower Project"), and a light mitigation project at Thunder Spirit Wind Farm ("TS Light Mitigation Project").

<u>Heskett Unit IV and Water Pipeline Addition</u>

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 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 2684-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. What is a simple cycle combustion turbine?

A. SCCT’s are generally built to start up quickly to serve peak capacity needs. They usually supply a limited amount of energy because they are fueled by natural gas or liquid fuels which results in a higher fuel cost than with coal base load generation facilities. 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 also share use of R.M. Heskett Station III's turbine water wash system, balance of plant control system, instrument air system, and service building. 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 the Frame SCCTs as compared to other technologies.

Q. Please describe the schedule for the Combustion Turbine construction.

A. The general works construction ("GWC") was awarded on March 28, 2022 and site activities commenced on May 9, 2022. The civil/structural portion of the GWC activities include site preparation, foundations, concrete flatwork, and aboveground 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 February 2023. Commissioning and start-up activities will follow GWC substantial completion and are expected to take approximately three months.

Q. Please describe, and provide a schedule, for the Water Pipeline construction.

A. Due to the retirement of the coal units, Heskett Units I & II, and the associated water intake structure, a replacement water supply source was needed to provide water for fire protection and evaporative cooling of the combustion turbines. Montana-Dakota worked with consultants and the City of Mandan to develop a plan to bring water from the City of Mandan's water treatment facility to the combustion turbine site. The project involved 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 required 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 and the Certificate and Route Permit was issued May 4, 2022. Construction of the project commenced on May 9, 2022. The Water Pipeline is substantially complete and is in service. The permanent meter, measuring water consumption, has been ordered, but supply chain issues have delayed delivery. A temporary meter is currently in service, and the permanent meter will be placed in service upon arrival, completing this project.

Q. Please provide the current breakdown of the Heskett IV Project and Water Pipeline capital cost estimates.

A. The current Heskett IV Project capital cost is $15,570,254, as shown on Rule 38.5.123, Statement C, page 16. The Water Pipeline addition is $537,475 and is shown on Rule 38.5.123, Statement C, page 11 as FP-320773.

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 May 2023.

<u>Diamond Willow Repower Project</u>

Q. Please describe, and provide a schedule, for the DW Repower Project.

A. The DW Repower Project was initiated to perform extensive maintenance and upgrades on 13 wind turbines located near Baker, MT that comprise Diamond Willow Phase I. In-depth inspection on the blades of these 13 turbines resulted in the election to pursue blade refurbishment rather than blade replacement. Through blade refurbishment, the carbon footprint was able to be reduced by eliminating the need for blade disposal. Blade refurbishment consisted of damage repair, installation of Leading Edge Protection, upgrades to the Lightning Protection System, installation of Vortex Generators, and installation of Gurney Flaps. It is estimated that this refurbishment effort will increase capacity by 5%. The DW Repower Project also consisted of a controls upgrade and communications upgrade. Blade Bearings, Yaw Motors/Drives, Pitch Systems, and numerous other smaller components are included in the maintenance efforts of the DW Repower Project. Major maintenance and upgrades for the DW Repower Project began on July 17, 2022. The DW Repower Project was placed in service on October 31, 2022.

Q. Montana-Dakota has undertaken the repower project at Diamond Willow. Has the Company considered the impact to customers in its decision to repower Phase 1 Turbines?

A. Yes. Montana-Dakota prepared two financial models. The first model was based on the assumption that no repower would take place and the Company would continue to operate as it is today. The second model included the assumptions associated with the repower and included PTC's at 80% of the standard value. The repower project provided customers with an overall net benefit compared to continued operations. Since the modeling was complete, the Inflation Reduction Act of 2022 has since increased the PTC's to 100% of the standard value, which would further reduce the cost of the repower.

Q. Please provide the current breakdown of the DW Repower Project capital cost estimates.

A. The current DW Repower Project capital cost is $3,591,561 and is shown on Rule 38.5.123, Statement C, page 12 as FP-319115.

<u>Thunder Spirit Light Mitigation Project</u>

Q. Please describe, and provide a schedule, for the TS Light Mitigation Project.

A. The Thunder Spirit Wind Farm is subject to the North Dakota wind energy conversion facility lighting mitigation requirements set forth within NDCC §49-22-16.4 and the North Dakota Administrative Rules Chapter 69-06-11-02. A compliance extension through December 31, 2022, was granted by the Commission to explore the more cost-effective Light Intensity Dimming Solution ("LIDS") technology, as this technology was not approved by the Federal Aviation Administration ("FAA") at the time the rules were put in place. Montana-Dakota chose to pursue the Aircraft Detection Lighting System ("ADLS") option to comply with the extension timeline, as the LIDS technology has not been approved by the FAA.

The TS Light Mitigation Project requires the addition of a radar tower, emergency power, new wind tower lighting, and communication/power infrastructure upgrades. The project was placed in service on October 31, 2022.

Q. Please provide the current breakdown of the TS Light Mitigation Project capital cost estimates.

A. The current TS Light Mitigation Project capital cost is $375,177 and is shown on Rule 38.5.123, Statement C, page 12 as FP-319675.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2022.11

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 from 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 performing 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.

MAJOR CAPITAL PROJECTS

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.

Transmission Line Rebuild – Cedar Creek to Cabin Creek 60 kV Line

Q1. Please describe the Cedar Creek to Cabin Creek MT Line Rebuild project.

A. This project involves rebuilding a portion of the 60 kV transmission line between Glendive, MT and Baker, MT. The line section currently being rebuilt is between the Cedar Creek Substation and the Cabin Creek Substation. This line section is approximately 23 miles long. This is part of a larger multi-year project to rebuild the entire 60 kV line from Glendive to Baker, approximately 60 miles.

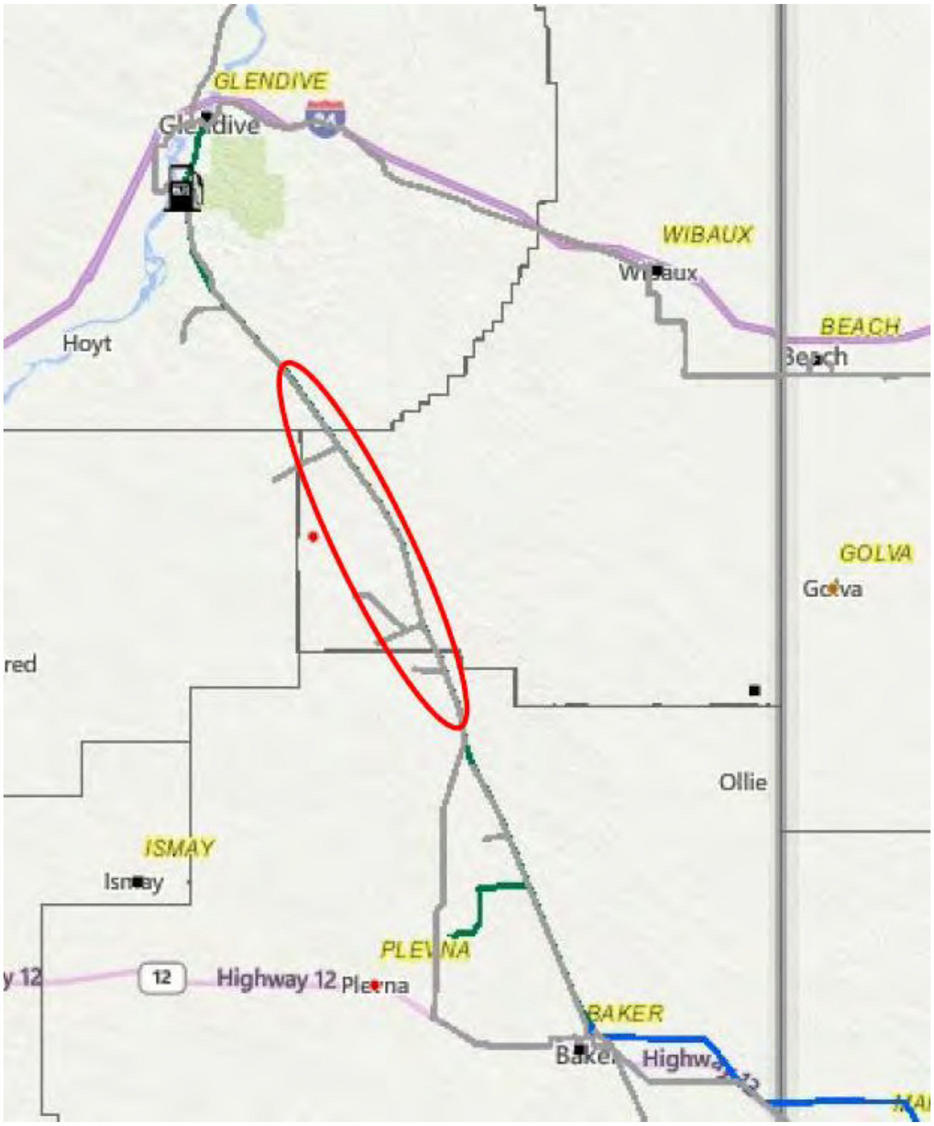


Figure 1 – Cedar Creek to Cabin Creek Line Route

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 1944.

Q3. What is the project timeline?

A. Project design was started in 2021 with construction starting the summer of 2022 and project completion in early 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. The original line was constructed using crossarms and no shield wire protecting from lightning strikes.

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 would result in ongoing increasingly frequent outages, higher overall replacement costs and higher operation and maintenance costs.

Q6. What are the costs of the project?

A. The costs to rebuild this section of transmission line is $4,209,910 and is shown on Rule 38.5.123, Statement C, page 12 as FP-319450.

<u>Transmission Line Construction – Miles City 115 kV Line</u>

Q1. Please describe the Miles City, MT Line project.

A. This project involves constructing a new 115 kV transmission line connecting the Western Area Power Administration (WAPA) Miles City 2 Substation to a new Montana-Dakota Miles City SW Transmission Substation on the west side of Miles City, MT. This transmission and substation project will serve the customers of Miles City and the surrounding communities of Kinsey, Hathaway, Rosebud, and Forsyth.

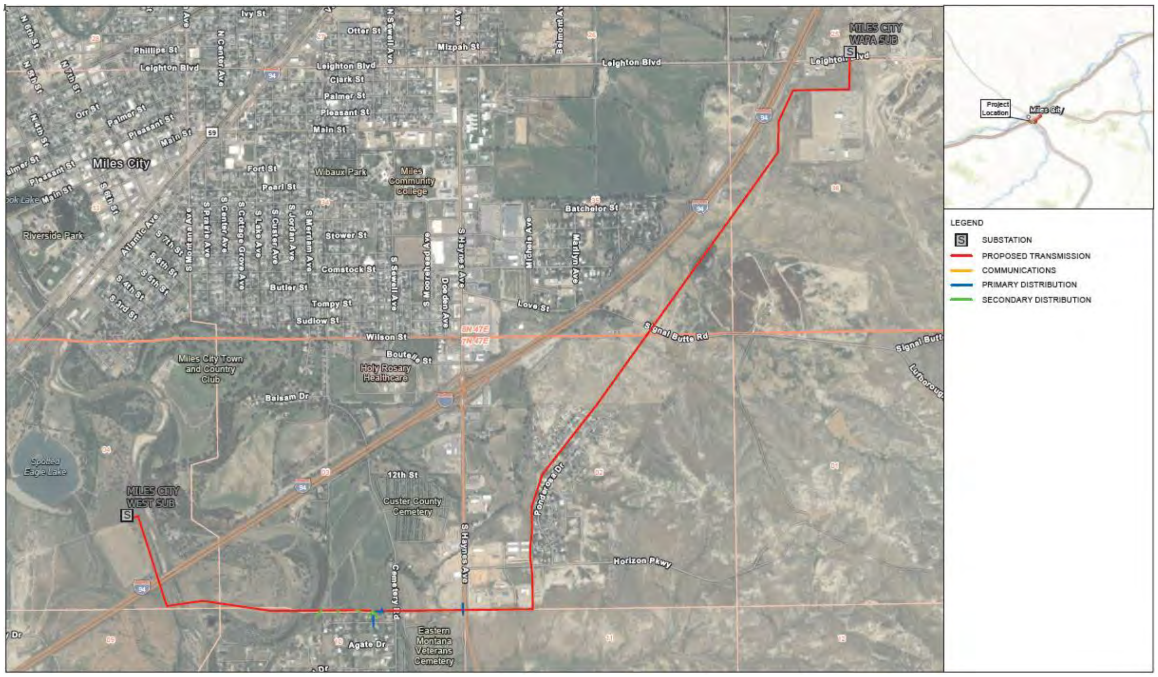


Figure 2 – Miles City 115 kV Line Route

Q2. Why did Montana-Dakota undertake this project?

A. Miles City electric customers are currently served by two power sources, a single 115 kV transmission line from WAPA and Montana-Dakota's Miles City gas combustion turbine. The load growth experienced in the Miles City area has exceeded the generation capacity of the Miles City Turbine, requiring another energy source in the area. The most economical solution was to develop a new 115 kV point of interconnection with WAPA and build a new 115 kV transmission line and substation.

Q3. What is the project timeline?

A. Project right-of-way work was started in 2018, engineering design began in 2020, construction began the spring of 2022, and the line was placed into service October 31, 2022.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota planning analysis identified an N-1 contingency that has the potential to cause significant impacts to the local electric system. By providing an additional energy source to the area greatly improves the reliability of the system, allows for additional load growth within the Miles City area, and provides operational flexibility for our electric operations departments.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The alternative to this transmission project would be to add generation with a second combustion turbine generator or to replace the existing generator at Miles City. Either of those options would be significantly more expensive that the current project.

Q6. What are the costs of the project?

A. The cost of the Miles City 115 kV transmission line is $1,772,511 and is shown on Rule 38.5.123, Statement C, page 12 as FP-316159.

<u>**Mandan, ND and Heskett Station Projects**</u>

Q1. Please describe the Mandan and Heskett projects.

A. Generation source changes at the Heskett Power Station in Mandan, ND has required modifications to the transmission system connecting those generators to the grid. Retirement of the Heskett Units I & II required relocating substation equipment from the Heskett switchyard to the Mandan Transmission Substation and the construction of a new Mandan 38th Street Transmission Substation. The Mandan Transmission Substation includes 230 kV bus work, two 230/115 kV power transformers, and 115 kV bus work. This connects the local 115 kV transmission system to the larger 230 kV bulk power system. The Mandan 38th Street Substation was constructed to interconnect Montana-Dakota's 115 kV transmission system to our 69 kV and 41.6 kV transmission systems in the area. This was previously located within the Heskett Power Station switchyard. Several transmission line relocations were required to accommodate the equipment relocations. The construction of the Heskett IV combustion turbine, which is fully explained by Mr. Geiger, required additional substation equipment and a new transmission line.

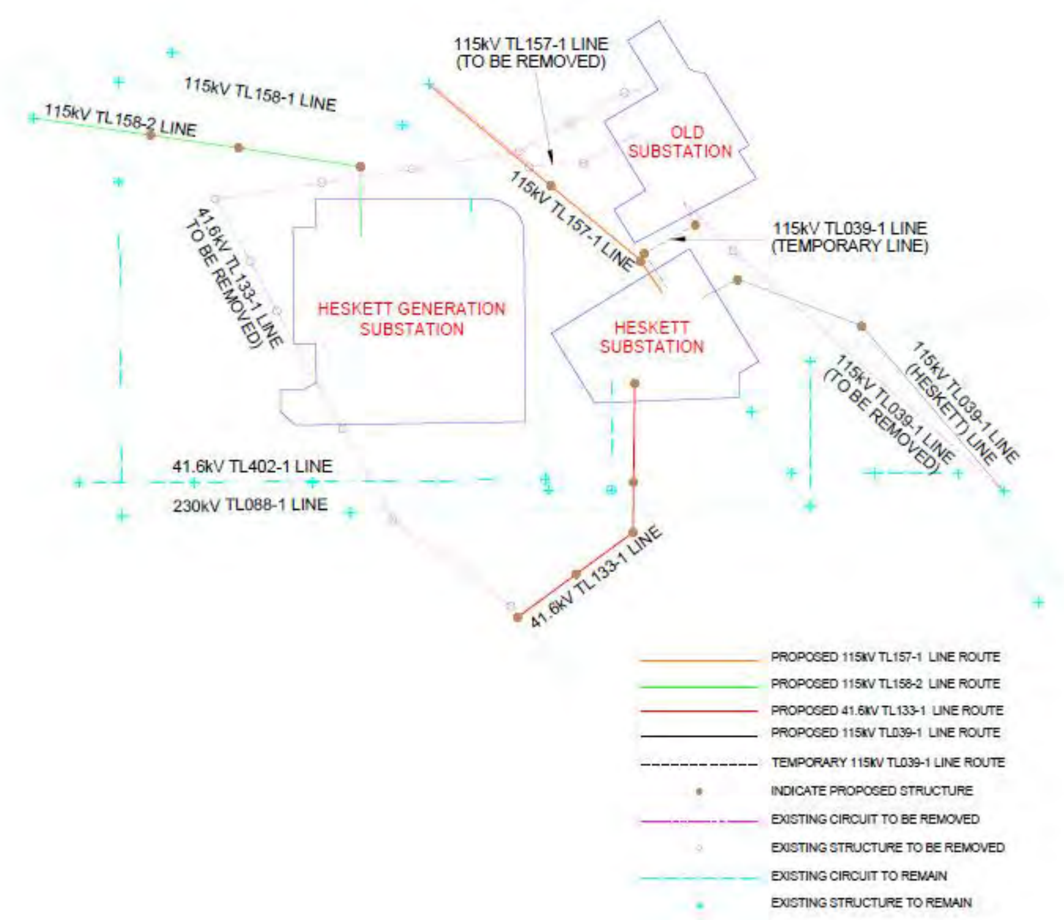


Figure 3 – Mandan Transmission Projects

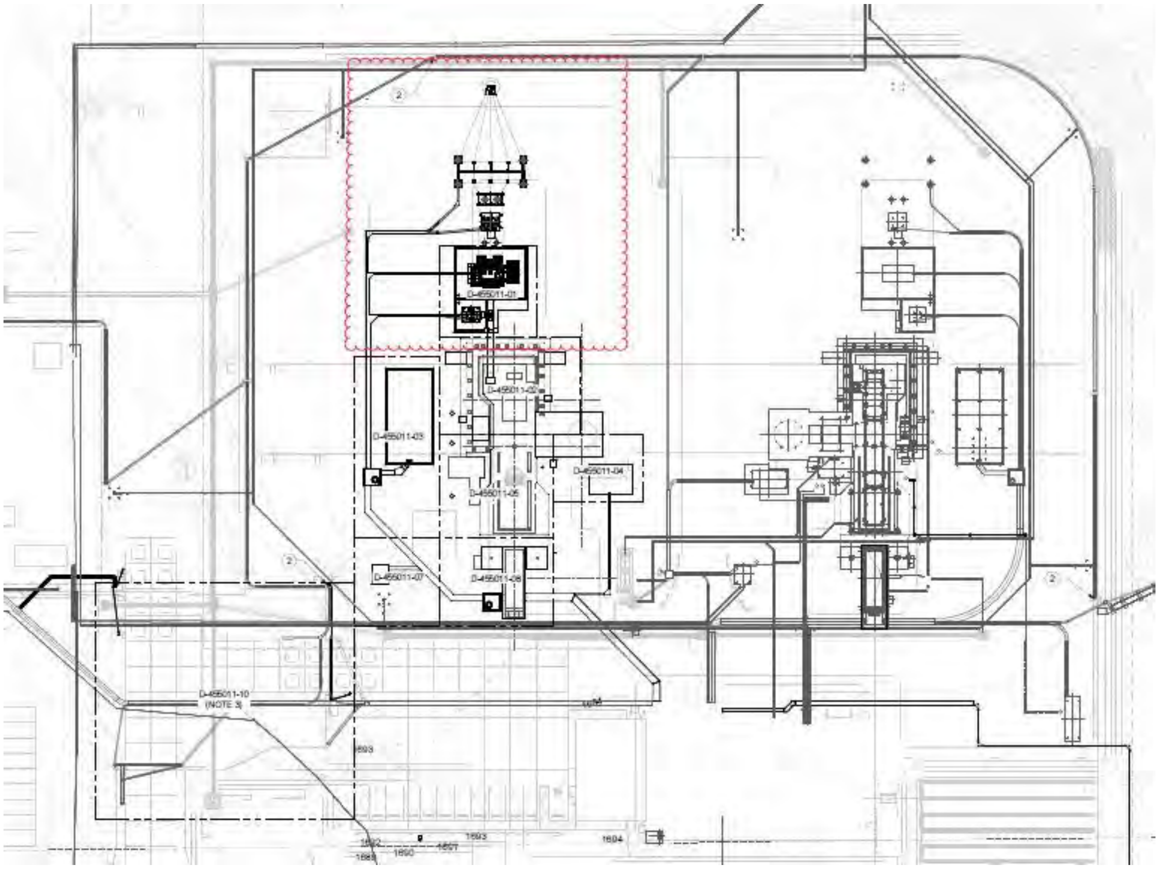


Figure 4 – Heskett IV Transmission Project

Q2. Why did Montana-Dakota undertake this project?

A. The retirement of the Heskett Power Station required establishment of new substation assets near the existing transmission system. This also allowed Montana-Dakota to improve the transmission system by replacing aging infrastructure. The addition of Heskett IV also requires additional transmission facilities to interconnect to the existing power grid.

Q3. What is the project timeline?

A. Project development and design was started in 2019 with the focus on substation construction and equipment relocations. Transmission line relocation construction began the summer of 2020 and has continued through the fall of 2022. The Mandan transmission project completion is expected November 15, 2022. The Heskett IV transmission and substation additions will be complete December 15, 2022.

Q4. How will the Montana-Dakota customers benefit from the project?

A. The Heskett generation and Mandan transmission system is part of Montana-Dakota's integrated transmission system, serving Montana, North Dakota, and South Dakota. Investment in the integrated transmission system provides benefits to customers in access to additional generation resources, grid reliability, and energy rates.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. The Company's decision related to generation assets, as further explained by Mr. Neigum, determined the need for this project. No substation and transmission alternatives were considered based on the existence of significant transmission investment already made in the Heskett and Mandan, ND areas.

Q6. What are the costs of the project?

A. The costs of the project is $718,903 and is shown on Rule 38.5.123, Statement C, page 12 as FP-322015, FP-319110, Various, FP-319131, and FP-322111.

<u>**Sidney, MT Shunt Capacitor Bank**</u>

Q1. Please describe the Sidney Capacitor Bank project.

A. This project involves constructing a new shunt capacitor bank on the 60 kV transmission system in the Sidney, MT area. Capacitor banks provide voltage support during certain operating conditions of the power grid.

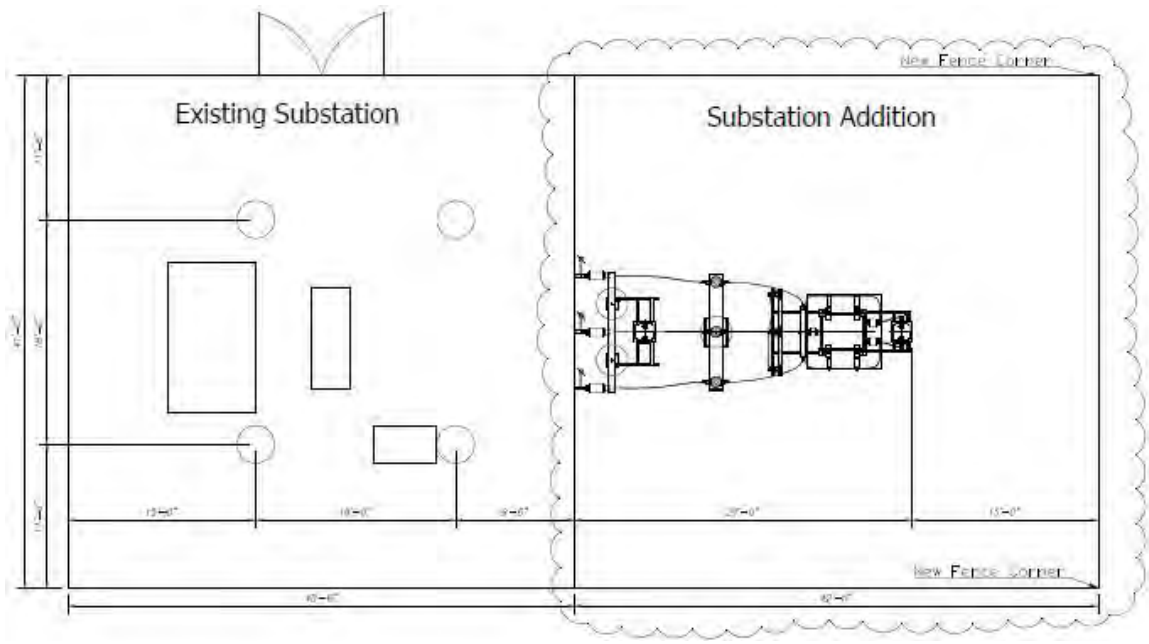


Figure 5 – Sidney Shunt Capacitor Bank Layout

Q2. Why did Montana-Dakota undertake this project?

A. Montana-Dakota transmission planning studies determined the exististance of low voltage conditions on the Sidney, MT transmission system during times when parts of the system are unavailable due to unplanned or planned outages. The capacitor bank provided additional voltage support to maintain acceptable voltages to serve the load in the area.

Q3. What is the project timeline?

A. The capacitor bank was designed, and equipment purchased in the summer of 2022. Construction of the facilities will occur in the spring of 2023.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Planning studies are routinely performed to identify power quality issues or load serving capability restrictions. Some operating situations will result in a strained system that could result in voltage collapse and significant 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. A typical alternative solution to the use of system reactive equipment is the construction of an additional transmission line from an alternate source. The construction of most transmission lines in this situation would be many times more expensive than the construction of this capacitor bank. Also the time required to construct transmission is also deterrent.

Q6. What are the costs of the project?

A. The costs to construct a shunt capacitor bank in Sidney is $624,823 and is shown on Rule 38.5.123, Statement C, page 12 as FP-322221.

<u>Glendive Substation Shop</u>

Q1. Please describe the Glendive Substation Shop project.

A. This project involves constructing a new shop and warehouse for the substation construction crews in Glendive, MT.

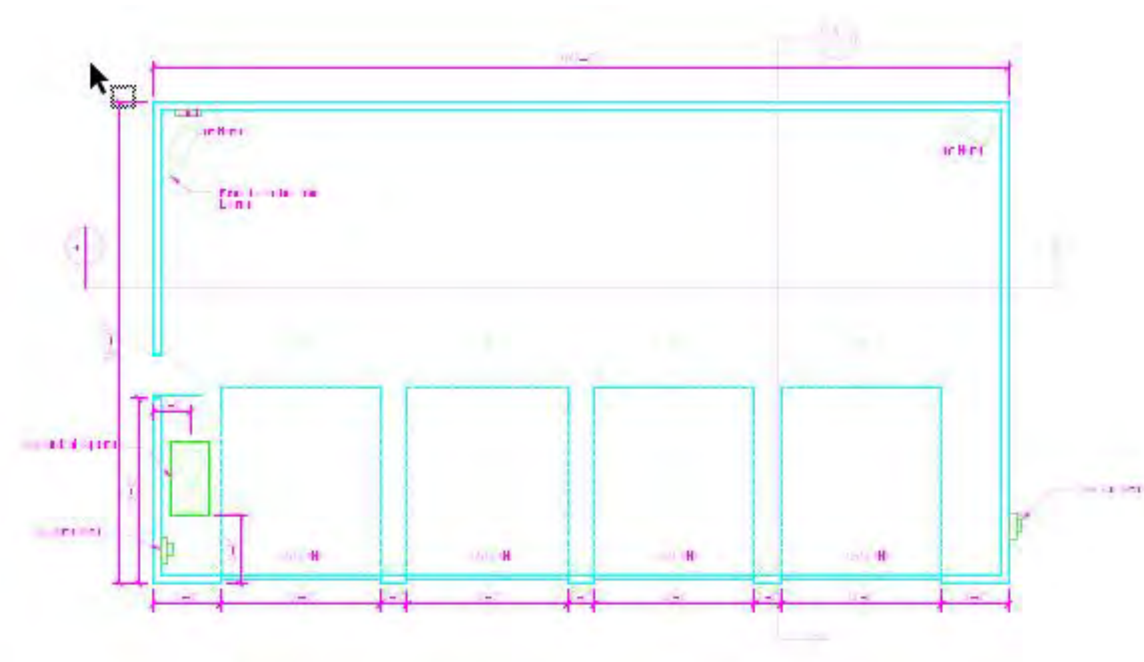


Figure 6 – Glendive Substation Shop Rendering

Figure 7 – Glendive Substation Shop

Q2. Why did Montana-Dakota undertake this project?

A. Growth within Montana-Dakota's district operations groups in Glendive resulted in a need for more space used by the substation crews. This new shop will allow all substation equipment and tools to share one location.

Q3. What is the project timeline?

A. The shop location is being constructed on company owned property. Construction of the shop facilities began in the spring of 2022 with project completion in December 2022.

Q4. How will the Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers require a high level of system reliability and Company response to outages and adverse transmission system conditions. Providing adequate facilities is paramount to providing customers with the best level of service possible.

Q5. Describe any alternatives considered to address the identified issues, if any, and associated costs compared to the chosen project.

A. No alternative was considered. Montana-Dakota substation construction crews require proper facilities to perform their work efficiently and safely.

Q6. What are the costs of the project?

A. The costs to construct a new Glendive Substation shop is $671,776 and is shown on Rule 38.5.123, Statement C, page 13 as FP-321685.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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 department. The system operations and planning department is responsible for electric resource planning and expansion studies for the Company.

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. My work experience includes four years as a nuclear plant engineer; three years of experience as a coal-fired power plant engineer; eleven years of generation development and operational responsibilities for coal-fired, gas-fired, and renewable generation sources; and fourteen years of experience 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 decision to construct the Heskett Unit IV simple cycle natural gas-fired combustion turbine (Heskett IV) as a generation resource for the Company's integrated electric system.

I will provide support for the Company's retirement analysis for Lewis & Clark Unit I and Heskett Unit I & II included in the Company's 2019 Integrated Resource Plan (2019 IRP).

I will provide support for a power purchase agreement (PPA) of capacity and energy.

Finally, I will provide support for the inclusion of Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) transmission charges and associated credits into the fuel and purchase power tracker.

Generation Planning

Q. How will Montana-Dakota utilize Heskett IV to meet customer needs?

A. Heskett IV is a least cost resource that will be used to meet customer peak demand requirements following the retirement of Lewis & Clark I, Heskett I, and Heskett II coal-fired generating stations.

Q. What were the plant closure dates for Lewis & Clark Unit I and Heskett Unit I & II?

A. Montana-Dakota announced on February 15, 2019, that it would be closing the Lewis & Clark I coal-fired station at the end of its coal supply agreement at the end of 2020; and the Heskett I & II coal-fired generation units at the end of their coal supply agreement at the end of 2021. These plant closure dates were supported in the Company's 2019 IRP filed with the Montana Public Service Commission on July 15, 2019. The actual end of coal operations date for Lewis & Clark I was March 31, 2021 and end of coal operations date for Heskett I & II were February 24, 2022 and January 22, 2022, respectively.

Q. What is the reason for the plant closures of Lewis & Clark I, Heskett I & II?

A. As shown in the 2019 IRP; these units were no longer economical to run as compared to other alternatives available to the Company and it was most cost beneficial to shut down the units at the end of their current coal supply agreements.

The costs of fuel, transportation, labor, and maintenance were rising at these facilities, as shown in the 2019 IRP[1], while the cost of natural gas and renewables in the area changed the dispatch characteristic of the plants so that in 2018 the units idled at their minimum output level between 80 and 90 percent of all online hours[2].

Q. How does Montana-Dakota offer its coal-fired generation into the MISO energy market?

A. Because of the Company's obligations under its coal-supply agreements, if the units are available to run, the generators are entered into the MISO market as a must run unit at their minimum output level and the units are dispatched economically above minimum load.

If the MISO market price is lower than the Company's marginal cost of fuel and variable operations & maintenance (O&M), these incremental

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[1] 2019 IRP, Volume IV, Attachment I, Pages 7 and 8.
[2] 2019 IRP, Volume IV, Attachment I, Page 4, Figure 2.

marginal costs are not recovered from the MISO market and are an additional cost to Montana-Dakota's customers over what the Company could have bought the same power from the market. The impact of this is demonstrated in the 2019 IRP[3].

Q. Does the IRP model tell the Company when to retire a generating unit?

A. The IRP model will not tell the Company when to retire but can be a tool to evaluate alternatives to help develop a least cost plan including the determination of a unit retirement date.

Q. What analysis did the Company perform to determine the customer benefits and least cost alternatives associated with the retirement of Lewis & Clark I and Heskett I & II?

A. As part of the 2019 IRP, the Company performed at least three separate analysis to help determine a best retirement date for Lewis & Clark I and Heskett I & II.

First, the Company varied the retirement dates of the units from 2029 to 2025 to 2021 in the 2019 IRP model. This analysis showed the earlier the retirement date, the greater the customer savings.

Second, the Company modeled retirement of the units in 2021 and

[3] 2019 IRP, Volume IV, Attachment I, page 5, Figure 3.

then allowed the 2019 IRP model to select each of the units for an additional 5-year life at the current O&M and fuel cost for the unit with no additional capital investment. None of these units were selected to run after 2021.

Finally, the Company developed a specific revenue requirement financial model to determine the actual projected customer impact associated with a retirement and replacement scenario. This analysis is described in 2019 IRP[4] and shows significant customer savings over the option of continuing to run the Lewis & Clark I and Heskett I & II units. This will be discussed further in the Direct Testimony of Mr. Jacobson.

Q. What resources did the Company evaluate the Heskett IV project against?

A. As part of the 2019 IRP, the Company developed an internal portfolio of future units including: coal, gas, wind, solar, and battery; and issued a Request for Proposals of Capacity and Energy Resources on August 1, 2018 (2018 RFP).

A copy of the 2018 RFP and summary of analysis of bids received is included in the 2019 IRP report[5].

Nineteen proposals from ten companies were received in response

[4] 2019 IRP, Volume IV, Attachment I, Figure 14, Page 17.
[5] 2019 IRP, Volume IV, Attachment F.

to the 2018 RFP. The majority of the proposals did not have signed generator interconnections agreements with MISO and therefore the magnitude of associated network upgrade costs associated with proposals were unknown at the time of the 2018 RFP and 2019 IRP analysis. No proposals were shortlisted from the 2019 RFP because of the uncertainty with potential network upgrade costs and the impacts to final pricing to the proposals. Most of the 2018 RFP proposals were included as future supply options in the 2019 IRP model to help guide the Company in potential additional resource selections when these proposals become more definitive.

Q. What did the results of the 2019 IRP reveal about the Company's least cost supply plan?

A. Heskett IV was selected as a least cost unit in the base case model run and all sensitivities which included: low/high load, low/high natural gas, low/high MISO energy, high combustion turbine costs, $30 per ton carbon cost, higher MISO capacity requirement, and a high natural gas / MISO energy model run. The higher MISO capacity requirement model run used a 90 percent coincident factor versus the 81.5 percent coincident factor used in the base case. The high natural gas/MISO energy model run used a 2022 natural gas price of $7.57 per dk and a 2022 MISO energy price of $50.97 and $47.62 per MWh for the on-peak and off-peak hours, respectively.

Q. What other resources did the 2019 IRP model select as a least cost plan?

A. In addition to the Heskett IV unit, the model also selected future wind, solar, storage, and natural gas-fired combined cycle as part of the Company's least cost plan[6].

Q. Why didn't the Company enter into contract negotiations with the wind and solar resources identified in 2022 and 2023?

A. These units did not have a final interconnection agreement and the costs for their network upgrades was still unknown. Based upon potential network upgrade costs for other projects coming out of MISO's generator interconnection queue, a cost adder of up to $25 per MWh could be added to these projects. The Company issued another RFP prior to its next IRP to see if any of these projects or others had final interconnection costs and better price certainty.

These projects were selected in addition to Heskett IV, which is a least cost resource in all modeling scenarios.

[6] 2019 IRP, Volume IV, Attachment C, Page 14, Table 3-1.

Q. What are the impacts of replacing baseload coal with a natural gas-fired peaking turbine?

A. The 2019 IRP model selected the peaking turbine for capacity requirements and the Company will rely on the MISO market for additional energy purchases.

The 2018 economic comparison in the 2019 IRP showed that fuel and variable O&M costs of Lewis & Clark I and Heskett I & II were projected to be $9.75 per MWh to $29.62 per MWh over the MISO market energy purchases[7].

Market prices would have had to rise significantly for Lewis & Clark I and Heskett I & II to be economically competitive again. By constructing Heskett IV at its current site, the Company has created an opportunity to combine cycle Heskett III and Heskett IV, and/or add additional renewable generation if market energy prices rise significantly in the future.

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[7] 2019 IRP, Volume IV, Attachment I, Page 12, Figure 11.

Purchase Power Agreement (PPA)

Q. How will the Company meet the capacity need of its customers between the retirement of Lewis & Clark I and Heskett I & II?

A. The Company entered into two PPAs to purchase capacity and energy between the time period of the retirement of Lewis & Clark I and Heskett I & II, and the completion of Heskett IV. The Company also purchased additional capacity and energy to cover forecasted capacity deficits through May 31, 2026. The quantities of capacity and energy in the PPAs are:

Year	Capacity (MWs)	Energy (MWh)
2021-2022	75	30
2022-2023	90	75
2023-2024	30	75
2024-2025	30	75
2025-2026	30	75

The pricing in the PPAs is below the modeled MISO Energy Market price forecast in the 2019 IRP, below the RFP responses to the 2018 RFP, below the separate financial analysis price assumptions in Volume IV, Attachment I in the 2019 IRP, and below the current MISO market prices.

Q. Is the addition of Heskett IV the best alternative for the Company?

A. Yes, the addition of Heskett IV; coupled with the retirement of Lewis & Clark I and Heskett I & II; provides significant customer savings versus continuing to run these coal units or implementing another future supply plan. The Heskett IV addition was a least cost resource in the 2019 IRP base case and all sensitivities.

<u>Transmission Service Charge Recovery</u>

Q. How are MISO and SPP transmission service charges recovered?

A. The MISO and SPP transmission service charges applicable to Montana customers are recovered in base rates today.

Q. How are the MISO and SPP energy market charges recovered?

A. The MISO and SPP energy market charges in Montana are currently recovered through the Rate 58 Fuel and Purchased Power Cost Tracking Adjustment.

Q. What SPP energy market charges are recovered under Rate 58?

A. Montana-Dakota is required to be an SPP Market Participant associated with the network integrated transmission system (NITS) service that it takes from SPP. The transmission flows to Montana-Dakota's load and from Montana-Dakota's generation in areas taking SPP NITS, and are charged SPP market marginal losses and congestion.

These SPP marginal losses and congestion are refunded today under Rate 58.

Q. What is the magnitude of the SPP market energy refunds today under Rate 58?

A. Through September 2022, there has been a refund of $8,152,181 for SPP market energy charges to all Montana-Dakota customers; Montana's share being $2,007,334 and refunded to Rate 58; for marginal losses, congestion, and auction revenue rights (ARRs) assigned to Montana-Dakota. In 2021 and 2020, these refunds totaled $11,196,756 and $2,118,871; with Montana's refunded share being $2,788,231 and $526,378, respectively.

Q. Why is there a net refund associated with SPP marginal losses, congestion and ARRs?

A. The marginal losses and congestion refunds are a function of Montana-Dakota's nodal SPP price as compared to the MISO-SPP Seam interface price multiplied by the amount of energy flowing to Montana-Dakota's load and from Montana-Dakota's generators that use the SPP transmission service. In addition, Montana-Dakota also receives revenues for ARRs that SPP sells for Montana-Dakota. Today ARRs flow through Rate 58.

Q. What is the level of revenues that Montana-Dakota is expecting to receive from MISO for ARRs?

A. Montana-Dakota forecasts that it will receive $18 million in MISO ARR's for the 2022-2023 MISO planning year. Montana's share of the MISO ARR's revenues is estimated to be $4.5 million and will be refunded under Rate 58.

Q. What change are you requesting regarding the recovery mechanism of MISO and SPP transmission service charges?

A. Montana-Dakota believes it would be more appropriate in Montana to recover MISO and SPP transmission service costs and any associated revenue credits associated with these charges under Rate 58 versus continued recovery in base rates.

Q. Why do you believe the change in recovery of transmission service to Rate 58 is more appropriate?

A. The MISO and SPP energy market and transmission systems continue to become more interconnected and the costs and benefits of each are more mutually dependent of each other than in the past.

SPP and MISO transmission service charges are producing a significant market benefit for Montana-Dakota's customers associated with the transmission service that it takes. However, the SPP and MISO transmission charges are recovered in base rates and the market revenues produced by the transmission service are credited to Rate 58 creating a mismatch today. Both should be charged and credited to Rate 58 going forward so that the market benefit and the transmission charge that created it, can be offset against each other.

Q. What do you mean by the market and transmission systems being more mutually dependent?

A. The low energy costs that Montana-Dakota’s customers benefit from the MISO energy market are directly associated to the transmission service that MISO provides to its members.

In MISO and SPP, customer load is assigned the transmission service charges. Generators are not assigned charges for transmission service. These transmission service charges are directly tied to customer load and are billed based on MW demand or MWh energy billing determinants. Charges associated with transmission service vary with the amount of service (MW or MWh) taken and the qualifying transmission investments recovered in rates. The transmission charges paid by Montana-Dakota under MISO Schedules 26 and 26a and SPP Schedules 9 and 11 are for investments owned by others and recovered under the MISO and SPP transmission tariff and associated schedules.

Q. Can you elaborate more on MISO Schedules 26 and 26a charges?

A. MISO developed the Multi-Value Project (MVP) classification and cost recovery mechanism under Schedule 26a to provide the ability to develop additional renewable energy resources and reduced market congestion which shows up as reduced market energy prices to the benefit of customers. However, the payment for these MVP projects is billed through a MISO Schedule 26a transmission service charge.

Rather than recovering MISO Schedule 26a transmission service charges through base rates, as they are today, these costs would more appropriately be recovered under Rate 58 in Montana where the benefits are received by the customers in the form of lower energy prices.

MISO Schedule 26 projects are cost shared reliability projects or projects which qualify for cost sharing under a MISO postage stamp rate. A portion of the MISO Schedule 26 charges that Montana-Dakota pays includes the Minnesota CAPEX 2020 projects. These costs vary over time as their annual revenue requirement is updated. MISO Schedule 26 also includes the cost allocation of Market Efficiency Projects (MEPs).

Q. What are Market Efficiency Projects (MEPs)?

A. MEPs are a class of projects, defined to reduce market congestion cost, and recovered by benefiting load through direct allocation or through a system postage stamp which are both recovered through MISO Schedule 26 charges. These projects benefit load through reduced market energy prices. Today costs associated with MEPs are recovered in base rates but would be more appropriate to recover under Rate 58 going forward.

Q. Is MISO working on any future planning transmission initiatives?

A. MISO's Long Range Transmission Plan (LRTP) study is looking at impacts to the MISO transmission system, under various futures, to develop a list of projects needed to better meet the transmission system of the future as many states and utilities in the MISO footprint are looking to replace baseload and fully dispatchable resources with more intermittent sources of generation. The first round of LRTP studies produced a portfolio of projects worth $10.3 billion which will use the MVP cost allocation on a subregional basis what was approved by the MISO Board of Directors in July of 2022[8].

The purpose of these LRTP transmission studies is to maintain system reliability while efficiently moving large amounts of energy across the MISO footprint as additional renewables and distributed energy resources are developed. This approach to MISO LRTP transmission planning and recovery of energy delivery investments will continue to support the inclusion of MISO transmission service charges under Rate 58.

Q. Can you elaborate more on SPP Schedule 9 and 11 charges?

A. SPP Schedule 9 is for Network Integrated Transmission Service (NITS) charges which Montana-Dakota began taking from SPP on

[8] MISO Energy Website. MISO Long Range Transmission Planning – Reliability Imperative. https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning/

October 1, 2015 when Western Area Power Administration and Basin Electric joined SPP as a transmission owning member.

SPP Schedule 11 goes along with NITS service as is a recovery of SPP Highway Byway cost allocated projects which are subregionally and regionally allocated to applicable load.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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, Montana, and North Dakota 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 new costs involved to operate an Outage Management System at Montana-Dakota.

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. 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.

Q. Will the OMS deployment require additional staff?

A. 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:

- <u>System Support Engineer</u>: An Operations Technology (OT) position is required to support the software, hardware, and communications within the SCADA/DMS/OMS systems.
- <u>System Administrator</u>: An Information Technology (IT) position is required to support the security, user administration, and maintenance of the SCADA/DMS/OMS systems.
- <u>System Operators</u>: 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.

- <u>Business Analyst</u>: This position will manage the daily operation of the OMS system, including daily outage reviews, Quality Assurance/Quality Control, data analysis, and reporting.
- <u>Promotions</u>: The expanded responsibilities of a central OMS deployment and staffing will require supervisory promotions within existing departments.

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 Montana 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.

Q. 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 within the test period ending 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.

Q2. What are the costs of the project?

A. The capital cost of the Outage Management System allocated to the Montana Electric jurisdiction is $656,815 and is shown in Rule 38.5.123, Statement C, page 14 as FP-316300. The O&M costs related to the additional positions needed for the OMS are $167,497. This is comprised of $123,986 of labor found on Rule, 38.5.157, Statement G, page 6, $14,444 of incentives found on Rule 38.5.157, Statement G, page

5 and benefit increases of $29,037 found in Workpaper Statement G, page 14.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE PUBLIC SERVICE COMMISSION OF MONTANA

DOCKET NO. 2022.11.___

PREPARED DIRECT TESTIMONY OF

LARRY E. KENNEDY

Q1. Please state your name and business address.

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?

I am employed by Concentric Advisors, ULC.

Q3. What is your position with Concentric Advisors, ULC ("Concentric")?

I am employed by Concentric as a Senior Vice President.

Q4. On whose behalf are you submitting this Direct Testimony?

I am submitting this Direct Testimony before the Montana Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q5. Please describe your education and experience.

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-1).

Q6. Please describe Concentrics's activities in energy and utility engagements.

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?

Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No.___(LEK-1).

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q8. What is the purpose of your Direct Testimony?

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-2), 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. Exhibit No.___(LEK-3) presents the depreciation tables which have been revised to reflect the Diamond Willow Wind Farm repower project.

Q9. Please provide a brief overview of the analyses that led to your depreciation recommendations.

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?

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, and a description of changes in the depreciation methods used in this study as compared to prior depreciation studies completed by prior consultants on behalf of MDU. Section IV provides concluding comments.

<u>II - SCOPE OF THE DEPRECIATION STUDY</u>

Q11. Please outline the Scope of the Depreciation Study.

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.

The depreciation study report is presented in nine (9) Sections 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	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 2, 3, 4, 5, and 6.
Section 6	Presents Retirement Rate Analysis
Section 7	Presents Net Salvage Calculations
Section 8	Presents 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?

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 calculations 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.

The study results in an annual depreciation expense accrual related to the recovery of original cost (i.e. excluding net salvage requirement) of $57.8 million, when applied to depreciable plant balances, as of December 31, 2020, and accounting for the Diamond Willow Wind Farm repower project 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*	552,138,101	4.05%	22,374,578
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*	1,941,233,414	2.98%	57,828,801

*Includes additional investment in 2022 related to the Diamond Willow Wind Farm repower project.

Q15. How do the above depreciation rates compare to the previously proposed depreciation rates?

The following chart summarizes the proposed composite depreciation rates as compared to the previously proposed composite depreciation rates from the 2018 depreciation study.

Plant Group	**Currently Proposed Depreciation Rate**	**Previously Proposed Depreciation Rate**
Steam Plant	2.45%	4.02%
Other Production Plant*	4.05%	3.72%
Transmission Plant	1.70%	1.54%
Distribution Plant	3.25%	3.03%
General Plant	7.34%	6.75%
Total Plant in Service*	2.98%	3.34%

***Includes additional investment in 2022 related to the Diamond Willow Wind Farm repower project.**

Q16. Please describe the reasons for the large decrease in the depreciation rates related to electric production plant.

The combined weighted average depreciation rate proposed for production is 3.41% as compared to an average depreciation rate for production assets of 3.89% as recommended in the last depreciation study representing a 12.34% decrease in the combined depreciation rate. The largest influence in this decline is the retirement of the Heskett and Lewis & Clark steam generating units, which has removed the shortest remaining life assets from the depreciation rate calculations.

The depreciation study has continued the incorporation of a Life Span approach for the production assets, which has been incorporated into the depreciation rate calculations for the past two depreciation studies. 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 3.7 of my depreciation study report. The probable retirement dates for each of the generation plants was provided by MDU to me 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	Currently Proposed	Previously Proposed
Heskett Generating Stations (Common Plant)	N/A	2025
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	2028
Glendive Turbine – Unit 2	2046	2046
Miles City Turbine	2033	2028
Portable Generators	2047	2047
Heskett Turbine	2057	2057
Diamond Willow Wind Farm	2035	2035
Cedar Hills Wind Farm	2035	2035
Lewis & Clark Turbine - RICE	2045	2045
Ormat Generation Facility	2034	2029
Thunder Spirit Wind Farm I	2040	2040
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 unit at Lewis and Clark Generating Station has 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, 2028 to December 31, 2033, the Miles City Turbine has been extended from December 31, 2028 to December 31, 2033, and the Ormat Generation Facility has been extended from December 31, 2029 to December 31, 2034. Additionally, a new life span date has been introduced for Thunder Spirit Wind Farm II units. With these life span extensions there has been a reduction in the depreciation expenses required at a number of plants.

Diamond Willow Wind Farm is going through a repower of its assets and is expected to be complete and online during Q4 2022. The repower includes new investment of approximately $14.4million. However, as this study was calculated as of December 31, 2020 for depreciation rates to be effective in 2023 in Montana, the depreciation study included the calculation of the appropriate depreciation rates for the Diamond Willow facility inclusive of the $14.4 million of repower expenditures in 2022. The calculations for Diamond Willow are based on the 55-R3 average service life, which aligns with the other wind farms in the system, and a 2035 life span date as provided by MDU. These parameters remain consistent with the previous study.

Over the period since the 2018 depreciation study, the gross depreciable cost related to thermal steam generation plants that incorporate the use of a life span has decreased by approximately $180 million (a decrease of approximately 32%). This decrease has been offset by a $79.5 million increase in the gross plant investment in Other Productions accounts (an increase of 17%). This additional investment has been made in the gas turbine and renewable energy generation, representing an increase in these Other Production accounts of 17% since December 31, 2017.

Q17. Please outline the reasons for the increase in the composite depreciation rate for electric transmission plant.

Within the electric transmission group of assets, the most significant cause of the increase in depreciation rates is the significant increase in gross plant in service over the period since December 31, 2017. Over this period of time since the last depreciation study, the investment in the transmission has increased by $227 million (an increase of 77%). The average service life estimates within the transmission system have not significantly changed in this current study, with a small increase in the average service life estimate for Account 355.00 Poles and Fixtures, and small changes in the retirement dispersion curve (Iowa curve) estimate in accounts 355.00 and 356.00 as seen in the chart below.

Account	**Description**	**Proposed Iowa Curves**	**Current Iowa Curves**
350.20	Land Rights	70-R4	70-R4
352.00	Structures and Improvements	50-R2	50-R2
353.00	Station Equipment	65-R2.5	65-R2.5
354.00	Towers and Fixtures	60-R4	60-R4
355.00	Poles and Fixtures	63-R2.5	60-R3
356.00	Overhead Conductors and Devices	70-R3	70-R4
357.00	Underground Conduit	50-R3	50-R3
358.00	Underground Conductors and Devices	50-R3	50-R3

In addition to the small changes in the average service life and retirement dispersion estimates as noted above, my depreciation study report also recommends a small increase in the estimated cost of removal in Account 355.00 – Poles and Fixtures from negative 30 percent to negative 35 percent. However, the larger influence in the increase in the transmission system composite depreciation rate is the change in relative weighting of investment by account. The December 31, 2020 investment is more weighted to the shorter life accounts because of the larger percentage of new investment being capitalized to shorter life accounts as compared to the weighting as of December 31, 2017. This change in the weighting of the asset composition by account, combined with a small increase in the estimated cost of removal in Account 355.00 – Poles and Fixtures from negative 30 percent to negative 35 percent has resulted in an increase in the composite depreciation rate calculations that has been partially offset by the changes in the average service life and retirement dispersion estimates. The specific reasons for the selection of the average service life and net salvage estimate are discussed in Section 3.6 of my report for each of the large transmission accounts. Additionally, the results of the statistical mortality study are presented for each account in Section 6 of my report.

Q18. Please outline the reasons for the increased composite depreciation rate for the electric distribution assets.

The depreciation study has resulted in recommendations to extend the average service life estimates in 3 accounts and to shorten the average service life in two accounts. 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 extensions.

The average service life and net salvage percentages for the distribution accounts as recommended in my study as compared to the previously proposed percentages are summarized below:

Account	Description	Average Service Life		Net Salvage	
		Proposed	**Current**	**Proposed**	**Current**
360.20	Rights of Ways	62-R3	62-R3	0	0
362.00	Station Equipment	53-R2	53-R2.5	(15)	(10)
364.00	Poles, Towers & Fixtures	60-R1.5	60-R1.5	(120)	(120)
365.00	Overhead Conductor & Devices	65-R2	62-R1.5	(110)	(100)
366.00	Underground Conduit	50-R3	50-R3	0	0
367.00	Underground Conductor & Devices	42-R2.5	40-R2	(50)	(40)
368.00	Line Transformers	55-R3	55-R3	(20)	(20)
369.10	Services	50-R3	45-R2	(50)	(50)
370.00	Meters	20-L3	20-L3	(5)	(5)
371.00	Installation on Customers Premises	20-R0.5	23-R0.5	(15)	(15)
373.00	Street Lighting System	43-R1	48-R1	(45)	(50)

The detailed analysis of the average service life and net salvage estimates is provided in Section 6 of my MDU report.

Q19. Is the trend for more negative net salvage percentage as noted above typical for electric distribution assets?

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 5 years. Accordingly, it has become the most debated topic of depreciation studies and depreciation conferences. At the 2018 Society of Depreciation Professionals (SDP) conference held in September of 2018, there were 4 presentations regarding the large increase in cost of removal expenditures. This trend has been witnessed over virtually all electric, gas and pipeline utilities. As such the trend witnessed in my MDU study is consistent with depreciation studies conducted across North America.

Q20. What is causing this trend to increased cost of removal of utility assets?

It is generally accepted that there exist 3 main causes of these increases. Firstly, as the average age of utility assets continue to be extended, the impacts of inflation becomes more pronounced. For example, over the past three depreciation studies, the MDU Account 364 – Poles Towers and Fixtures the average service life has been extended from 38 years to 60 years. As such, over the course three 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 percent 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 over the time 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 must 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 have 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 assts, 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

Q21. How is depreciation defined for a rate regulated utility?

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 utilities 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 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

[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**

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.

Q22. Please outline the depreciation methods and procedures used in your depreciation study.

The calculation of annual and accrued depreciation, based on the Straight-Line Method, requires the estimation of survivor 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 ALG 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.

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.

IV – CONCLUDING REMARKS

Q23. What is your conclusion with respect to Montana-Dakota's proposed depreciation expense?

My conclusion is that Montana-Dakota's requested depreciation rates resulting in a composite depreciation rate of 2.98 percent is 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.

Q24. Does this conclude your Direct Testimony?

Yes, it does.

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the

Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).

- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)

- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.

- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.

- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	pending Montana-Dakota Utilities
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	pending

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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
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

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243

Montana-Dakota Utilities Co. - Electric Division

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - TOTAL

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
STEAM PLANT									
311.00	Structures and Improvements	68-R3	0	81,113,617.27	37,840,342	43,273,275	1,599,729 *	1.97	- *
312.00	Boiler Plant Equipment	50-R1	0	198,020,003.63	78,534,155	119,485,849	5,252,395 *	2.65	- *
314.00	Turbogenerator Units	50-R0.5	0	63,076,279.95	24,326,382	38,749,898	1,490,694 *	2.36	- *
315.00	Accessory Electric Equipment	50-R2.5	0	20,863,863.43	9,795,524	11,068,339	479,222 *	2.30	- *
316.00	Miscellaneous Power Plant Equipment	30-R0.5	0	9,397,126.74	3,479,990	5,917,137	293,657 *	3.12	- *
TOTAL STEAM PRODUCTION PLANT				372,470,891.02	153,976,393	218,494,498	9,115,697		
OTHER PRODUCTION PLANT									
341.10	Structures and Improvements	70-R1	0	16,578,181.79	2,071,956	14,506,226	536,307 *	3.24	*
341.20	Structures and Improvements - Wind Farm	70-R1	0	42,546,921.10	5,675,437	36,871,484	1,981,332 *	4.66	*
341.51	Portable Generators	70-R1	0	169,459.16	42,894	126,565	5,132 *	3.03	- *
341.71	Ormat Generation Facility	70-R1	0	701,334.45	400,365	300,969	23,084 *	3.29	- *
342.00	Fuel Holders, Producers and Accessories	40-R4	0	5,640,437.75	1,239,809	4,400,629	181,339 *	3.21	- *
344.10	Generators	55-R3	0	103,677,534.12	32,876,006	70,801,528	2,811,895 *	2.71	- *
344.20	Generators - Wind Farm	55-R3	0	308,667,927.63	79,682,252	228,985,676	12,530,346 *	4.06	- *
345.10	Accessory Electric Equipment	25-L2	0	17,864,490.28	2,191,254	15,673,236	970,133 *	5.43	- *
345.20	Accessory Electric Equipment - Wind Farm	25-L2	0	51,401,813.40	5,433,845	45,967,968	3,124,300 *	6.08	- *
346.10	Miscellaneous Power Plant Equipment	28-S1	0	4,229,486.14	623,813	3,605,673	176,522 *	4.17	- *
346.20	Miscellaneous Power Plant Equipment - Wind Far	28-S1	0	660,514.98	127,731	532,784	34,188 *	5.18	- *
TOTAL OTHER PRODUCTION PLANT				552,138,100.80	130,365,362	421,772,738	22,374,578		
TRANSMISSION PLANT									
350.20	Land Rights	70-R4	0	15,602,605.19	2,382,259	13,220,346	201,419	1.29	62.8
352.00	Structures and Improvements	50-R2	0	329,102.63	10,103	318,999	6,598	2.00	48.4
353.00	Station Equipment	65-R2.5	(10)	222,333,780.46	58,172,868	186,394,290	3,269,741	1.47	54.2
354.00	Towers and Fixtures	60-R4	(20)	4,992,886.11	3,541,545	2,449,919	95,046	1.90	25.6
355.00	Poles and Fixtures	63-R2.5	(35)	172,142,521.86	31,612,348	200,780,056	3,546,427	2.06	55.7
356.00	Overhead Conductors and Devices	70-R3	(20)	101,836,280.32	21,606,428	100,597,108	1,670,180	1.64	59.1
357.00	Underground Conduit	50-R3	0	1,944,583.16	472,994	1,471,589	38,761	1.99	38.0
358.00	Underground Conductors and Devices	50-R3	0	3,101,857.38	759,136	2,342,721	61,718	1.99	38.0
TOTAL TRANSMISSION PLANT				522,283,617.11	118,557,683	507,575,028	8,889,889		
DISTRIBUTION PLANT									
360.20	Rights of Way	62-R3	0	961,139.62	663,409	297,731	7,959	0.83	32.5
362.00	Station Equipment	53-R2	(15)	89,780,857.62	23,531,314	79,716,673	1,841,200	2.05	42.3
364.00	Poles, Towers & Fixtures	60-R1.5	(120)	46,982,854.51	23,781,444	79,580,836	1,765,540	3.76	45.4
365.00	Overhead Conductor & Devices	65-R2	(110)	36,578,399.40	20,024,517	56,790,122	1,125,010	3.08	49.8
366.00	Underground Conduit	50-R3	0	235,918.03	126,875	109,043	3,609	1.53	26.5
367.00	Underground Conductor & Devices	42-R2.5	(50)	133,794,645.52	31,950,405	168,741,563	5,448,624	4.07	32.3
368.00	Line Transformers	55-R3	(20)	80,852,581.46	27,365,932	69,657,165	1,748,863	2.16	39.7
369.10	Services	50-R3	(50)	39,903,057.66	24,652,206	35,202,380	914,058	2.29	34.6
370.00	Meters	20-L3	(5)	19,046,181.82	5,381,770	14,616,721	1,411,209	7.41	10.8
371.00	Installation on Customers Premises	20-R0.5	(15)	3,568,525.72	(460,509)	4,564,313	339,557	9.52	16.6
373.00	Street Lighting System	43-R1	(45)	9,374,677.82	1,064,116	12,529,167	399,995	4.27	34.6
TOTAL DISTRIBUTION PLANT				461,078,839.18	158,081,479	521,805,714	15,005,624		
GENERAL PLANT									
390.00	Structures and Improvements	30-L0.5	10	1,731,943.78	915,629	643,120	26,631	1.54	20.6
391.10	Office Furniture and Equipment	15-SQ	0	141,255.83	74,384	66,872	11,728	8.30	5.8
391.30	Computer Equipment - PC	5-SQ	0	16,537.01	16,537	-	-	0.00	0.5
391.40	Computer Equipment - Prime	5-SQ	0	5,436.55	2,332	3,104	3,104	57.10	0.5
391.50	Computer Equipment - Other	10-SQ	0	70,687.28	31,380	39,307	8,555	12.10	5.0
392.10	Transportation Equipment - Trailers	25-R4	20	935,489.69	814,779	(66,387)	0	0.00	13.3
392.20	Transportation Equipment	11-L3	20	7,305,324.08	1,680,161	4,164,098	703,274	9.63	6.5
393.00	Stores Equipment	30-SQ	0	14,773.68	11,720	3,054	244	1.65	12.5
394.00	Tools, Shop & Garage Equipment	20-SQ	0	5,900,502.43	2,007,653	3,892,849	284,418	4.82	13.3
395.00	Laboratory Equipment	20-SQ	0	600,042.49	327,411	272,632	21,274	3.55	10.6
396.10	Work Equipment - Trailers	25-L3	0	864,269.49	363,232	501,037	25,373	2.94	18.1

Montana-Dakota Utilities Co. - Electric Division

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - TOTAL

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
396.20	Power Operated Equipment	9-L0	25	12,660,470.66	3,270,789	6,224,564	1,040,970	8.22	6.0
397.10	Radio Communication Equipment - Fixed	15-SQ	0	683,616.07	175,430	508,186	47,725	6.98	10.8
397.20	Radio Communication Equipment - Mobile	15-SQ	0	149,153.90	34,257	114,897	10,240	6.87	11.3
397.30	General Telephone Communication Equipment	10-SQ	0	9,878.47	9,146	733	733	7.42	0.5
397.50	Supervisory & Telemetering Equipment	10-SQ	0	55,692.93	35,080	20,613	7,948	14.27	2.7
397.60	SCADA System	10-SQ	0	1,680,102.35	335,583	1,344,520	164,471	9.79	8.1
397.80	Network Equipment	5-SQ	0	368,644.42	174,888	193,756	84,312	22.87	2.3
398.00	Miscellaneous Equipment	25-SQ	0	68,144.79	31,665	36,480	2,014	2.96	14.2
TOTAL GENERAL PLANT				33,261,965.90	10,312,058	17,963,433	2,443,013		
TOTAL DEPRECIABLE PLANT				1,941,233,414.01	571,292,976	1,687,611,412	57,828,801	2.98	
NON-DEPRECIABLE PLANT									
303.00	Miscellaneous Intangible Plant			13,321,691.43					
310.00	Land & Land Rights			1,015,061.73					
312.00	Acquisition Adjustment			10,387,642.47					
340.00	Land & Land Rights			38,532.61					
350.10	Transmission Land			1,790,068.76					
356.00	Acquisition Adjustment			80,697.00					
360.10	Distribution Land			3,323,414.68					
389.00	Land & Land Rights			38,849.70					
CLOSING PLANTS									
	Heskett I & II			111,011,494.71					
	Lewis & Clark I			73,522,157.87					
TOTAL NON-DEPRECIABLE PLANT				214,529,610.96					
TOTAL ELECTRIC PLANT				2,155,763,024.97					

* Annual Accrual and Remaining Life calculated on Location Schedules per EPH dates.

Montana-Dakota Utilities Co. - Electric Division

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - LIFE

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
STEAM PLANT									
311.00	Structures and Improvements	68-R3	-	81,113,617.27	37,840,342	43,273,275	1,599,729 *	1.97	- *
312.00	Boiler Plant Equipment	50-R1	-	198,020,003.63	78,534,155	119,485,849	5,252,395 *	2.65	- *
314.00	Turbogenerator Units	50-R0.5	-	63,076,279.95	24,326,382	38,749,898	1,490,694 *	2.36	- *
315.00	Accessory Electric Equipment	50-R2.5	-	20,863,863.43	9,795,524	11,068,339	479,222 *	2.30	- *
316.00	Miscellaneous Power Plant Equipment	30-R0.5	-	9,397,126.74	3,479,990	5,917,137	293,657 *	3.12	- *
TOTAL STEAM PRODUCTION PLANT				372,470,891.02	153,976,393	218,494,498	9,115,697		
OTHER PRODUCTION PLANT									
341.10	Structures and Improvements	70-R1	-	16,578,181.79	2,071,956	14,506,226	536,307 *	3.24	*
341.20	Structures and Improvements - Wind Farm	70-R1	-	42,546,921.10	5,675,437	36,871,484	1,981,332 *	4.66	*
341.51	Portable Generators	70-R1	-	169,459.16	42,894	126,565	5,132 *	3.03	- *
341.71	Ormat Generation Facility	70-R1	-	701,334.45	400,365	300,969	23,084 *	3.29	- *
342.00	Fuel Holders, Producers and Accessories	40-R4	-	5,640,437.75	1,239,809	4,400,629	181,339 *	3.21	- *
344.10	Generators	55-R3	-	103,677,534.12	32,876,006	70,801,528	2,811,895 *	2.71	- *
344.20	Generators - Wind Farm	55-R3	-	308,667,927.63	79,682,252	228,985,676	12,530,346 *	4.06	- *
345.10	Accessory Electric Equipment	25-L2	-	17,864,490.28	2,191,254	15,673,236	970,133 *	5.43	- *
345.20	Accessory Electric Equipment - Wind Farm	25-L2	-	51,401,813.40	5,433,845	45,967,968	3,124,300 *	6.08	- *
346.10	Miscellaneous Power Plant Equipment	28-S1	-	4,229,486.14	623,813	3,605,673	176,522 *	4.17	- *
346.20	Miscellaneous Power Plant Equipment - Wind Far	28-S1	-	660,514.98	127,731	532,784	34,188 *	5.18	- *
TOTAL OTHER PRODUCTION PLANT				552,138,100.80	130,365,362	421,772,738	22,374,578		
TRANSMISSION PLANT									
350.2	Land Rights	70-R4	-	15,602,605.19	2,382,259	13,220,346	201,419	1.29	62.8
352	Structures and Improvements	50-R2	-	329,102.63	7,581	321,522	6,709	2.04	48.4
353	Station Equipment	65-R2.5	-	222,333,780.46	50,411,109	171,922,671	3,040,859	1.37	54.2
354	Towers and Fixtures	60-R4	-	4,992,886.11	3,441,941	1,550,945	56,599	1.13	25.6
355	Poles and Fixtures	63-R2.5	-	172,142,521.86	26,534,708	145,607,814	2,536,591	1.47	55.7
356	Overhead Conductors and Devices	70-R3	-	101,836,280.32	25,181,965	76,654,315	1,199,571	1.18	59.1
357	Underground Conduit	50-R3	-	1,944,583.16	472,994	1,471,589	38,761	1.99	38.0
358	Underground Conductors and Devices	50-R3	-	3,101,857.38	540,422	2,561,435	67,480	2.18	38.0
TOTAL TRANSMISSION PLANT				522,283,617.11	108,972,980	413,310,637	7,147,989		
DISTRIBUTION PLANT									
360.2	Rights of Way	62-R3	-	961,139.62	663,409	297,731	7,959	0.83	32.5
362	Station Equipment	53-R2	-	89,780,857.62	20,430,755	69,350,102	1,602,245	1.78	42.3
364	Poles, Towers & Fixtures	60-R1.5	-	46,982,854.51	17,951,243	29,031,612	590,666	1.26	45.4
365	Overhead Conductor & Devices	65-R2	-	36,578,399.40	14,607,763	21,970,637	400,031	1.09	49.8
366	Underground Conduit	50-R3	-	235,918.03	124,248	111,670	3,750	1.59	26.5
367	Underground Conductor & Devices	42-R2.5	-	133,794,645.52	35,213,673	98,580,973	2,987,473	2.23	32.3
368	Line Transformers	55-R3	-	80,852,581.46	27,137,877	53,714,705	1,275,921	1.58	39.7
369.1	Services	50-R3	-	39,903,057.66	17,184,424	22,718,634	577,929	1.45	34.6
370	Meters	20-L3	-	19,046,181.82	5,508,654	13,537,528	1,302,567	6.84	10.8
371	Installation on Customers Premises	20-R0.5	-	3,568,525.72	(190,194)	3,758,720	270,835	7.59	16.6
373	Street Lighting System	43-R1	-	9,374,677.82	446,157	8,928,521	291,011	3.10	34.6
TOTAL DISTRIBUTION PLANT				461,078,839.18	139,078,007	322,000,832	9,310,387		
GENERAL Plant									
390	Structures and Improvements	30-L0.5	10	1,731,943.78	819,830	738,919	31,676	1.83	20.6
391.1	Office Furniture and Equipment	15-SQ	-	141,255.83	74,384	66,872	11,728	8.30	5.8
391.3	Computer Equipment - PC	5-SQ	-	16,537.01	16,537	-	-	0.00	0.5
391.4	Computer Equipment - Prime	5-SQ	-	5,436.55	2,332	3,104	3,104	57.10	0.5
391.5	Computer Equipment - Other	10-SQ	-	70,687.28	31,380	39,307	8,555	12.10	5.0
392.1	Transportation Equipment - Trailers	25-R4	20	935,489.69	814,779	(66,387)	0	0.00	13.3
392.2	Transportation Equipment	11-L3	20	7,305,324.08	1,680,161	4,164,098	703,274	9.63	6.5
393	Stores Equipment	30-SQ	-	14,773.68	11,720	3,054	244	1.65	12.5
394	Tools, Shop & Garage Equipment	20-SQ	-	5,900,502.43	2,007,653	3,892,849	284,418	4.82	13.3
395	Laboratory Equipment	20-SQ	-	600,042.49	327,411	272,632	21,274	3.55	10.6
396.1	Work Equipment - Trailers	25-L3	-	864,269.49	363,232	501,037	25,373	2.94	18.1

Montana-Dakota Utilities Co. - Electric Division

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - LIFE

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
396.2	Power Operated Equipment	9-L0	25	12,660,470.66	3,270,789	6,224,564	1,040,970	8.22	6.0
397.1	Radio Communication Equipment - Fixed	15-SQ	-	683,616.07	175,430	508,186	47,725	6.98	10.8
397.2	Radio Communication Equipment - Mobile	15-SQ	-	149,153.90	34,257	114,897	10,240	6.87	11.3
397.3	General Telephone Communication Equipment	10-SQ	-	9,878.47	9,146	733	733	7.42	0.5
397.5	Supervisory & Telemetering Equipment	10-SQ	-	55,692.93	35,080	20,613	7,948	14.27	2.7
397.6	SCADA System	10-SQ	-	1,680,102.35	335,583	1,344,520	164,471	9.79	8.1
397.8	Network Equipment	5-SQ	-	368,644.42	174,888	193,756	84,312	22.87	2.3
398	Miscellaneous Equipment	25-SQ	-	68,144.79	31,665	36,480	2,014	2.96	14.2
TOTAL GENERAL PLANT				33,261,965.90	10,216,259	18,059,232	2,448,058		
TOTAL DEPRECIABLE PLANT				1,941,233,414.01	542,609,001	1,393,637,938	50,396,709	2.60	

*Annual Accrual and Remaining Life calculated on Location Schedules per EPH dates.

Montana-Dakota Utilities Co. - Electric Division

TABLE 3. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - SALVAGE

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
STEAM PLANT								
311.00	Structures and Improvements	68-R3	0	81,113,617.27	-	-	-	0.00
312.00	Boiler Plant Equipment	50-R1	0	198,020,003.63	-	-	-	0.00
314.00	Turbogenerator Units	50-R0.5	0	63,076,279.95	-	-	-	0.00
315.00	Accessory Electric Equipment	50-R2.5	0	20,863,863.43	-	-	-	0.00
316.00	Miscellaneous Power Plant Equipment	30-R0.5	0	9,397,126.74	-	-	-	0.00
TOTAL STEAM PRODUCTION PLANT				372,470,891.02	-	-	-	
OTHER PRODUCTION PLANT								
341.10	Structures and Improvements	70-R1	0	16,578,181.79	-	-	-	
341.20	Structures and Improvements - Wind Farm	70-R1	0	42,546,921.10	-	-	-	
341.51	Portable Generators	70-R1	0	169,459.16	-	-	-	0.00
341.71	Ormat Generation Facility	70-R1	0	701,334.45	-	-	-	0.00
342.00	Fuel Holders, Producers and Accessories	40-R4	0	5,640,437.75	-	-	-	0.00
344.10	Generators	55-R3	0	103,677,534.12	-	-	-	0.00
344.20	Generators - Wind Farm	55-R3	0	308,667,927.63	-	-	-	0.00
345.10	Accessory Electric Equipment	25-L2	0	17,864,490.28	-	-	-	0.00
345.20	Accessory Electric Equipment - Wind Farm	25-L2	0	51,401,813.40	-	-	-	0.00
346.10	Miscellaneous Power Plant Equipment	28-S1	0	4,229,486.14	-	-	-	0.00
346.20	Miscellaneous Power Plant Equipment - Wind Far	28-S1	0	660,514.98	-	-	-	0.00
TOTAL OTHER PRODUCTION PLANT				552,138,100.80	-	-	-	
TRANSMISSION PLANT								
350.2	Land Rights	70-R4	0	15,602,605.19	-	-	-	0.00
352	Structures and Improvements	50-R2	0	329,102.63	2,523	(2,523)	(112)	-0.03
353	Station Equipment	65-R2.5	(10)	222,333,780.46	7,761,759	14,471,619	228,882	0.10
354	Towers and Fixtures	60-R4	(20)	4,992,886.11	99,604	898,974	38,447	0.77
355	Poles and Fixtures	63-R2.5	(35)	172,142,521.86	5,077,640	55,172,242	1,009,836	0.59
356	Overhead Conductors and Devices	70-R3	(20)	101,836,280.32	(3,575,537)	23,942,793	470,609	0.46
357	Underground Conduit	50-R3	0	1,944,583.16	-	-	-	0.00
358	Underground Conductors and Devices	50-R3	0	3,101,857.38	218,714	(218,714)	(5,762)	-0.19
TOTAL TRANSMISSION PLANT				522,283,617.11	9,584,702	94,264,391	1,741,900	
DISTRIBUTION PLANT								
360.2	Rights of Way	62-R3	0	961,139.62	-	-	-	0.00
362	Station Equipment	53-R2	(15)	89,780,857.62	3,100,558	10,366,570	238,955	0.27
364	Poles, Towers & Fixtures	60-R1.5	(120)	46,982,854.51	5,830,202	50,549,224	1,174,874	2.50
365	Overhead Conductor & Devices	65-R2	(110)	36,578,399.40	5,416,755	34,819,485	724,979	1.98
366	Underground Conduit	50-R3	0	235,918.03	2,627	(2,627)	(141)	-0.06
367	Underground Conductor & Devices	42-R2.5	(50)	133,794,645.52	(3,263,268)	70,160,591	2,461,151	1.84
368	Line Transformers	55-R3	(20)	80,852,581.46	228,056	15,942,461	472,941	0.58
369.1	Services	50-R3	(50)	39,903,057.66	7,467,782	12,483,747	336,129	0.84
370	Meters	20-L3	(5)	19,046,181.82	(126,884)	1,079,193	108,643	0.57
371	Installation on Customers Premises	20-R0.5	(15)	3,568,525.72	(270,314)	805,593	68,722	1.93
373	Street Lighting System	43-R1	(45)	9,374,677.82	617,959	3,600,646	108,984	1.16
TOTAL DISTRIBUTION PLANT				461,078,839.18	19,003,473	199,804,882	5,695,238	
GENERAL Plant								
390	Structures and Improvements	30-L0.5	10	1,731,943.78	95,799	(268,994)	(5,045)	-0.29
391.1	Office Furniture and Equipment	15-SQ	0	141,255.83	-	-	-	0.00
391.3	Computer Equipment - PC	5-SQ	0	16,537.01	-	-	-	0.00
391.4	Computer Equipment - Prime	5-SQ	0	5,436.55	-	-	-	0.00
391.5	Computer Equipment - Other	10-SQ	0	70,687.28	-	-	-	0.00
392.1	Transportation Equipment - Trailers	25-R4	20	935,489.69	-	(187,098)	-	0.00
392.2	Transportation Equipment	11-L3	20	7,305,324.08	-	(1,461,065)	-	0.00
393	Stores Equipment	30-SQ	0	14,773.68	-	-	-	0.00
394	Tools, Shop & Garage Equipment	20-SQ	0	5,900,502.43	-	-	-	0.00
395	Laboratory Equipment	20-SQ	0	600,042.49	-	-	-	0.00
396.1	Work Equipment - Trailers	25-L3	0	864,269.49	-	-	-	0.00
396.2	Power Operated Equipment	9-L0	25	12,660,470.66	-	(3,165,118)	-	0.00

Montana-Dakota Utilities Co. - Electric Division

TABLE 3. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - SALVAGE

Account	Depreciable Plant	Survivor Curve	Net Salvage	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
397.1	Radio Communication Equipment - Fixed	15-SQ	0	683,616.07	-	-	-	0.00
397.2	Radio Communication Equipment - Mobile	15-SQ	0	149,153.90	-	-	-	0.00
397.3	General Telephone Communication Equipment	10-SQ	0	9,878.47	-	-	-	0.00
397.5	Supervisory & Telemetering Equipment	10-SQ	0	55,692.93	-	-	-	0.00
397.6	SCADA System	10-SQ	0	1,680,102.35	-	-	-	0.00
397.8	Network Equipment	5-SQ	0	368,644.42	-	-	-	0.00
398	Miscellaneous Equipment	25-SQ	0	68,144.79	-	-	-	0.00
TOTAL GENERAL PLANT				33,261,965.90	95,799	(5,082,274)	(5,045)	
TOTAL DEPRECIABLE PLANT				1,941,233,414.01	28,683,974	288,986,999	7,432,092	0.38

Montana-Dakota Utilities Co. - Electric Division - Generation Plant

TABLE 5. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - LIFE

Account	Location	Depreciable Plant	Survivor Curve	Net Salvage	Truncation Date	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
STEAM PLANT											
311.00		Structures and Improvements									
		Heskett Common Station	68-R3	-		9,556,243.25	5,773,921	3,782,323	61,014	0.64	54.5
		Lewis & Clark Common Station	68-R3	-		4,899,289.52	392,969	4,506,320	69,411	1.42	63.8
	8300	Coyote Generating Station	68-R3	-	2041	29,775,617.47	22,251,079	7,524,539	388,451	1.30	18.8
	8610	Big Stone Generating Station	68-R3	-	2046	33,163,446.92	8,713,452	24,449,995	1,000,759	3.02	24.1
	8720	Wygen III Generating Station	68-R3	-	2060	3,719,020.11	708,921	3,010,099	80,095	2.15	37.6
Total Structures and Improvements						81,113,617.27	37,840,342	43,273,275	1,599,729		
312.00		Boiler Plant Equipment									
		Heskett Common Station	50-R1	-		939,193.88	578,061	361,133	8,657	0.92	40.4
		Lewis & Clark Common Station	50-R1	-		298,181.67	103,148	195,034	4,209	1.41	44.4
	8300	Coyote Generating Station	50-R1	-	2041	81,965,766.43	56,012,330	25,953,437	1,464,728	1.79	16.9
	8610	Big Stone Generating Station	50-R1	-	2046	85,685,287.65	16,448,927	69,236,361	3,038,043	3.55	22.7
	8720	Wygen III Generating Station	50-R1	-	2060	29,131,574.00	5,391,690	23,739,884	736,758	2.53	32.2
Total Boiler Plant Equipment						198,020,003.63	78,534,155	119,485,848	5,252,395		
314.00		Turbogenerator Units									
		Heskett Common Station	50-R0.5	-		1,062,175.62	982,446	79,730	1,716	0.16	18.6
		Lewis & Clark Common Station	50-R0.5	-		237,574.36	90,104	147,471	3,293	1.39	41.9
	8300	Coyote Generating Station	50-R0.5	-	2041	18,314,529.41	10,016,941	8,297,589	463,376	2.53	17.5
	8610	Big Stone Generating Station	50-R0.5	-	2046	13,525,236.19	8,941,985	4,583,252	209,242	1.55	20.8
	8720	Wygen III Generating Station	50-R0.5	-	2060	29,936,764.37	4,294,907	25,641,857	813,066	2.72	31.5
Total Turbogenerator Units						63,076,279.95	24,326,382	38,749,898	1,490,694		
315.00		Accessory Electric Equipment									
	8300	Coyote Generating Station	50-R2.5	-	2041	8,916,346.70	6,759,094	2,157,252	127,318	1.43	15.7
	8610	Big Stone Generating Station	50-R2.5	-	2046	8,947,155.15	3,435,766	5,511,389	251,879	2.82	20.7
	8720	Wygen III Generating Station	50-R2.5	-	2060	3,000,361.58	(399,337)	3,399,698	100,025	3.33	34.0
Total Accessory Electric Equipment						20,863,863.43	9,795,524	11,068,340	479,222		
316.00		Miscellaneous Power Plant Equipment									
		Heskett Common Station	30-R0.5	-		2,508,360.55	683,452	1,824,909	68,382	2.73	25.8
		Lewis & Clark Common Station	30-R0.5	-		1,300,001.27	498,180	801,821	28,661	2.20	25.7
	8300	Coyote Generating Station	30-R0.5	-	2041	3,776,499.87	1,511,638	2,264,862	145,199	3.84	14.9
	8610	Big Stone Generating Station	30-R0.5	-	2046	1,649,259.12	774,901	874,358	45,604	2.77	16.4
	8720	Wygen III Generating Station	30-R0.5	-	2060	163,005.93	11,820	151,186	5,812	3.57	26.0
Total Miscellaneous Power Plant Equipment						9,397,126.74	3,479,990	5,917,136	293,657		
TOTAL STEAM PRODUCTION PLANT						372,470,891.02	153,976,394	218,494,497	9,115,697		
OTHER PRODUCTION PLANT											
341.10		Structures and Improvements									
		Heskett Turbine	70-R1	-	2057	7,104,332.12	126,719	6,977,613	211,098	2.97	33.1
		Glendive Turbine Common	70-R1	-	2046	2,413,718.75	872,750	1,540,969	64,559	2.67	23.8
		Miles City Turbine	70-R1	-	2033	223,817.35	195,239	28,578	2,356	1.05	12.1
		Lewis & Clark RICE	70-R1	-	2045	6,836,313.57	877,247	5,959,066	258,294	3.78	23.1
Total Structures and Improvements						16,578,181.79	2,071,956	14,506,226	536,307		
341.20		Structures and Improvements - Wind Farm									
		Diamond Willow Wind Farm	70-R1	-	2035	3,621,426.04	1,908,197	1,713,229	122,645	3.39	14.0
		Thunder Spirit Wind Farm II	70-R1	-	2043	8,482,596.26	28,527	8,454,069	395,472	4.66	21.4
		Cedar Hills Wind Farm	70-R1	-	2035	2,970,920.55	1,347,079	1,623,841	116,135	3.91	14.0
		Thunder Spirit Wind Farm I	70-R1	-	2040	27,471,978.25	2,391,634	25,080,344	1,347,080	4.90	18.6
Total Structures and Improvements						42,546,921.10	5,675,437	36,871,484	1,981,332		
341.50		Structures and Improvements - Generators									
341.51		Portable Generators	70-R1	-	2047	169,459.16	42,894	126,565	5,132	3.03	24.7
341.71		Ormat Generation Facility	70-R1	-	2034	701,334.45	400,365	300,969	23,084	3.29	13.0
Total Structures and Improvements - Generators						870,793.61	443,260	427,534	28,216		
342.00		Fuel Holders, Producers and Accessories									
		Glendive Turbine - Common	40-R4	-	2046	1,257,109.34	710,772	546,338	25,357	2.02	21.1
		Lewis & Clark RICE	40-R4	-	2045	2,984,778.90	383,769	2,601,010	109,106	3.66	23.8

Montana-Dakota Utilities Co. - Electric Division - Generation Plant

TABLE 5. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2020 - LIFE

Account	Location	Depreciable Plant	Survivor Curve	Net Salvage	Truncation Date	Original Cost at Dec 31, 2020	Book Depreciation Reserve	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
		Miles City Turbine	40-R4	-	2033	161,610.88	92,130	69,481	8,664	5.36	8.0
		Portable Generators	40-R4	-	2047	135,973.35	33,942	102,032	4,087	3.01	25.0
		Heskett Turbine	40-R4	-	2057	1,100,965.28	19,197	1,081,769	34,125	3.10	31.7
Total Fuel Holders, Producers, And Accessories						5,640,437.75	1,239,809	4,400,629	181,339		
344.10		Generators									
	8510	Glendive Turbine 1	55-R3	-	2033	6,830,097.08	6,598,436	231,662	18,712	0.27	11.2
	8512	Glendive Turbine 2	55-R3	-	2046	16,508,744.93	5,648,406	10,860,339	454,730	2.75	23.9
		Miles City Turbine	55-R3	-	2033	3,687,157.84	2,663,648	1,023,510	82,541	2.24	11.1
		Lewis & Clark RICE	55-R3	-	2045	25,874,335.21	3,320,238	22,554,097	941,492	3.64	24.0
		Portable Generators	55-R3	-	2047	1,206,071.50	264,192	941,879	36,818	3.05	25.6
		Ormat Generating Facility	55-R3	-	2034	12,174,693.92	6,677,480	5,497,214	412,896	3.39	13.3
		Heskett Turbine	55-R3	-	2057	37,396,433.64	7,703,607	29,692,827	864,706	2.31	34.3
Total Generators						103,677,534.12	32,876,006	70,801,528	2,811,895		
344.20		Generators - Wind Farm									
		Diamond Willow Wind Farm	55-R3	-	2035	62,745,085.83	23,011,969	39,733,117	2,773,965	4.42	14.3
		Thunder Spirit Wind Farm II	55-R3	-	2043	69,802,607.62	7,337,837	62,464,771	2,814,556	4.03	22.2
		Cedar Hills Wind Farm	55-R3	-	2035	35,044,708.58	15,715,304	19,329,404	1,351,947	3.86	14.3
		Thunder Spirit Wind Farm I	55-R3	-	2040	141,075,525.60	33,617,141	107,458,384	5,589,878	3.96	19.2
Total Generators - Wind Farm						308,667,927.63	79,682,252	228,985,676	12,530,346		
345.10		Accessory Electric Equipment									
	8510	Glendive Turbine - Common	25-L2	-	2046	1,713,112.75	-	1,713,113	123,969	7.24	14.8
	8520	Glendive Turbine 2	25-L2	-	2046	472,685.81	131,729	340,957	17,033	3.60	20.0
		Miles City Turbine	25-L2	-	2033	1,006,677.50	25,453	981,224	83,248	8.27	11.8
		Lewis & Clark RICE	25-L2	-	2045	5,701,040.81	731,567	4,969,474	288,843	5.07	17.2
		Portable Generators	25-L2	-	2047	532,801.74	187,391	345,410	22,400	4.20	15.4
		Ormat Generation Facility	25-L2	-	2034	2,207,374.62	1,250,666	956,709	93,488	4.24	10.2
		Heskett Turbine	25-L2	-	2057	6,230,797.05	(135,552)	6,366,349	341,153	5.48	18.7
Total Accessory Electric Equipment						17,864,490.28	2,191,254	15,673,236	970,133		
345.20		Accessory Electric Equipment - Wind Farm									
		Diamond Willow Wind Farm	25-L2	-	2035	7,841,019.30	3,605,143	4,235,877	393,657	5.02	10.7
		Thunder Spirit Wind Farm II	25-L2	-	2043	6,659,678.51	22,397	6,637,282	364,390	5.47	18.2
		Cedar Hills Wind Farm	25-L2	-	2035	6,024,098.89	2,719,916	3,304,183	297,532	4.94	11.1
		Thunder Spirit Wind Farm I	25-L2	-	2040	30,877,016.70	(913,610)	31,790,627	2,068,721	6.70	15.4
Total Accessory Electric Equipment - Wind Farm						51,401,813.40	5,433,845	45,967,969	3,124,300		
346.10		Miscellaneous Power Plant Equipment									
		Glendive Turbine - Common	28-S1	-	2046	234,220.26	114,727	119,493	6,546	2.79	17.0
		Miles City Turbine	28-S1	-	2033	57,866.62	30,081	27,786	2,376	4.11	10.7
		Lewis & Clark RICE	28-S1	-	2045	2,368,901.74	303,958	2,064,944	107,838	4.55	19.1
		Heskett Turbine	28-S1	-	2057	1,568,497.52	175,046	1,393,451	59,761	3.81	23.4
Total Miscellaneous Power Plant Equipment						4,229,486.14	623,813	3,605,673	176,522		
346.20		Miscellaneous Power Plant Equipment - Wind Farm									
		Diamond Willow Wind Farm	28-S1	-	2035	74,569.00	35,276	39,293	3,198	4.29	12.1
		Thunder Spirit Wind Farm II	28-S1	-	2043	819.71	3	817	42	5.14	19.4
		Cedar Hills Wind Farm	28-S1	-	2035	146,776.28	34,877	111,900	8,527	5.81	13.1
		Thunder Spirit Wind Farm I	28-S1	-	2040	438,349.99	57,576	380,774	22,421	5.11	17.0
Total Miscellaneous Power Plant Equipment - Wind Farm						660,514.98	127,731	532,784	34,188		
TOTAL OTHER PRODUCTION PLANT						552,138,100.80	130,365,362	421,772,739	22,374,580		
TOTAL DEPRECIABLE PLANT						924,608,991.82	284,341,755	640,267,236	31,490,277	3.41	

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

Direct Testimony and Exhibits

of

Michael J. Adams

Cash Working Capital / Lead-Lag Study

November 4, 2022

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. PLEASE DESCRIBE CONCENTRIC.

A. Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As a consultant, my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. PLEASE DESCRIBE YOUR EDUCATION.

A. I have an MBA from the University of Illinois – Springfield and a BS in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I have over thirty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements. A statement of my background and qualifications is attached as Exhibit MJA-1.

Q. HAVE YOU EVER TESTIFIED IN A REGULATORY PROCEEDING?

A. Yes. I have provided expert testimony or reports before the Arizona Corporation Commission; Arkansas Public Service Commission; the City of El Paso; the Connecticut Public Utilities Regulatory Authority, the Federal Energy Regulatory Commission (FERC); the Georgia Public Service Commission; the Hawaii Public Utility Commission; the Idaho Public Utilities Commission; the Illinois Commerce Commission; the Maine Public Utilities Commission; the Maryland Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Missouri Public Service Commission; the New Hampshire Public Utilities Commission; the New Mexico Public Regulation Commission; the State of New Jersey Board of Public Utilities; the Oklahoma Corporation Commission; the Ontario Energy Board; the Pennsylvania Public

Utility Commission; the Tennessee Public Utility Commission; the Public Utility Commission of Texas; the State Corporation Commission of Virginia; and the Public Service Commission of West Virginia.

My testimonies typically address issues related to cost of service/revenue requirement, shared services, accounting and/or cost allocations.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I have been asked by Montana-Dakota Utilities ("MDU" or the "Company") to discuss a lead-lag study that was used to develop cash working capital ("CWC") factors and ultimately to calculate the cash working capital requirements of the Company. Discussion of the study follows.

III. Cash Working Capital Requirement and Lead-Lag Study

Q. PLEASE DEFINE WHAT YOU MEAN BY THE PHRASE "CASH WORKING CAPITAL."

A. Cash working capital is the amount of funds required to finance the day-to-day operations of the Company.

Q. ARE YOU SPONSORING AN EXHIBIT IN THIS PROCEEDING RELATED TO YOUR ANALYSIS OF CASH WORKING CAPITAL?

A. Yes. Exhibit MJA-2 has been prepared under my direction and supervision and is accurate and complete to the best of my knowledge and belief. Specifically, the Exhibit shows the revenue lag and expense leads.

Q. FOR WHAT PERIOD WAS THE LEAD-LAG STUDY PERFORMED?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2020. The leads and lags were applied to expense amounts for the Test Year.

Q. HOW SHOULD THE RESULTS OF THE CASH WORKING CAPITAL ANALYSIS BE TREATED FOR RATEMAKING PURPOSES?

A. The cash working capital requirements should be included as part of MDU's rate base for ratemaking purposes. The total amount of cash working capital supported by this study is negative $940,176. The determination of the amount of cash working capital requirement is shown Adjustment M, located in Rule 38.5.143, Statement E, page 11.

Q. IS THE ANALYSIS OF THE REVENUE LAGS AND EXPENSE LEADS TYPICALLY REFERRED TO AS A LEAD-LAG STUDY?

A. Yes. Cash working capital requirements are generally determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date. The "lead" and "lag" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is then included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied in this proceeding are described in the testimony of Company witness Vesey.

Q. WHAT ARE THE VARIOUS LEADS AND LAGS THAT WERE CONSIDERED IN THE CASH WORKING CAPITAL ANALYSIS?

A. Two broad categories of leads and lags were considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company, as well as the various taxes and other expenses paid by the Company ("expense leads").

Q. WHAT IS A REVENUE LAG?

A. A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., gas or electricity) and its ability to use the funds received as payment for the delivery of the product.

Q. WHAT IS AN EXPENSE LEAD?

A. The expense lead refers to the elapsed time from when a good or service is provided to a company to the point in time when the company pays for the good or service and the funds are no longer available to the company.

Q. WHAT WAS THE SOURCE OF INFORMATION YOU EMPLOYED TO DETERMINE THE LEADS AND LAGS IN YOUR CASH WORKING CAPITAL ANALYSIS?

A. Information from the Company was utilized, including data from their Accounts Payable, Customer Service, Human Resources, Payroll, and Tax systems. The information derived from these sources, together with analyses of specific transactions, led to the determination of the appropriate number of lead-lag days for MDU.

A. Revenue Lag

Q. HOW WAS THE REVENUE LAG DETERMINED?

A. The revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company. In the calculation, the revenue lag was divided into three distinct components: 1) service lag; 2) billing lag; and 3) collections lag. An explanation of each component of the revenue lag follows.

Q. WHAT IS MEANT BY SERVICE LAG?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for that service period. Using the mid-point methodology, the average lag associated with the provisioning of service was 15.21 days (365 days in the year divided by 12 months divided by 2).

Q. WHAT IS MEANT BY BILLING LAG?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's monthly billing schedules and meter reading records. The average billing lag was conservatively determined to be 1.00 day.

Q. WHAT IS MEANT BY COLLECTIONS LAG?

A. The collections lag refers to the average amount of time from the date when the customer received a bill to the date that the Company received payment from its customers. For purposes of the cash working capital analyses, the Company's actual customer receivables during the twelve months ended December 31, 2020, were analyzed to determine the collections lag. Based on weighted average data from the Company and by considering accounts receivables balances by days aged, the average collection lag was determined to be 33.77 days.

Q. EXPLAIN THE COMPANY'S CALCULATION OF THE COLLECTION LAG.

A. The monthly accounts receivable data was categorized into aging "buckets" of 0-30 days, 30-60 days, 60-90 days, 90-120 days and 120+ days. For purposes of calculating the collection lag, I have assumed the customers will pay their bills ratably over the month. Therefore, the midpoint of the first month is 15 days (*i.e.*, 30 divided by 2). I apply the same assumption that customers will pay their bills ratably over the course of the month to each aging bucket. It is assumed that customers will pay their bills ratably over the course of the second month (the month that is 30-60 days after the bill was issued). Therefore, the midpoint of payments that are received 30-60 days after the bill is issued is 45 days (*i.e.*, 30 days outstanding from the first month plus the 15-day midpoint of the second month = 45 days). This same theory applies to the use of 75 day for payments that are received 60-90 days after the bill is issued as well as the use of 105 days for the 90-120 days period. Receivables outstanding for 120 days or longer were capped at 120 days. The accounts receivable dollars in each bucket are then multiplied by the midpoint of each bucket to calculate the collections lag.

Q. PLEASE SUMMARIZE THE CALCULATION OF BASE REVENUE LAG DAYS.

A. The overall base revenue lag, by lag component, is summarized in the following table.

Revenue Lag by Component	
Service Lag	15.21
Billing Lag	1.00
Collections Lag	33.77
Total Lag	**49.98**

B. Expense Leads

Q. WHAT EXPENSE-RELATED LEADS WERE CONSIDERED IN THE LEAD-LAG ANALYSIS?

A. Lead times associated with the following expense categories were considered in the lead-lag study: a) payroll and withholdings; b) payroll taxes; c) employee benefits; d) other O&M; e) fuel and purchased power; f) general taxes other than income taxes; g) federal income taxes; h) state income taxes; i) interest on long-term debt; j) short-term on commercial paper, notes payable and commitment fees.

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEADS ASSOCIATED WITH THE COMPANY'S PAYROLL AND WITHHOLDINGS EXPENSES.

A. Employees of MDU are paid on Fridays, approximately twelve days after the end of the pay period. The Company remits the payroll withholdings approximately 3 days after the end of the pay period. This results in a dollar weighted average expense lead of 19.75 days for payroll and withholdings expenses.

Q. WHAT PAYROLL RELATED TAXES DOES THE COMPANY PAY?

A. The Company pays the following payroll-related taxes: (1) Federal Employment; (2) State Unemployment; and (3) Workers Compensation. The dollar-weighted expense lead for all of these taxes was determined to be 19.13 days.

Q. WHAT EMPLOYEE BENEFITS DOES THE COMPANY PROVIDE AND WHAT IS THE EXPENSE LEAD ASSOCIATED WITH SUCH BENEFITS?

A. The Company provides benefits associated with medical, dental, life, long-term disability insurance as well as health savings accounts, employee assistance programs and 401(k) matching. The dollar-weighted expense lead for these benefits was determined to be 13.06 days.

Q. WHAT ARE OTHER O&M EXPENSES AND WHAT LEAD TIMES WERE ASSOCIATED WITH SUCH EXPENSES?

A. The Company engages in transactions with other vendors for a variety of purposes including facility maintenance, system maintenance, and customer service. Accounts payable data was analyzed in order to calculate a lead time associated with payment for services related to other operations and maintenance activities. The analysis indicates that on average, invoices were paid by the Company 41.55 days after receipt. This lead time includes a service lead time.

Q. WHAT IS THE EXPENSE LEAD TIME ASSOCIATED WITH THE COMPANY'S FUEL AND PURCHASED POWER EXPENSE?

A. The Company purchases coal and natural gas for Company-generated power. It also purchases power from the Midcontinent Independent System Operator ("MISO") and has transmission service in Southwest Power Pool ("SPP"). Based on an examination of the service periods and payment dates for the Company's sources of purchased power, a weighted expense lead time of 5.24 days was determined.

Q. WHAT ARE THE VARIOUS GENERAL TAXES CONSIDERED IN THE ANALYSIS?

A. The following general taxes were considered in the study: a) Property Tax; b) Public Service Regulation Fee; c) Consumer Counsel Fee; d) Electrical Energy License Tax; e) Wholesale Energy Transaction Tax; f) Ft. Peck Tribal Tax; g) Highway Use Tax; h) Electric Wind Generation Tax; i) Secretary of State Tax; j) Coal Conversion Tax; and k) Delaware Franchise Fee Tax.

Q. EXPLAIN THE LEAD EFFECTS ASSOCIATED WITH EACH TYPE OF GENERAL TAXES CONSIDERED IN THE ANALYSIS.

A. The treatment of each category of general taxes in the study is described below:

a) Property Tax: Taking the semi-annual periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the property tax payments, a dollar-weighted expense lead of 251.30 days was determined.

b) Public Service Regulation Fee: Taking the quarterly periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the Public Service Regulation Fee payments, a dollar-weighted expense lead of 73.46 days was determined.

c) Consumer Counsel Fee: Taking the quarterly period for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the property tax payments, a dollar-weighted expense lead of 73.46 days was determined.

d) Electrical Energy License Tax: Taking the quarterly period for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the Electrical Energy License tax payments, a dollar-weighted expense lead of 73.98 days was determined.

e) Wholesale Energy Transaction Tax: Taking the quarterly period for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the Wholesale Energy Transaction tax payments, a dollar-weighted expense lead of 74.00 days was determined.

f) Ft. Peck Tribal Tax: Taking the annual period for which the tax is assessed, as well as the timing of the actual payment date and amount into consideration for the tax payment, a dollar-weighted expense lead of 377.33 days was determined.

g) Highway Use Tax: This is the IRS Form 2290, heavy highway vehicle use tax return which is the tax on highway motor vehicles used during the tax period. Taking the annual period for which the tax is assessed, as well as the timing of the actual payment date and amount into consideration for the tax payment, a dollar-weighted expense lead of negative 148.50 days was determined.

h) Electric Wind Generation Tax: This is a tax on the Company's Thunder Spirit wind farm. The first part of the tax is based on rated capacity and the second part of the tax is based on kilowatts that were generated for the year. The expense lead was calculated to be 180.83 days.

i) Secretary of State Tax: If a company has received authority to do business in a State, the Secretary of State's Office will require an annual or biennial report to be filed by the Company to keep the Company's status in "good standing." If these reports are not filed, the company's authority to do business in that State will be revoked. The dollar-weighted expense lead associated with the Secretary of State Tax was calculated to be 8.16 days.

j) Coal Conversion Tax: This is a tax in lieu of property taxes and is imposed on coal conversion facilities. It is a two-part tax where the first tax is imposed on the installed capacity and the second part is based on kWh available for sale. Based upon the due dates, the expense lead associated with the Coal Conversion Tax was calculated to be 0.84 days.

k) Delaware Franchise Fee Tax: Montana-Dakota Co. was incorporated in the State of Delaware, so this is a franchise fee which is due each year. The tax is based on authorized shares. Based upon the due dates, the expense lead associated with the Delaware Franchise Fee Tax was calculated to be 106.18 days.

Q. HOW DID YOUR STUDY ADDRESS FEDERAL INCOME TAXES?

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code that require estimated tax payments of 25 percent of total income taxes due each quarter of the current year. Taking this schedule into consideration a lead time of 38.00 days for federal income taxes was determined.

Q. HOW DID THE STUDY ADDRESS STATE INCOME TAXES?

A. The Company makes quarterly payments to the state. Taking this statutory payment schedule into consideration, an expense lead time of 38.00 days for state income tax payments was determined. Since payments are made electronically, no additional float time was included.

Q. PROVIDE A DESCRIPTION OF HOW LEAD TIMES ASSOCIATED WITH THE COMPANY'S LONG-TERM INTEREST EXPENSES WERE ADDRESSED BY THE STUDY.

A. The Company made semi-annual interest payments on its long-term debt throughout the test year. Using the midpoints of the semi-annual service periods, a dollar-weighted lead of 91.50 days for long-term interest payments was determined.

Q. DID YOU ALSO CALCULATE THE LEAD TIMES ASSOCIATED WITH THE COMPANY'S SHORT-TERM INTEREST EXPENSE?

A. Yes. The Company made periodic interest payments on three different types of short-term debt throughout the test year. The debt instruments included 1) term loan commercial paper; 2) a Montana Air Force Base ("MAFB") note payable associated with the purchase of the Base; and 3) commitment fees paid associated with short-term debt. Using the midpoints of the service periods, a combined dollar-weighted lead of 30.26 days for short-term interest payments was determined.

Q. BASED UPON THE RESULTS OF THE LEAD-LAG STUDY AND THE LEVEL OF EXPENSES SPONSORED BY COMPANY WITNESS VESEY, WHAT LEVEL OF CASH WORKING CAPITAL REQUIREMENTS SHOULD BE INCLUDED IN MDU'S RATE BASE?

A. As shown on Adjustment M, a cash working capital requirement of $(940,176) should be included in the Company's rate base.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

MICHAEL J. ADAMS

Mr. Adams has over thirty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry.

While employed by Illinois Power Company, Mr. Adams monitored project expenditures associated with gas and electric distribution, transmission, and generation capital projects.

While employed by the Illinois Commerce Commission, Mr. Adams initially evaluated the rate filings of regulated utilities and provided expert testimony regarding the reasonableness of the requests. Mr. Adams was subsequently charged with developing and managing a management and operations audit program to evaluate company management policies, procedures, and performance, as well as operational efficiency and effectiveness. Mr. Adams served as the Deputy Executive Director of the agency at the time of his departure. As a consultant, Mr. Adams has provided consulting services to regulatory agencies and regulated utilities on an array of operational and financial issues since 1995.

Prior to joining Concentric, Mr. Adams was a Managing Director of Navigant Consulting, Inc. Mr. Adams is a Certified Public Accountant, a graduate of Illinois College and holds an M.B.A. from the University of Illinois, Springfield.

Mr. Adams provides financial, regulatory, strategic, operational and litigation support to his energy clients. provides a wide array of services to his energy clients in preparation for, and support of regulatory filings. He has assisted clients with regulatory/legislative initiatives related to the approval and implementation of alternative regulation plans as well as the preparation and support of regulatory filings under alternative rate plans. Mr. Adams also provides advisory services in the areas of mergers and acquisitions. As a consultant, Mr. Adams has provided expert testimony or reports before State and Federal regulatory agencies.

Senior Vice President

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc.

Senior Vice President

Vice President

Navigant Consulting, Inc.

Managing Director

L.E. Burgess Consultants, Inc.

Illinois Commerce Commission

Accounting/Rate Case Staff

Director, Management Audit/Studies

Deputy Executive Director

Illinois Power Company

Accounting/Auditing Department

EDUCATION

University of Illinois at Springfield

M.B.A., Finance

Illinois College

B.S., Accounting

REPRESENTATIVE PROJECT EXPERIENCE

AUDITS/SPECIAL STUDIES

- Management audits
- Regulatory reviews/audits
- Project performance monitoring/reviews
- Prudence reviews
- A&G Capitalization Studies
- Commission ordered studies
- Audit prep and support
- Project controls and assessments

Affiliate Transactions

- Code of Conduct
- Shared Services reviews
- Cost controls

Benchmarking

- O&M costs
- Capital expenditures
- Shared Services

- Operational performance
- Customer service
- Reliability

DUE DILIGENCE/LITIGATION/SPECIAL PROJECTS

- Assessment of cost controls
- Financial outlook
- Historical/future performance assessment
- Merger Synergies
- Regulatory environment/assessment

EXPERT WITNESS

- Regulatory proceedings
- Civil litigation

LITIGATION SUPPORT

- Data review and analyses
- Position development and review
- Research
- Expert testimony and reports

REGULATORY PROCEEDINGS

- Revenue Requirement
- Cash working capital
- Benchmarking
    - O&M
    - Capital
    - Shared Services
- Case development/management
- Multi-year rate plans
- Research
- Performance based regulation

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant

American Institute of Public Accountants

Illinois Society of Certified Public Accountants

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Liberty Utilities	2022	Liberty Utilities	SW-04316A-21-0325, SW-02519A-21-0326, SW-04316A-21-0359	Capitalization rate for indirect overheads
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2002	Arkansas Oklahoma Gas Corporation	02-024-U	Reasonableness of ratemaking adjustments
Centerpoint Energy Arkla	2005	Centerpoint Energy Arkla	04-121-U	Cash Working Capital
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas	2013	Connecticut Natural Gas	13-06-08	Cash Working Capital
United Illuminating Company	2022	United Illuminating Company	22-08-08	Cash Working Capital
Federal Energy Regulatory Commission				
Granite State Gas Transmission	2010	Granite State Gas Transmission	RP10-896	Revenue Requirement
Georgia Public Service Commission				
Atlanta Gas Light Company	2019	Granite State Gas Transmission	42315	Cash Working Capital
Hawaii Public Utilities Commission				
Hawaii Electric Light Company, Inc.	2005	Hawaii Electric Light Company, Inc.	05-0315	Allowance for Funds Used During Construction
Idaho Public Utilities Commission				
Intermountain Gas Company	2016	Intermountain Gas Company	INT-G-16-2	Cash working capital, prepared/supported benchmarking for client
Illinois Commerce Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Power Company	1999	Illinois Power Company	99-0120/99-0134 (Cons.)	Functionalization/Unbundling of General and Intangible Assets and Administrative and General expenses.
Illinois Power Company	2004	Illinois Power Company	04-0476	Cash working capital and asset separation
Ameren Illinois Utilities	2006	Ameren Illinois Utilities	06-0070/06-0071/06-0072 (Cons.)	Functionalization of Assets, Cash Working Capital, Shared Services Costs, Benchmarking
Ameren Illinois Utilities	2007	Ameren Illinois Utilities	07-0585/07-0586/07-0587/ 07-0588/07-0589/07-0590 (Cons.)	Shared Services Costs, Asset Separation, Cash Working Capital
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0103	Cash working capital requirements associated with procurement of electric power and energy
The Peoples Gas Light and Coke Company, Inc. and North Shore Gas Company	2007	The Peoples Gas Light and Coke Company, Inc. and North Shore Gas Company	07-0241/07-0242 (Cons.)	Cash working capital
Northern Illinois Gas Company	2008	Northern Illinois Gas Company	08-0363	Cash working capital
Ameren Illinois	2015	Ameren Illinois	16-0262	Benchmarking of Utility Performance
Maine Public Utilities Commission				
Emera Maine	2017	Emera Maine	Docket No. 2017-00198	Cash working capital
Versant Power	2020	Versant Power	Docket No. 2020-00316	Cash working capital
Maryland Public Service Commission				
Constellation Energy	2009	Constellation Energy	Case No. 9173, Phase II	Shared Services, Benchmarking
Massachusetts Department of Public Utilities				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Massachusetts Distribution Companies	2002	Massachusetts Distribution Companies	DTE-99-84	Reliability standards and the appropriateness of utilizing data for benchmarking purposes
Missouri Public Service Commission				
AmerenUE (Union Electric Company)	2002	AmerenUE (Union Electric Company)	EC-2002-001	Cash working capital
AmerenUE	2003	AmerenUE	GR-2003-0517	Cash working capital
AmerenUE	2007	AmerenUE	ER-2007-0002	Cash working capital
AmerenUE	2008	AmerenUE	ER-2008-0318	Cash working capital
Missouri Gas Energy	2006	Missouri Gas Energy	GR-2006-0422	Cash working capital
Ameren Missouri Gas	2010	Ameren Missouri Gas	GR-2010-0363	Cash working capital
Ameren Missouri Electric	2010	Ameren Missouri Electric	ER-2011-0028	Cash working capital
Ameren Missouri	2012	Ameren Missouri	ER-2012-0166	Cash working capital
Ameren Missouri	2014	Ameren Missouri	ER-2014-0258	Affiliate transactions, Benchmarking
Evergy Metro, Inc. and Evergy Missouri West	2022	Evergy Metro, Inc. and Evergy Missouri West	ER-2022-0129 and ER-2022-130	Cash working capital, Property Tax Tracker
New Hampshire Public Utilities Commission				
National Grid Energy North	2010	National Grid Energy North	DG 10-017	Revenue Requirement
New Mexico Public Utility Regulation Commission				
New Mexico Gas Company	2019	New Mexico Gas Company	19-00317-UT	NMGC's future test year cost of service model
State of New Jersey Board of Public Utilities				
PSEG	2018	PSEG	ER18010029 & GR18010030	Benchmarking
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	2003	Arkansas Oklahoma Gas Corporation	PUD200300088	Cash working capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ontario Energy Board				
Hydro One Distribution Business	2005	Hydro One Distribution Business	-	Cash working capital
Hydro One Transmission Business	2006	Hydro One Transmission Business	-	Cash working capital
Toronto Hydro	2006	Toronto Hydro	-	Cash working capital
Pennsylvania Public Utility Commission				
Allegheny Power	2004	Allegheny Power	M-00991220	Reliability data and reasonableness of established standards
T.W. Phillips Gas and Oil Company, Inc.	2006	T.W. Phillips Gas and Oil Company, Inc.	R-00051178	Cash working capital
Tennessee Public Utility Commission				
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash working capital
Public Utility Commission of Texas				
Texas-New Mexico Power Company	2008	Texas-New Mexico Power Company	36025	Revenue Requirement
El Paso Electric Company	2012	El Paso Electric Company	40094	O&M Benchmarking
El Paso Electric Company	2014	El Paso Electric Company	-	Benchmarking of New Generation Costs
El Paso Electric Company	2015	El Paso Electric Company	44941	Benchmarking of costs of new generation units
Public Service Commission of West Virginia				
Appalachian Power Company	2018	Appalachian Power Company	18-0646-E-42T	Cash Working Capital
Tennessee Public Utility Commission				
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash Working Capital
Virginia State Corporation Commission				
Virginia Natural Gas	2012	Virginia Natural Gas	PUE-2010-00142	Cash Working Capital
Virginia Natural Gas	2017	Virginia Natural Gas	-	Shared Services Review, Benchmarking, Cash

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
				Working Capital
Virginia Natural Gas	2022	Virginia Natural Gas	PUR-2022-00052	Cash Working Capital

Montana-Dakota Utilities

Cash Working Capital Leads/Lags

Line No.	Lead/Lag	Days
1	**Revenue Lag**	
2	Service Lag	15.21
3	Billing Lag	1.00
4	Collections Lag	33.77
5	Total Revenue Lag	49.98
6	**Expense Leads**	
7	Payroll and Withholdings	19.75
8	Payroll Taxes	19.13
9	Employee Benefits	13.06
10	Other O&M Expenses	41.55
11	Fuel and Purchased Power	5.24
12	Property Taxes	251.30
13	Public Service Regulation Fee	73.46
13	Consumer Counsel Fee	73.46
15	Electrical Energy License Tax	73.98
16	Wholesale Energy Transaction Tax	74.00
17	Ft. Peck Tribal Tax	377.33
18	Highway Use Tax	(148.50)
19	Electric Wind Generation Tax	180.83
20	Secretary of State Tax	8.16
21	Coal Conversion Tax	0.84
22	Delaware Franchise Fee Tax	106.18
23	Federal Income Taxes	38.00
24	State Income Taxes	38.00

25	Interest on Long-Term Debt	91.50
26	Short-Term Interest	30.26

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

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 North Dakota 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 Montana electric operations per books cost of service for the twelve months ended June 30, 2022 and the pro forma cost of service reflecting known and measurable adjustments that will occur by June 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 post retirement benefits regulatory asset and Cash Working Capital Adjustment in rate base. Furthermore, I will present proposed changes to Rate 58 – Fuel and Purchased Power Cost Tracking Adjustment and I will present the Rate 56 – Electric Tax Tracking Adjustment base tax to be established in conjunction with this filing.

Q. What statements, schedules, and exhibits are you sponsoring?

A. I am sponsoring Statements C through E, Statements G through K (excluding H-1), Part A of Statement O, and the revenue requirement presented in Exhibit No.___ (TRV-1). I am also sponsoring the interim Statements A through E, Statement G, Statement H, pages 1-4, Statements I through K and Statement O, 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 $10,499,674, which represents a 15.2 percent increase, based on pro forma June 2023

Q. How was the $10,499,674 revenue requirement derived?

A. The Company has developed the pro forma revenue requirement based on adjustments to the sales revenues, Operation & Maintenance (O&M) expenses, other operating expenses, taxes, and the June 30, 2023 rate base. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

<u>Revenue Requirement</u>

Q. What were the results of Montana electric operations for June 30, 2022?

A. Rule 38.5.175, pages 1 and 2 show the per books income statement and rate base for the Montana electric operations for June 30,

2022. As shown on page 1, Montana electric operations had a return on rate base of 6.513 percent for the twelve months ended June 30, 2022.

Q. How was the per books cost of service allocated to Montana?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as 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 pro forma year ending June 30, 2023 test period. As stated by Ms. Kivisto, the revenue increase is largely driven by:

	Amount (in millions)
Rate Base	$2.3
O&M Expenses	2.0
Rate of Return	2.0
Property Taxes	2.0
Heskett Unit IV	1.4
Depreciation	0.7
Other	0.1
Net Increase	$10.5

The Heskett Unit IV addition is included in the rate base and represents approximately $1.4 million of the increase. Other plant additions, including the unamortized balance of the Lewis & Clark and Heskett coal units, represents another $2.3 million increase. Estimated Property Taxes are projected with an increase of approximately $2.0 million. Depreciation and amortization increases are a result of the updated Depreciation Study, the Lewis & Clark Unit I and Heskett Unit I & II amortization, and other additions to rate base. These increases are partially offset by the Lewis & Clark Unit I and Heskett Unit I & II plant closures.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses, and rate base were based on known and measurable changes occurring by June 30, 2023, conformed to past Commission practices, and are listed on pages 3 through 5 of Rule 38.5.175. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement or rule listed. All adjustments were calculated on a Montana specific basis as indicated on the statement or schedule detailing each adjustment.

Q. Would you describe the pro forma adjustments to the income statement and rate base?

A. Yes. The adjustments to the income statement are summarized in Rule 38.5.175, page 3 and 4 and consist of adjustments to revenue, operation and maintenance expenses, depreciation expense, taxes other, and current and deferred income taxes. The adjustments to rate base are summarized on page 5 and include plant, accumulated reserve for depreciation, and associated additions and deductions.

<u>Pro Forma Income Statement</u>

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 38.5.164, Statement H.

Adjustment No. 1 is an increase of $1,330,662 in retail sales revenue that is based on pro forma volumes and current rates reflecting the pro forma fuel and purchased power expense. Pro forma retail sales revenue includes Rate 56 - Electric Tax Tracking Adjustment revenues (TTA) based on the rates effective January 1, 2022 as authorized in Docket No. 2021.10.122. Pursuant to paragraph 3(b) of Rate 56, a base tax amount shall be updated in a general rate case and will be expressed as a percentage to be applied to the basic service charge, energy charge, and demand charge revenue. Therefore, the total revenue shown in this filing includes Montana direct ad valorem taxes of $4,705,264, based on the current Electric Tax Tracking Adjustment Rate 56 tariff. At the same time, the inclusion of TTA revenue is necessary to properly reflect the pro forma level of late payment revenue in Adjustment No. 3 below as well as the uncollectible accounts expense (Adjustment No. 13) and the Montana Consumer Counsel/Public Service Commission revenue taxes (Adjustment No. 26).

Adjustment No. 2 decreases revenue by $532,951 to reflect the elimination of sales for resale as these revenues are passed back to customers through the Fuel & Purchased Power Adjustment.

On page 4 of Statement H, Adjustment No. 3 is comprised of several adjustments to miscellaneous operating revenues. Several adjustments to miscellaneous operating revenue were based on the pro forma three year average. The pro forma late payment revenue reflects a three-year average of late payment revenue to retail sales revenue. Montana-Dakota is using a pro forma based three-year average of KVAR penalty revenue as a representative level of KVAR penalty revenue. Gains and losses reflect an amortization on sale of plant over a five-year period.

The decrease in transmission service revenue of $463,821 is largely related to the movement of an asset to the MISO jurisdiction. The corresponding plant investment and related expenses were also moved the MISO jurisdiction resulting in a minimal net impact to the revenue requirement. The Company is proposing to recover transmission service revenue in a manner consistent with fuel and purchased power expenses through the Fuel & Purchased Power Cost Tracking Adjustment as shown in Statement G, Adjustment No. 4. This proposal is described later in my testimony and in the testimony of Mr. Neigum.

Q. **What adjustments were made to operation and maintenance expenses?**

A. The adjustments to operation and maintenance expenses are summarized in Rule 38.5.156, Statement G, pages 1 through 4 and contained in Rule 38.5.157, Statement G.

Q. Have you updated the fuel and purchased power costs?

A. Yes. Adjustment No. 4 on page 3, Rule 38.5.157 of Statement G reflects a decrease of $120,611 for fuel and purchased power costs. This is based on the pro forma generation and power purchase requirements and has been updated to reflect projected cost assumptions and purchased power prices, including the recent purchase power agreement. The reduction in Adjustment No. 4 is also inclusive of a slight increase in of regional transmission organization (RTO) transmission service expenses of $288,551 based on the current MISO and Southwest Power Pool (SPP) tariff rates. Montana-Dakota is proposing to recover RTO transmission service expenses through the fuel and purchased power cost tracking adjustment. As mentioned previously in my testimony, Statement H, Adjustment No. 3 reflects the pro forma adjustments to transmission service revenue in other operating revenues. Currently, RTO transmission service expenses and transmission service revenue are components of base rates while MISO and SPP energy market charges are recovered through the fuel and purchased power cost adjustment. As discussed in the testimony of Mr. Neigum, Montana-Dakota's participation in the RTOs has provided significant benefits in terms of reduced energy costs. The Company's proposal will provide a more appropriate relationship between the RTO transmission service charges incurred with the costs and benefits associated with participation in the energy markets of the same RTOs. Therefore, the Company's proposal reflects the net transmission charges incurred by the Company in its Rate 35 and 58 revisions as shown on Workpaper Statement G, page 4.

Q. Would you describe the development of the labor and benefits expense?

A. Yes. Labor expense is shown as Adjustment No. 5, in Rule 38.5.157, Statement G, page 4, with actual labor expense for the twelve months ended June 30, 2022 used as the starting point.

The Pro Forma Adjusted June 2022 labor value excludes costs associated with the Lewis & Clark Unit I and Heskett Units I & II and includes additional positions and restructuring as defined on page 5 and 6. Furthermore, the pro forma labor was developed by applying the percentage increase in total Company labor costs to the adjusted June 30, 2022 Montana labor expense. Pro forma total Company labor costs were based on an increase of 5.02 percent in 2023 and includes a 2022 mid-year salary increase of 1.05 percent, and 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, of which both are effective in 2023. Incentive compensation has been adjusted to reflect the targeted incentive level of 11.65%, as compared to straight time and vacation.

Montana-Dakota has hired approximately 14 full time employees to its Customer Experience Team as replacements for annualized employee turnover in 2022. Furthermore, as described in detail by Mr. Anderson, an Outage Management System will be implemented which will require additional employees. These replacement or new positions and the labor expenses associated are further defined in pages 5 through 6.

Benefits are shown on page 7 of Statement G, Adjustment No. 6, and reflects an overall increase of $228,013 with additional support provided on page 8. Benefits expense consists of medical/dental insurance, pension, post-retirement, 401K, workers compensation, and other benefits. Each of these items was adjusted individually. Medical/dental expense is increasing 14.00 percent per year based on premiums to be in effect for 2023. The pension expense increased $160,991 due to a combination of higher costs and lower expected returns on the assets based on the 2023 Actuarial Estimate. The post-retirement expense decreased 3.80 percent and is also based on the 2023 Actuarial Estimate. The pro forma 401K, workers compensation, and other benefits expense reflected the straight time labor increase of 5.02 percent to remain in line with the overall average increase in straight time labor. Page 8 represents the additional benefits associated with the new and replacement positions referenced above.

Q. Would you describe the other adjustments made to O&M expense?

A. Yes. The subcontract labor expense shown on Statement G, Adjustment No. 7 is based on the Pro Forma Adjusted value, adjusted to reflect Heskett Units I & II and Lewis & Clark Unit I retirements, increase in the maintenance agreements for Thunder Spirit I & II and increase in line locating and line clearance tree trimming.

Big Stone and Coyote expenses shown on Statement G, page 10 as Adjustment No. 8 reflects the expenses associated with these generating stations for the year ending June 30, 2023. The adjustment reflects the expected costs of operation and a normalized outage scheduled.

Materials expense, shown on Statement G, Adjustment No. 9, page 11 reflects the Pro Forma Adjusted to exclude the retirement of Heskett

Units I & II and Lewis & Clark Unit I. Furthermore, based on information provided by the Company's major material supplier, an increase of 23 percent for transmission material and 27 percent for distribution was added to the pro forma period.

Adjustment No. 10, shown on page 12 for vehicles and work equipment, reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers, and excavators, including the cost of fuel, insurance, maintenance, and depreciation expense. The depreciation expense on these items is charged to a clearing account (rather than to depreciation expense), where it is then recorded in O&M expense or capitalized as part of a project as the vehicle or work equipment is used. The Pro Forma Adjustment is based on pro forma plant and proposed depreciation rates and reflects an increase in projected fuel expenses based on U.S Energy Information Administration Short-Term Energy Outlook.

Adjustment No. 11 for company consumption, on page 13 of Statement G, is the expense for general utilities, electric, and natural gas consumption in Company buildings and is expected to increase $5,625. The general utilities and electric components represent an increase of

0.72% to reflect volumes at current rates. The natural gas component is based on an increase of 29.08% to reflect weather normalized volumes; which is partially offset by a lower forecasted per unit cost of natural gas. General utilities, electric and natural gas exclude Lewis and Clark Unit I and Heskett Unit I & II.

Adjustment No. 12 for postage expense is shown on page 15 of Statement G. The pro forma adjustment reflects the 8.08 percent increase based on the weighted average postage increase that is then partially offset by additional postage savings for the year. The additional postage savings are calculated by considering the number of customers receiving their monthly billing via electronic format as of the June 2022, reflecting increases in customer participation during the preceding twelve months.

Adjustment No. 13 for uncollectible accounts expense shown on page 16 of Statement G, is based on the June 30, 2022 write-offs to sales revenue. This ratio was then applied to the pro forma sales revenues, which results in a slight increase in uncollectible accounts expense.

Adjustment No. 14 for Advertising expense is shown on page 17 of Statement G and reflects a decrease of $12,261. Promotional advertising expenses have been eliminated from the pro forma period and informational and institutional advertising are adjusted to exclude advertising that is not applicable to Montana electric operations.

Adjustment No. 15 for insurance expense, shown on page 18 of Statement G, reflects an increase of $218,827. This increase is reflective of an anticipated 10.00 percent increase over current premiums, and increases to accommodate for the addition of Heskett Unit IV.

Adjustment No. 16, shown on page 19 for software maintenance expense, is an increase of $90,593 and is based on pro forma estimated levels. The costs associated with the Pro Forma timeframe are based on the five-year average increase of expense and reflect expenses related to a variety of areas including those mandated cybersecurity needs.

Adjustment No. 17, for industry dues, is shown on page 20, reflects a decrease of $7,608. The industry dues are directly assigned or allocated to Montana and are appropriately included pro forma expense. In compliance with a previous Order, 40.00 percent of dues to local Chambers of Commerce have been excluded.

Annual Easements are shown on page 21 of Statement G as Adjustment No. 18. This adjustment reflects Diamond Willow easements at the per books level, and the Thunder Spirit and Cedar Hills easements at the applicable contractual annual escalation.

Regulatory commission expense as shown on page 22 of Statement G, Adjustment No. 19 and reflects the expenses to be incurred in this filing amortized over a three-year period, a three-year period of ongoing regulatory commission expense, and the expenses related to the depreciation studies amortized over five years.

Those areas that were temporarily reduced due to the Covid-19 pandemic are shown on page 23 of Statement G, Adjustment No. 20. Furthermore, they also reflect adjustments to exclude Heskett Unit I & II and Lewis & Clark Unit I. 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 adjusted using an average of the years ending June 30, 2018 through 2020 and June 30, 2022 applied to the Pro Forma calculation.

The O&M expenses adjusted individually above represent approximately 97.7 percent of total Montana electric O&M expenses, as shown on Statement G, pages 1 and 2. The remaining O&M expenses, which make up approximately 2.3 percent of other O&M expenses, were adjusted to exclude those costs associated with Lewis & Clark Unit I and Heskett Units I & II.

Q. Would you describe the calculation of depreciation expense?

A. The adjustments to depreciation expense are summarized in Rule 38.5.165, Statement I, page 1.

Adjustment No. 22 is comprised of three components. First, the adjustment shows the annual depreciation expense based on the average pro forma level of plant in service including the addition of Heskett IV and the Diamond Willow Wind repower. Concentric Advisors, ULC consultants prepared a depreciation study, at the Company's request, for electric assets based on the plant balances on December 31, 2020, with an update to include the investment in the Diamond Willow Wind repower. The electric study is supported in the testimony of Mr. Kennedy. The common depreciation rates proposed in this filing are consistent with depreciation rates approved in the last electric rate case in Docket No. 2018.09.060. The depreciation rates are shown on Statement I, pages 3 through 6. The total pro forma change to depreciation expense is $807,107.

Adjustment No. 22 also reflects the impacts of the latest decommissioning studies and related pro forma decommissioning balances. Montana-Dakota has updated the decommissioning study for all generating units except those jointly owned for this filing. The updated studies reflect the costs to comply with the most recent decommissioning requirements and salvage estimates. The current estimate for Montana's share of the decommissioning costs indicates that the unamortized balance, exclusive of Lewis & Clark Unit I and Heskett Units I & II, as of June 30, 2022, requires an annual amortization of $314,748. This amortization is $263,638 short of the current annual amortization. This, combined with the amortization of the Heskett and Lewis & Clark regulatory asset discussed in the testimony of Mr. Jacobson, as well as the elimination of the previously retired power plant amortization and the excess deferred tax amortization, creates a pro forma adjustment of $1,321,467.

Total depreciation expense and the pro forma depreciation adjustment is shown on page 2 of Schedule I, Adjustment No. 22.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are summarized in Rule 38.5.173, Statement K, page 1 and Rule 38.5.174, Statement K, pages 1 through 4.

Adjustment No. 23 reflects Montana ad valorem taxes, allocated ad valorem taxes, and tribal valorem taxes. The Montana direct ad valorem taxes were based on the 10.12 percent increase which represents the three-year historical average ad valorem tax increases. As previously mentioned in my testimony, Montana-Dakota has included the pro forma Montana direct ad valorem tax increase in order to update the base tax percentage applicable under Rate 56 - Electric Tax Tracking Adjustment upon disposition of this rate case. The Company will file an update to Rate 56 in late 2022 with changes to be effective January 1, 2023; however, the base tax percentage is not allowed to be adjusted in that filing. Therefore, the revenue collected under the January 1, 2023 TTA rates will not be matched with the total tax expense until the base tax percentage is updated upon conclusion of the case.

Adjustment No. 23 also restates the allocated ad valorem taxes to reflect an increase of 5.60% increase which also represents the three-year average allocated ad valorem tax. Lastly, the tribal ad valorem taxes reflect pro forma increase based on the annualized first six months of 2022.

Adjustment No. 24 for payroll taxes were based on the ratio of payroll taxes to labor expense, excluding moving allowance and taxable meals, for twelve months ending June 30, 2022 applied to pro forma labor expense as shown on Statement K, page 2 and reflects an increase of $3,391.

Adjustment No. 25 for electric production taxes is summarized on page 4 of Statement K, Rule 38.5.174. Production taxes have been adjusted to reflect Pro Forma projected generation levels and applicable retail sales volumes.

Adjustment No. 26 for Montana Consumer Counsel Tax and Public Service Commission taxes based on applying the tax rate, effective October 1, 2022, to the pro forma revenue and miscellaneous revenue.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are summarized in Rule 38.5.169, Statement J, page 1.

Adjustment No. 27 is for interest expense and is based on the pro forma rate base and cost of debt. It is shown on Rule 38.5.169, Statement J, page 5. Interest is deductible for tax purposes and the interest expense is calculated on the pro forma rate base using the weighted cost of debt from Rule 38.5.146, Statement F, page 1.

Adjustment No. 28, shown on page 6, reflects the changes associated with book/tax depreciation differences and displays the projected changes due to the plant additions as well as existing plant in service as of June 30, 2022.

Adjustment No. 29 is the pro forma adjustments to current income taxes on operating revenues and expenses as shown on page 7.

Adjustment No. 30, shown on page 8, reflects the production tax credits (PTC) and is related to energy produced at the Company's wind generating facilities. The pro forma adjustment is based on a PTC rate of $0.026 per kWh and the generation from Thunder Spirit and the Diamond Willow Repower.

As discussed in the testimony of Mr. Geiger, the Diamond Willow Repower project was determined to be a benefit to customers based on the assumption that PTC's would be credited at 80% of the standard value. However, based on the changes allowed in the Inflation Reduction Act of 2022, the project is now eligible for full PTC credit and is considered to begin earning these credits on November 1, 2022.

Shown on page9, Adjustment No. 31 reflects an adjustment to the per books 2021 actual results to reflect the impact of the federal tax rate on current and deferred income taxes.

Adjustment No. 32, on page 9, is the change in plant related excess deferred income taxes.

<u>Rate Base</u>

Q. Would you describe the development of the rate base?

A. The pro forma rate base is based on the average rate base for the twelve months ending June 30, 2022. The pro forma adjustments to rate base are summarized in Rule 38.5.175, page 5.

Adjustment A shown in Rule 38.5.123, Statement C, pages 2 through 9 are the known and measurable plant additions that will be in service by June 30, 2023. The increase of $37,965,736 includes additions to production, transmission, distribution, general, and common plant.

Adjustment A also includes the addition of Heskett IV, a natural gas-fired, 88 MW, simple cycle combustion turbine. This project is discussed in more detail in the testimony of Mr. Geiger. Further benefits of this project are discussed in the testimony of Mr. Neigum.

The summarized plant additions are shown on page 10 of Rule 38.5.123 Statement C. Because Lewis & Clark Unit I and Heskett Units I & II are being retired, there are no capital additions related to these coal units, except for those associated with landfill closures. Page 16 specifically references the addition and associated depreciation, and taxes associated with Heskett Unit IV. This production investment is $15,570,254 and has been annualized to reflect the plant additions as if they were in service the entire year. The value of capacity attributable to this project, through the reduction of the capacity PPA from 90 MW to 30 MW, will flow to customers immediately as offsets to costs recovered through the fuel and purchased power cost adjustment upon commercial operation in Spring 2023. This project is discussed in more detail in the testimony of Mr. Geiger and Mr. Neigum. All related adjustments were also annualized, including the depreciation and insurance expense.

Adjustment B shown in Rule 38.5.133, Statement D, page 2 is the accumulated reserve for depreciation on plant additions, including the addition of Heskett IV, with the average pro forma plant levels.

Q. How were the working capital items derived?

A. The working capital adjustments are summarized in Rule 38.5.141, Statement E, page 1.

Detailed information for Adjustments C through O are shown on Rule 38.5.143, Statement E, pages 1 through 13. Materials and supplies, fuel stocks, and prepayments were restated to a thirteen-month average on pages 1, 2, and 3, reflecting actual balances through June 2022. Materials and supplies and fuel stocks project July 2022 through June 2023 based on the prior period actual results. The pro forma period for prepayments is based on expected insurance expenses.

Adjustment F, G, I, K, and N reflect the unamortized loss on debt, decommissioning of retired power plants, unamortized redemption of preferred stock cost, provision for injuries & damages, and accumulated investment tax credits. These adjustments were calculated using the balance as of June 30, 2022. The annual amortization is then added to calculate a June 30, 2023 balance and the averages are based on the resulting balances, as shown on Statement E, pages 4, 5, 7, 9, and 12 .

Adjustment J reflects the provision for pension & benefits and is found on page 8. The Company has consistently included pension & benefits as an asset or liability in rate base in conformance with Order 5856b in Docket No. D95.7.90. This adjustment was calculated using the balance as of June 30, 2022. The annual amortization is then added to calculate a June 30, 2023 balance and the average is based on the resulting balance.

Adjustment H, reflecting the regulatory asset associated with the retirement of Lewis & Clark Unit I and Heskett Units I & II, is shown on Rule 38.5.143, of Statement E, page 6. This regulatory asset is reflective of the deferred accounting treatment that was approved in Docket No. 2019.11.086. Montana-Dakota is now requesting recovery of these deferred costs over a 10-year period. The annual amortization is outlined on Rule 38.5.165, of Statement E, page 6 and is based on a 10-year amortization of the deferred costs. Please see the testimony of Mr. Jacobson more detail on this adjustment.

Adjustment L shown on page 10 is the provision for post retirement and the associated deferred income taxes. This is more fully discussed below.

Adjustment M is the cash working capital adjustment. In the Stipulation and Agreement for Docket No. 2018.09.060, Montana-Dakota agreed that in its next rate case, it would perform a lead-lag study and utilize a cash working capital calculation. The lead-lag study is fully supported in the testimony of Mr. Adams. However, the calculation of the cash working capital adjustment was performed by applying the expense lead and revenue lag days from the lead-lag study to the applicable pro forma adjustment. This resulted in a decrease in the rate base of $940,176 and a reduction in the revenue requirement of approximately $88,000.

Adjustment O is the customer advances for construction reflecting a thirteen-month average balance with actuals through June 2022 as shown in Rule 38.5.143 Statement E, page 13.

Q. Would you describe how the accumulated deferred income tax balances were developed?

A. The accumulated deferred income tax balances are summarized on page 10 of Statement J, adjustment P. The pro forma balances were derived by adding the changes to the deferred income taxes to the Pro Forma Adjusted balances and calculating the average balance.

Finally, in Docket No. 2018.09.060, Montana-Dakota agreed that in its next case, it would provide a clear itemized breakout of its plant related Excess Accumulated Deferred Income Tax (EADIT) balances. This breakout is provided in Rule 38.5.169, Statement J, page 14

Q. What does Rule 38.5.190, Statement O show?

A. The charts and graphs contained in Rule 38.5.190, Statement O, Part A are the pictorial exhibits required by Commission rules.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRV-1)?

A. Exhibit No.____(TRV-1), which is identical to Rule 38.5.175, page 8 shows the calculation of the revenue deficiency of $10,499,674 to be collected in based on the Company's proposal. The revenue requirement is based on the pro forma operating income, rate base, and the overall rate of return of 7.525 percent from Rule 38.5.146, page 1 and supported by Ms. Nygard.

<u>Post Retirement</u>

Q. Montana-Dakota has proposed to include the post retirement regulatory asset in rate base. Will you explain why the Company has decided to include this regulatory asset in rate base at this time?

A. Yes. As discussed in the testimony of Ms. Kivisto, the cash contributions made by the Company have significantly exceeded the post retirement 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.

Due to post retirement annual expenses being reduced as they are recovered through the revenue requirement, this case reflects a negative cost of $300,000. This is a savings to customers and largely offsets the inclusion of the post retirement net assets.

Montana-Dakota considers the benefits and the circumstances surrounding the creation of the post retirement prepaid asset or liability similar to the pension prepaid asset or liability. 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 2010 through December 2021. As shown, Montana-Dakota has made cash contributions in the amount of $5.6 million for the total company. In addition, the Company has returned another $5.5 million in total to customers through the revenue requirement.

MONTANA-DAKOTA UTILITIES CO.
POST RETIREMENT BALANCE SUMMARY
ENDING DECEMBER 31, 2021

	Cash Contributions	Post Ret Expense	Other 1/	MDU Res Reorg Adj	Ending Balance
2010					($2,201,946)
Activity-2011	$1,569,959	$1,554,615	($511,512)		(2,698,114)
Activity-2012	3,317,515	3,382,307	(425,555)		(3,188,462)
Activity-2013	300,901	45,369	(334,687)		(3,267,617)
Activity-2014	102,979	(401,274)	(301,947)		(3,065,310)
Activity-2015	35,923	76,715	32,690		(3,073,412)
Activity-2016	35,908	(599,539)	(117,747)		(2,555,712)
Activity-2017	91,438	(1,568,437)	(113,985)		(1,009,822)
Activity-2018	69,576	(1,851,738)	(92,402)		819,091
Activity-2019	6,632	(1,858,990)	(52,134)	(409,553)	2,223,026
Activity-2020	28,728	(2,017,177)	4,011,021		8,279,952
Activity-2021	19,525	(2,225,984)			10,525,461
	$5,579,084	($5,464,133)			

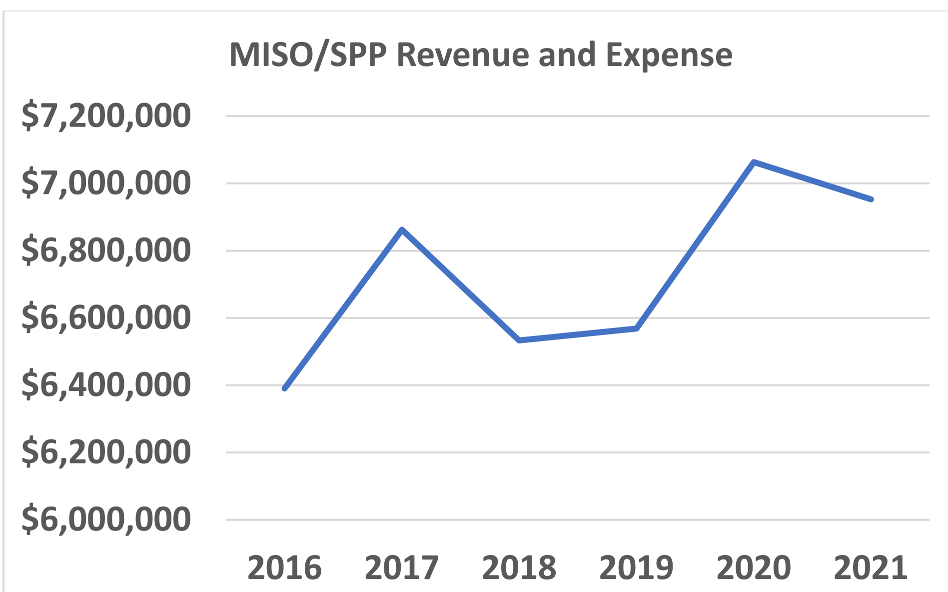
1/ Primarily Medicare Part D.

Electric Fuel and Purchased Power Cost Tracking Adjustment

Q. Would you describe the adjustments to the electric fuel and power adjustment cost tracking adjustment proposed in this filing?

A. Yes. Montana-Dakota is proposing to incorporate changes in the fuel and purchased power cost tracking adjustment.

First, as discussed earlier, the Company is proposing to include all expenses associated with the MISO and SPP Regional Transmission Organizations (RTO) markets in the fuel and purchased power cost tracking adjustment. The testimony of Mr. Neigum further describes the connectedness of the energy and transmission markets within the RTOs and the benefits that the transmission market affords the energy markets. In addition, including the MISO and SPP transmission revenue and expenses in the fuel and purchased power cost tracking adjustment will allow the Company to capture the increases as well as return the decreases to the customer, on a monthly basis. The graph below represents the net expense for MISO and SPP, allocated to Montana customers, for 2016 through 2021.



Mr. Neigum further explains why the Company is proposing to treat the energy and transmission charges for the RTO's within the fuel and purchased power cost tracking adjustment.

This proposed changed would reflect the recovery of transmission service expense and revenue through the fuel and purchased power cost tracking adjustment. The following table reflects the per unit impact as a result of the proposed change:

	Primary	Secondary	Contract
With Transmission	$0.02714	$0.02900	$0.02785
Excluding Transmission	0.02368	0.02436	0.02370
Change	$0.00346	$0.00464	$0.00415

Montana-Dakota's proposal shifts the recovery of transmission service expense and revenue from base rates to the fuel and purchased power cost tracking adjustment in a manner consistent with other components of the existing fuel and purchased power cost tracking adjustment.

Lastly, Montana-Dakota proposes to remove Subsection 3 c and d in Rate 58 which require the inclusion of the total Montana-Dakota sales by month and jurisdiction with annual totals. Montana-Dakota proposes that, due to the voluminous nature of the information (filing made on June 15, 2022 in Docket No. 2022.06.070 was 131 pages), the requirement should be eliminated. The Company proposes to provide this information upon request.

Exhibit No. ___(TRV-3) is the proposed Rate 58 tariff, also included in Appendix B.

Interim Revenue Requirement

Q. Is Montana-Dakota seeking an interim increase in this case?

A. Yes it is. As stated by Ms. Kivisto, Montana-Dakota is seeking interim rate relief in this case pursuant to the Commission's rules regarding interim rate increase requests in general rate proceedings.

Q. What amount of interim rate relief is the Company seeking?

A. The Company has identified an interim revenue requirement, presented in Exhibit No.___(TRV-2) of $1,716,219 and Statement A of the Interim Application based on the pro forma 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 Docket No. 2018.09.060;

- The investment associated with Heskett Unit IV and the associated depreciation was excluded;
- The Return on Equity (ROE) was modified to reflect the 9.25 percent determined in Docket No. 2015.06.051;
- The post retirement regulatory assets and cash working capital adjustments were excluded;
- The power plant decommissioning reverted back to current levels;
- Regulatory Commission Expense was updated to exclude the current case expenses;
- The Direct Ad Valorem taxes and associated revenue were excluded; and
- The annualized amortization of the Lewis & Clark Unit I and Heskett Units I & II regulatory asset was removed.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$69,204,490	**$10,499,674**		$79,704,164
Sales for Resale	0			0
Other	5,820,094			5,820,094
Total Revenues	75,024,584	10,499,674		$85,524,258
Operating Expenses				
Operation and Maintenance				
Fuel & Purchased Power	17,825,591			17,825,591
Other O&M	28,283,755			28,283,755
Total O&M	46,109,346			46,109,346
Depreciation	14,600,632			14,600,632
Taxes Other Than Income	7,617,217	36,539	2/	7,653,756
Current Income Taxes	(5,999,406)	2,755,209	2/	(3,244,197)
Deferred Income Taxes	1,818,274			1,818,274
Total Expenses	64,146,063	2,791,748		66,937,811
Operating Income	$10,878,521	$7,707,926		$18,586,447
Rate Base	$246,995,975			$246,995,975
Rate of Return	**4.404%**			**7.525%**

1/ See Rule 38.5.175, page 6 and 7.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.048% and PSC tax of 0.300%.

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN - INTERIM
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$64,499,226	**$1,716,219**		$66,215,445
Sales for Resale	0			0
Other	5,815,624			5,815,624
Total Revenues	70,314,850	1,716,219		$72,031,069
Operating Expenses				
Operation and Maintenance				
Fuel & Purchased Power	17,825,591			17,825,591
Other O&M	27,982,027			27,982,027
Total O&M	45,807,618			45,807,618
Depreciation	11,806,799			11,806,799
Taxes Other Than Income	1,425,025	5,972	2/	1,430,997
Current Income Taxes	(4,888,091)	450,352	2/	(4,437,739)
Deferred Income Taxes	2,055,027			2,055,027
Total Expenses	56,206,378	456,324		56,662,702
Operating Income	$14,108,472	$1,259,895		$15,368,367
Rate Base	$222,859,157			$222,859,157
Rate of Return	**6.331%**			**6.896%**

1/ See Rule 38.5.175, page 6 and 7.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.048% and PSC tax of 0.300%.

Exhibit No.__(TRV-3)

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

1. APPLICABILITY:

This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (c) amortization of the Unreflected Fuel Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 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 tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:

Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs by month by source, with annual totals and;

b. Generation and purchases (Mwh) by month by supply source, with annual totals.

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.714¢ per Kwh for primary service and 2.900¢ per Kwh for secondary service as established in the most recent general rate case.

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 Montana and to the primary and secondary customer classes:

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

   2. The cost of electric transmission delivery services linked to the utility's load serving obligation and associated with participation in regional transmission organizations as recorded in Account Nos. 560, 561, 565 and 928 offset by corresponding revenues received from regional transmission organizations as recorded in Account No. 456.

   3. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 4(c) multiplied by ninety (90) percent.

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected 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.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

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

(1) Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power as specified in Subsection 4.

(2) Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.

(3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in the Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

(1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. PUBLIC SERVICE COMMISSION & MONTANA CONSUMER COUNSEL TAXES:
The over or under recovered balance of Public Service Commission and Montana Consumer Counsel taxes shall be updated each year to be recovered with the amortization of the Unreflected Fuel Cost Account.

8. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

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

9. FUEL AND POWER COST ADJUSTMENT:

	Primary	Secondary
Base Fuel	2.714¢	2.900¢
Fuel and Power Cost Adjustment		
Total FPPA per Kwh		

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.11.___

Direct Testimony
of
Travis R. Jacobson

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

A. Yes. My name is Travis R. Jacobson, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. **Would you please describe your duties as Director of Regulatory Affairs?**

A. I am responsible for the development and implementation of Company objectives and policies with respect to rate structure, pricing policies, 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 Minot State University with a Bachelor of Science degree in accounting and I am a Certified Public Accountant (CPA). In

June 2019, I completed the Utility Executive Course at the University of Idaho in Moscow, Idaho. I started my career with Montana-Dakota in 1999 as a financial analyst in the Financial Reporting area and during my tenure with the Company have held positions of increasing responsibility, including Supervisor, Financial Reporting & Planning and Manager, Financial Reporting & Planning and Manager, Regulatory Affairs before attaining my current position.

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

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of North Dakota and Wyoming, and the Public Utilities Commissions of Minnesota and South Dakota.

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

A. The purpose of my testimony is to present the analysis of savings resulting from the retirement of the coal generating facilities, specifically Lewis & Clark Unit I and Heskett Units I and II. In addition, I will provide support for the Company's proposed treatment of the regulatory asset associated with the accelerated closure of the same units.

<u>2019 Integrated Resource Plan – Retirement Analysis</u>

Q. The 2019 Integrated Resource Plan or IRP included an analysis indicating closing the previously mentioned coal-fired generating facilities would result in a net savings to customers. Please discuss the analysis performed in the IRP.

A. On February 19, 2019, Montana-Dakota announced the Company's decision to retire the Lewis & Clark I, Heskett I and Heskett II coal-fired generators at the end of 2020 and 2021, respectively.

As detailed in Exhibit No. ___(TRJ-1)[1], Montana-Dakota undertook an in-depth review of the age and condition, economic competitiveness and future environmental compliance costs for the Lewis & Clark I, Heskett I and Heskett II generators as part of the 2019 IRP process. This review indicated that these generating units were no longer economically competitive in the MISO market and that to remain economically viable, unobtainable reductions in operating & maintenance expenses (O&M) would be required. For example, O&M expenses would need to be eliminated entirely for all three units while Heskett I and Heskett II would require an elimination of O&M expenses plus a reduction in coal costs. Based on a comparison of actual fuel plus variable O&M expenses for calendar year 2018, Heskett I, Heskett II and Lewis & Clark I were the highest cost units in Montana-Dakota's generation portfolio with costs on a dollar per MWh generated basis 1.4 to over 2 times Montana-Dakota's 2018 average MISO energy market purchase price of $25.85 per MWh.

Finally, an estimated revenue requirement, on *a total integrated electric system basis*, comparing the annual cost of running the three units in 2023 was compared to the cost of retiring Lewis & Clark I at the end of 2020 and Heskett I and II at the end of 2021. This analysis included all

[1] 2019 IRP, Volume IV, Attachment I.

post retirement costs and the cost of replacing the output of the retired plants with market energy purchases and the addition of a new simple cycle combustion turbine (Heskett IV). The post retirement costs included the amortization of employee retention benefit costs deemed necessary to keep the units running through the retirement dates, a 15-year amortization of the remaining net book values existing at the retirement dates and decommissioning costs. This analysis showed an annual savings of approximately $20 million on an integrated system basis assuming the units were retired and replaced.

Subsequent to the February 19, 2019, the Company determined that a March 31 retirement date would be better to avoid the extreme weather conditions normally experienced in January, February and early March. Lewis & Clark ceased operations in March 2021 and the Heskett units were retired in February 2022 due to high-cost maintenance issues that prevented the units from operating until the March 31 date.

<u>Deferred Accounting</u>

Q. Did the retirement announcement of the coal generating units require special accounting treatment?

A. Yes. Montana-Dakota continued to record depreciation expense based on the authorized depreciation rates, which are matched to the authorized revenue, as approved in Docket No. 2018.09.060. However, the authorized depreciation rates would not provide a net plant balance of $0 upon retirement; therefore, pursuant to GAAP accounting rules the

Company must accelerate the depreciation expense to achieve a net plant balance of $0. The difference between the accelerated depreciation required under GAAP and the authorized depreciation as approved in Docket No. 2018.09.060 was deferred subject to approval by the Commission. On November 1, 2019, Montana-Dakota filed an Application (Commission) seeking authority for a deferred accounting treatment of the accelerated depreciation and other costs related to the retirement of Lewis & Clark I, Heskett I and Heskett II. In that Application, the Company identified Montana's share of the total net plant balances as of August 31, 2019, as shown in the table below:

	Heskett I & II	Lewis & Clark I	Total
Plant In Service	$28,244,862	$18,350,631	$46,595,493
Accumulated Reserve	20,798,530	9,960,308	30,758,838
Net Plant	$7,446,332	$8,390,323	$15,836,655

The acceleration of the above-mentioned book depreciation and the subsequent retirement of the generating units resulted in an acceleration of the recognition of excess deferred income taxes (EDITs) stemming from the Tax Cuts and Jobs Act of 2017 for both Heskett and Lewis & Clark. The amount recognized, in excess of that reflected in rates, through the closure dates of each plant provided an offset in the amount of ($1.3) million on a revenue requirement basis.

In addition, the Company was required to recognize a liability for exit and disposal cost obligations associated with the plant including employee retention benefit costs of $1.5 million. The total costs identified for deferral are shown in the table below:

	Million $
Accelerated Depreciation	$15.8
Excess Deferred Taxes	(1.3)
Employee Retention	1.5
Total Deferred Costs	$16.0

On July 18, 2020, the Commission issued an Order approving Montana-Dakota's Application.

The updated deferred balances, which were used in this electric rate case, are as follows:

	Million $
Accelerated Depreciation	$15.2
Excess Deferred Taxes	(1.3)
Employee Retention	1.3
Total Deferred Costs	$15.2

<u>Savings and Amortization</u>

Q. Will Montana-Dakota experience the net savings anticipated in the 2019 IRP?

A. Yes. Montana-Dakota will experience the 2023 net customer savings contemplated in the 2019 IRP. The retirement savings were twofold: 1) Fuel and Purchased Power (F&PP) savings; and 2) lower revenue requirement. These savings were partially offset by the revenue requirement associated with the new Heskett IV gas turbine and the amortization of the deferred costs over a 15-year period.

Q. Starting with F&PP, please compare the savings to those projected in the 2019 IRP.

A. Lewis & Clark's cost of generation, including variable O&M, was approximately $36/MW and Heskett units I & II were $55/MW and $43/MW, respectively.[2] The 2019 IRP assumptions expected that the energy generated from the coal units could be purchased at an estimated cost of $25/MW. The retirements would result in a capacity need as well and the cost of replacing the shortfall was estimated at $4/kW-month. Montana-Dakota entered into two power purchase agreements (PPA) with Minnkota Power Cooperative (Minnkota) for the purchase of capacity and energy. Both PPAs began June 1, 2021 and have staggered expirations on May 31, 2023 and May 31, 2026. The first PPA provides needed capacity to cover the period from the retirement of three coal units and the in-service date of a new gas turbine. The new gas turbine must be dispatchable in MISO by June 1, 2023 to be eligible to be used as a capacity resource. The second PPA provides additional capacity to cover a projected shortfall the Company is forecasting through May 31, 2026 along with energy purchases from June 1, 2021 to May 31, 2026. The terms of the agreements are confidential; however, they are favorable to the assumptions used in the IRP.

The net annual F&PP savings projected in the IRP were $8,830,000. The PPA's favorable terms will add an additional $3,998,000

[2] Exhibit No.__(TRJ-1), 2019 IRP, Volume 4, Attachment I, Page 12, Figure 11

of saving for an overall savings of approximately $12,828,000 for customers of which approximately 24% or $3.1 million would benefit Montana electric customers.

It is important to note that the savings began flowing back to customers upon the closure of the coal units through the monthly Fuel and Purchased Power Adjustment. Therefore, beginning April 2021, customer's monthly electric bills have been reflecting fuel savings.

Q. Regarding the revenue requirement savings, please compare the projected savings to those projected in the 2019 IRP.

A. The IRP contemplated a 2023 test period based on the assumption that the coal units would continue to operate beyond the 2021/2022 retirement dates discussed above. The revenue requirement included continued capital additions necessary to meet various environmental regulations and included annual increases in O&M that would be required to operate and maintain the coal units and maximize their reliability and availability.

At this time, given the highest inflationary environment experienced in the last 40 years, the savings contemplated in the IRP are likely quite conservative. Because the plants are no longer operating, there are no exact numbers that can be compared. However, the Company maintains that the $33.5 million, on an integrated system basis, remains an accurate reflection of the savings for costs not incurred as a result of the retirements. These costs would have been part of this electric rate filing, net of the new gas turbine and deferred asset amortization, and would have resulted in an increase in the revenue requirement from that requested.

Q. Next, will you compare the revenue requirement of the Heskett IV gas turbine?

A. Yes. The main driver in the revenue requirement of approximately $10.6 million for the Heskett IV gas turbine is the capital investment, which was estimated at $79.8 million. The current estimated cost of capital investment is $64.8 million, and Montana's share has been included in this electric case. This is roughly a $15 million dollar reduction. Updating the revenue requirement with the current capital investment results in a reduction in the revenue requirement of approximately $1.7 million on an integrated system basis. The reduction is due to lower capital investment as well as a reduction in the associated depreciation expense.

Q. Finally, will you now discuss the amortization of the deferred costs?

A. Yes. The 2019 IRP reflected the amortization of deferred costs on an integrated system basis of $8.8 million. This was based on a 15-year amortization and included a pretax rate of return on the unamortized balance of 9.13%. The rate of return was based on a 50/50 capital structure, 5.5% cost of debt and 9.65% cost of equity. The cost of equity was matched to the most recently approved cost of equity for North Dakota since approximately 70% of the balance is related to North

Dakota. Montana's share of the $8.8 million is approximately 24% or $2,116,000.

Q. Does the Company continue to propose a 15-year amortization of the deferred costs?

A. No. A 10-year amortization has been proposed in this rate case. The annual revenue requirement, inclusive of a return on the unamortized balance of plant related deferred costs, is approximately $2,086,000. As noted above, the 2019 IRP was calculated on an integrated system basis. Montana has prefunded the decommissioning costs; therefore, Montana's deferred balances are less than North Dakota or South Dakota on a relative basis. In addition, the 2019 IRP did not reflect an offsetting accumulated deferred income tax related to the deferred balances which results in a higher required amortization level. Lastly, as noted above, the deferred balances were approximately 4% less than expected.

Q. You mentioned that the amortization reflects a return on the unamortized plant related balance. Please explain why the Company has proposed that treatment.

A. As demonstrated, the closure of the aging coal units reduced the revenue requirement, which directly benefits Montana electric customers. The investment in plant would normally be included in rate base and a return on the investment would be included in the revenue requirement. If the plants had not been retired early, the revenue requirement would still reflect the costs and the savings would not be passed on to customers.

Further, Mr. James A. Heidell, testifying on behalf of the North Dakota Public Service Commission in Case Nos. PU-19-306 and PU-19-307 stated:

> Yes, the Company is requesting a fifteen year amortization of the remaining plant balances of the Three Coal Plants along with a return on the unamortized plant balances. Regardless of whether the Three Coal Plants are retired, MDU's request is for customers to pay off the net plant balances through either depreciation or amortization charges and provide the Company with an annual return on either the net plant balance or unamortized regulatory assets associated with the remaining plant balances. Depending on how the plant balances are recovered in the retirement or no retirement scenarios there may be differences in the timing of the recovery, but on a net present value basis the total cost should be the same. Specifically, in the analysis provided by the Company the revenue requirement associated with the coal plants staying on-line is based upon annual depreciation expense and return on rate base, and that annual amount decreases over time due to the declining rate base.

Mr. Joel F. Jeanson, also testifying on behalf of the North Dakota Public Service Commission in Case No. PU-19-317, responded as follows when asked if he agreed with the Company's proposed amortization and rate base treatment:

> Yes. The proposed 15-year amortization period for accelerated depreciation exceeds the expected useful life of the plants had they remained in service based on the 2014 Depreciation Study filed in Case PU-16-666. In that study, the probable retirement date for the Heskett Generating Station was 2028 and the probable retirement date for Lewis & Clark Generating Station was 2025. By extending the amortization period beyond the probable retirement dates used to establish depreciation rates, the new revenue requirement during those time periods (that is, through 2028 for Heskett and through 2025 for Lewis & Clark) will be less than revenue requirements based on the proposed amortization periods. Given the incremental revenue requirements associated with Heskett 4, I believe that extending the amortization of accelerated depreciation costs and decommissioning costs over 15 years is reasonable. In addition,

authorizing a return on the unamortized balance is reasonable as it relates to utility plant or related expenditures.

I also agree the shorter 5-year amortization period for employee related costs is reasonable and the unamortized balances should not earn a return.

Q. Will you summarize the savings, including the amortization?

A. Yes. The 2019 IRP contemplated an annual savings on an integrated system basis of $20.6 million. The F&PP savings provided an incremental $4.0 million and the lower than projected capital investment costs added another $1.7 million. In addition, the amortization was held to the same revenue requirement impact over a 10-year period instead of the 15-year period shown in the 2019 IRP.

The total integrated system savings is now expected to be $26.3 million annually of which Montana would benefit at approximately 24% or $6.3 million through the Company's decision to retire the aging coal units and build a new gas turbine.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No.__(TRJ-1)

Attachment I

RETIREMENT ANALYSIS

ATTACHMENT I

RETIREMENT ANALYSIS

The purpose of this Attachment I is to discuss the information and analysis underlying Montana-Dakota's decision to retire the Lewis & Clark 1, Heskett 1 and Heskett 2 coal-fired generators at the end of 2020 and 2021, respectively.

As discussed below, the decision to retire the coal-fired generators at the Lewis & Clark and Heskett sites was the age of the plants, low-cost and availability of natural gas, and low-cost power on the MISO market, as well as rising fuel costs and operating & maintenance expenses at Lewis & Clark 1, Heskett 1, and Heskett 2. The IRP EGEAS model was also used to further substantiate the economic savings to customers associated with the Resource Plan with and without the retired units.

<u>2018 Request for Proposal (2018 RFP)</u>

Montana-Dakota's 2015 and 2017 Integrated Resources Plans indicated that at the retirement of Heskett 1, Heskett 2, and Lewis & Clark 1; a natural gas-fired combined cycle generation unit was the best future resource for the Company.

Montana-Dakota issued the 2018 RFP in August of 2018 to support the replacement analysis for Heskett 1, Heskett 2 and Lewis & Clark 1 at their future retirement date. Bids from the 2018 RFP, coupled with (1) a lower natural gas forecast price, (2) lower MISO energy market forecast prices, (3) higher capital costs for the combined cycle generator, and (4) lower prices for wind, solar, and storage; indicated that the combined cycle generator was no longer the best future resource to meet its customers' requirements.

With the Company's decision to move away from a future combined cycle generation unit, significant analysis was done that led the Company to review the age and condition, economic competitiveness, and future environmental compliance costs for Heskett 1, Heskett 2, and Lewis & Clark 1.

<u>Unit Age and Condition</u>

Heskett 1 has a 25 MW net generation capacity. The unit is located near Mandan, ND, commenced commercial operation in 1954 and has been in service for 65 years.

Heskett 2 has a 73 MW net generation capacity. The unit is located near Mandan, ND, commenced commercial operation in 1963 and has been in service for 56 years.

Lewis & Clark 1 has a 52 MW net generation capacity. The unit is located near Sidney, MT, commenced commercial operation in 1958 and has been in service for 61 years.

All the units have been well maintained, have high availability factors, and are in compliance with all environmental requirements and operating permits. The units, however, have low net capacity factors because of a lack of economic competitiveness with other alternatives available to the Company, including the MISO energy market.

Figure 1 shows the unit availability factor and the percent of actual generation compared to potential generation referred to as net capacity factors for the last seven years.

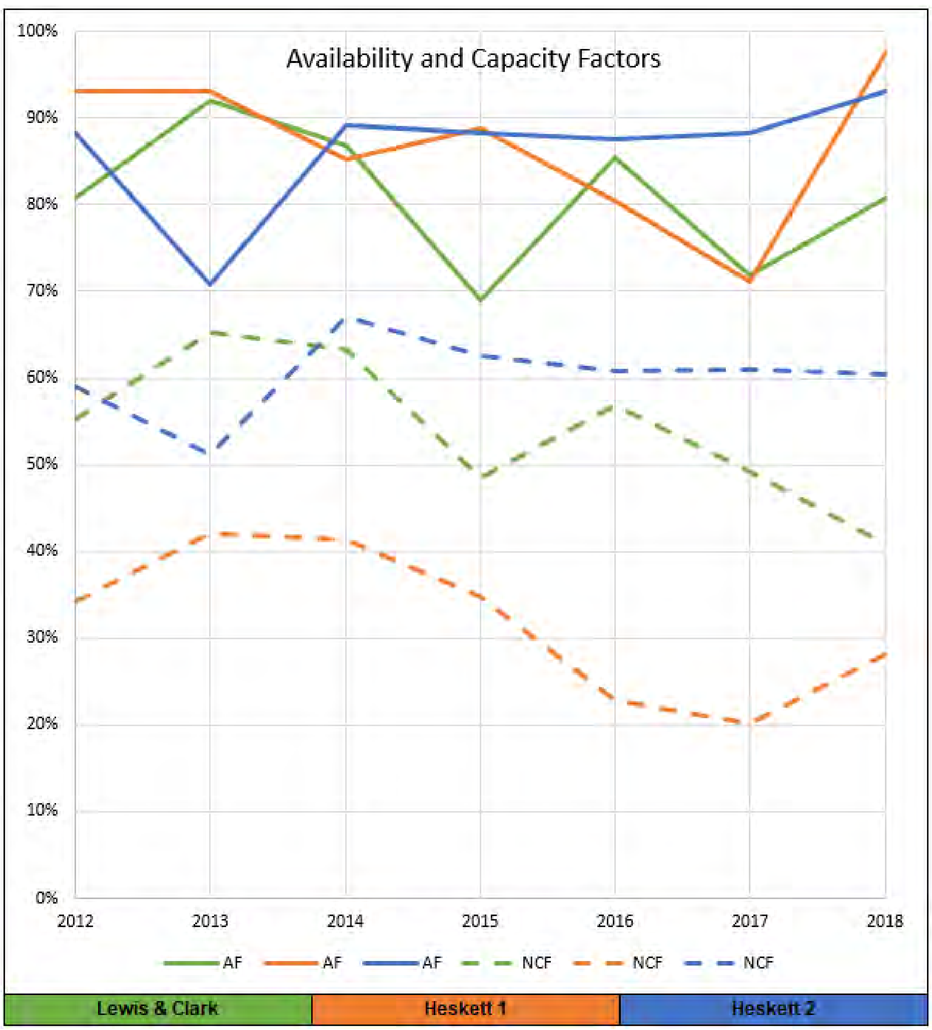


Figure 1 – Availability (AF) and Net Capacity Factor (NCF)

The difference in the relative magnitude of the net capacity factors between the three units is related to the level at which each unit has the physical capability or operating environment permit capability of reducing its output generation levels (otherwise called the "minimum output level" for each unit). If a unit is available to run, Montana-Dakota starts the unit and the generator will generate at its minimum output level in the market and any generation above the minimum output is economically dispatched against other generation available in the market.

Economic Competitiveness

As seen in Figure 1, the net capacity factors for the past seven years have been declining due to the lack of economic competitiveness with other generating resources within the MISO energy market. Heskett 2 has seen an increase due to a change in the plant operation and an increase in the plant's minimum output level.

Figure 2 shows the percent of hours that each generator runs at various output levels over the past seven years. Lewis & Clark 1 has a minimum output level of 34 MW and a maximum output level of 42 MW. Heskett 1 has a minimum output level of 7 MW and a maximum output level of 21 MW. Heskett 2 has a minimum output level of 50 MW and a maximum output level of 68 MW. As indicated in Figure 2, the generating units are being dispatched at their minimum output levels over 80% of the time. This trend, of the units being dispatched at their minimum output levels, has increased significantly in the last three years which is a direct indication that the units have lost their competitive dispatch position to other resources in the MISO energy market.

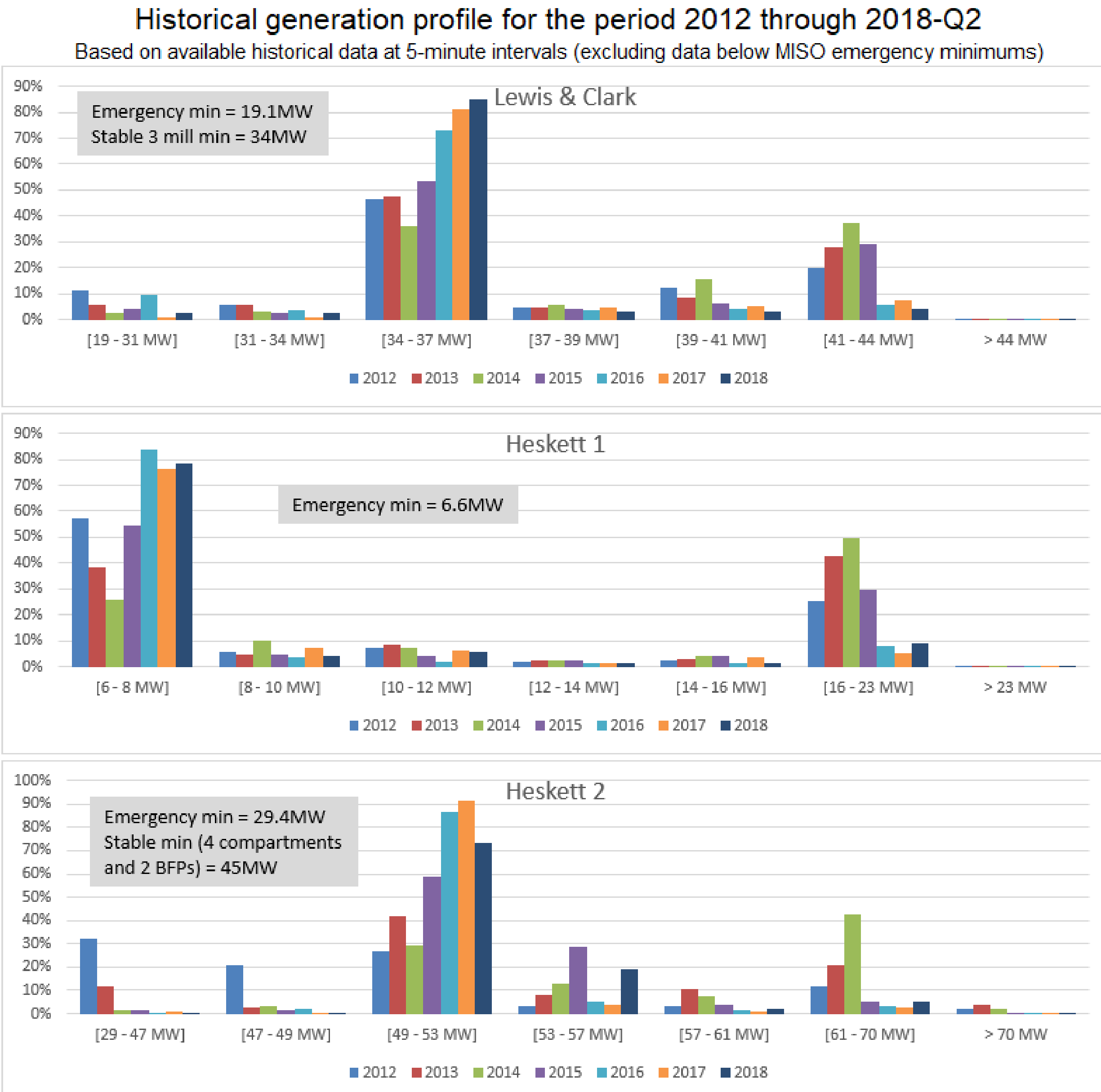


Figure 2 – Percent of Hours at Various Generation Output Levels

Montana-Dakota offers all its generation resources into the MISO energy market and buys all the energy to serve its customer load from the same MISO energy market. (See Attachment H – MISO and RTO Overview for a description of the MISO energy market.)

Economically dispatching the coal-fired units for any generation above their minimum output level saves the customer money as the Company can purchase energy from the MISO market at a lower cost than the variable operating cost to run the units. Montana-Dakota dispatches its coal-fired generation units at their minimum output levels, if the units are available, in order to meet the minimum annual volume provisions of its coal supply agreements. Minimum annual volume or take-or-pay provisions means that the Company must pay for a minimum amount of coal every year whether it is used.

Figure 3 shows the percentage of its energy requirements that Montana-Dakota has purchased from the MISO energy market to serve its customer load obligations, as well as the average purchase price paid for that energy. As shown in Figure 3, MISO energy market prices prior to 2009 were in the $60 per MWh range. However, MISO energy market prices have been very stable and low cost (about $21 to $26 per MWh) in recent years. This trend is expected to continue for the near future.

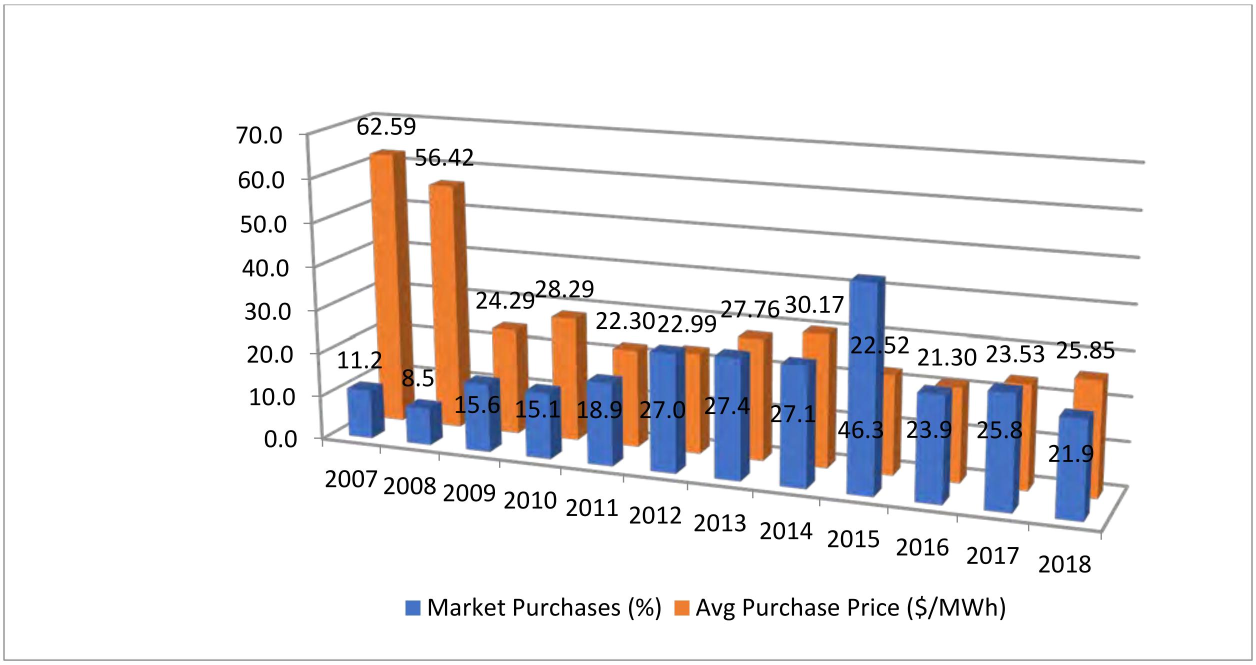


Figure 3 – MISO Market Energy Prices and Purchases

As part of the IRP Process, Montana-Dakota estimates future MISO market energy prices based on a three-year average of historic MISO pricing with a three percent escalation factor per year for future years. The three percent escalation factor is consistent with the escalation factor used for the IRP's natural gas price forecast which is developed by Montana-Dakota's Gas Supply Department using historic natural gas prices and trading hub index price forecasts. The forecasted prices of the MISO energy market and natural gas have been dropping in recent IRPs and illustrates the economic challenges that Montana-Dakota's older coal-fired generation fleet must compete against in the broader MISO energy market.

As seen in Figures 4 and 5, since 2013 the future forecasts for MISO energy and natural gas prices have been lower in each of the IRPs. These values affect the forecasted dispatch and overall economic competitiveness of Montana-Dakota's generation plants in the IRP model.

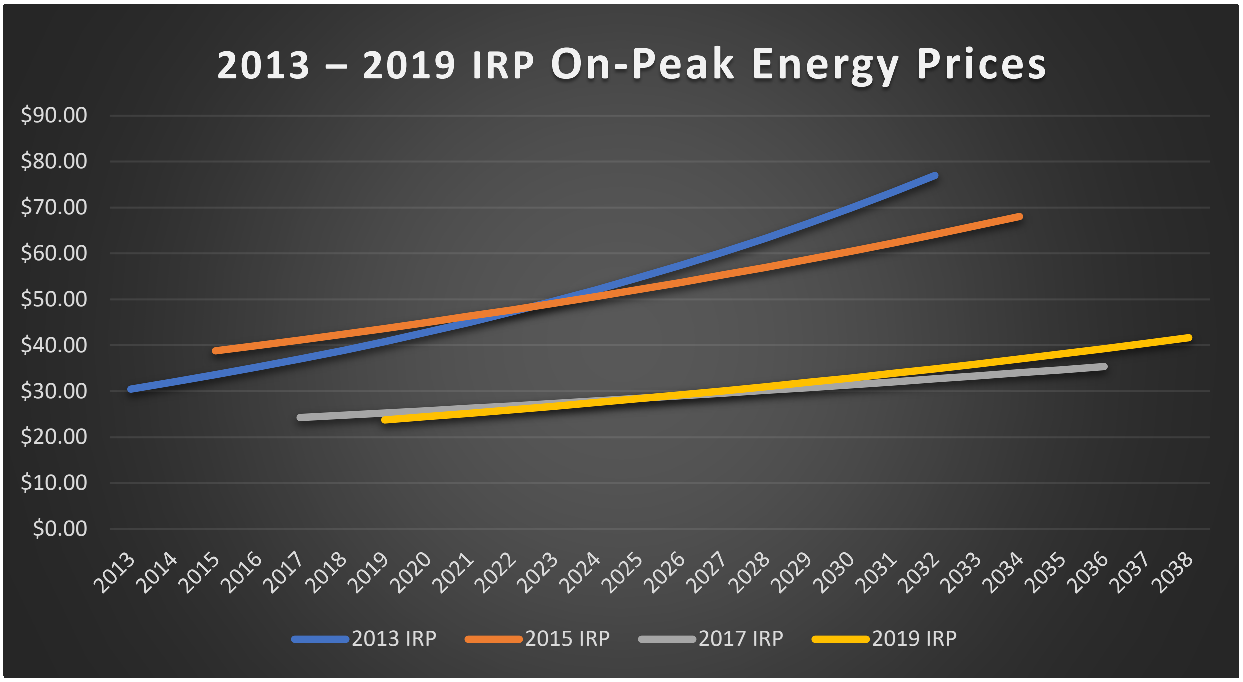


Figure 4 – MISO Market Energy Forecast Prices (2013 – 2019 IRPs)

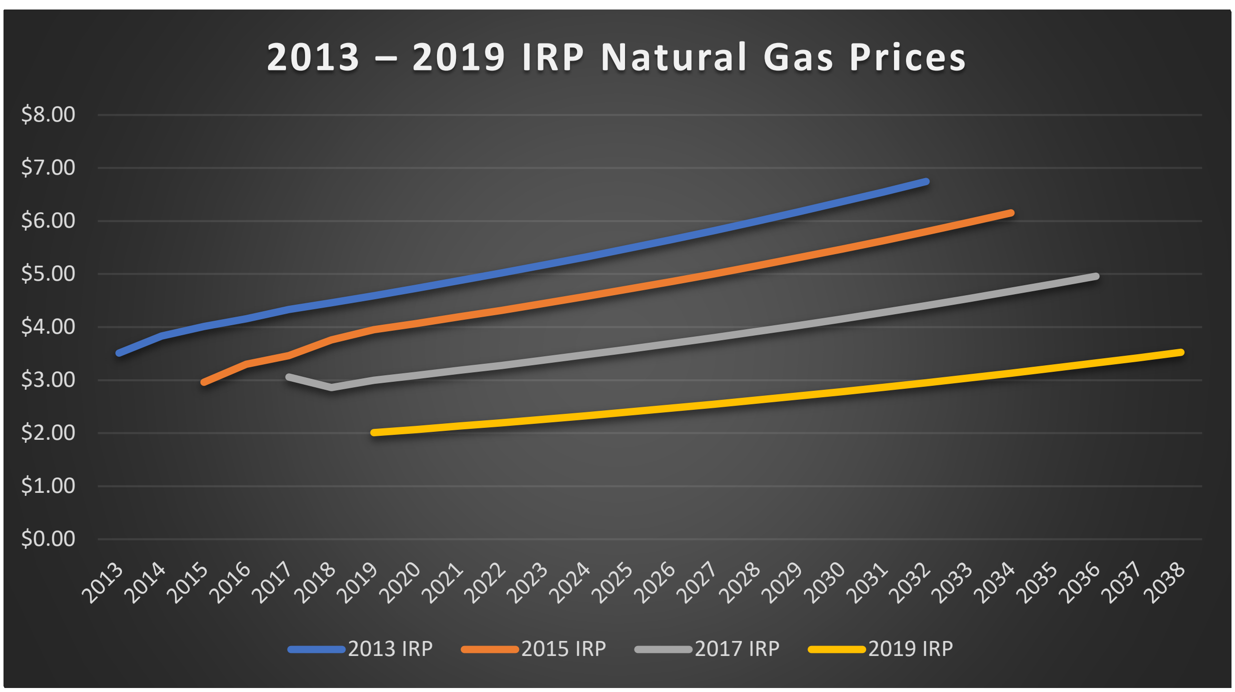


Figure 5 – Natural Gas Commodity Forecast Prices (2013 – 2019 IRPs)

Fuel and Transportation Costs

Lignite coal for the Heskett Station is supplied from Westmoreland Coal Company's Beulah Mine and transported via a rail haul to the power plant. The current coal contract for the Heskett Station runs through December 31, 2021.

Lignite coal for the Lewis & Clark Station is supplied from Westmoreland Coal Company's Savage Mine and transported via truck haul to the power plant. The current coal contract for the Lewis & Clark Station runs through December 31, 2020.

Impacting the competitiveness of the Heskett and Lewis & Clark Stations is rising coal and transportation costs. Figures 6 and 7 show the increase in coal and transportation costs since 2010.

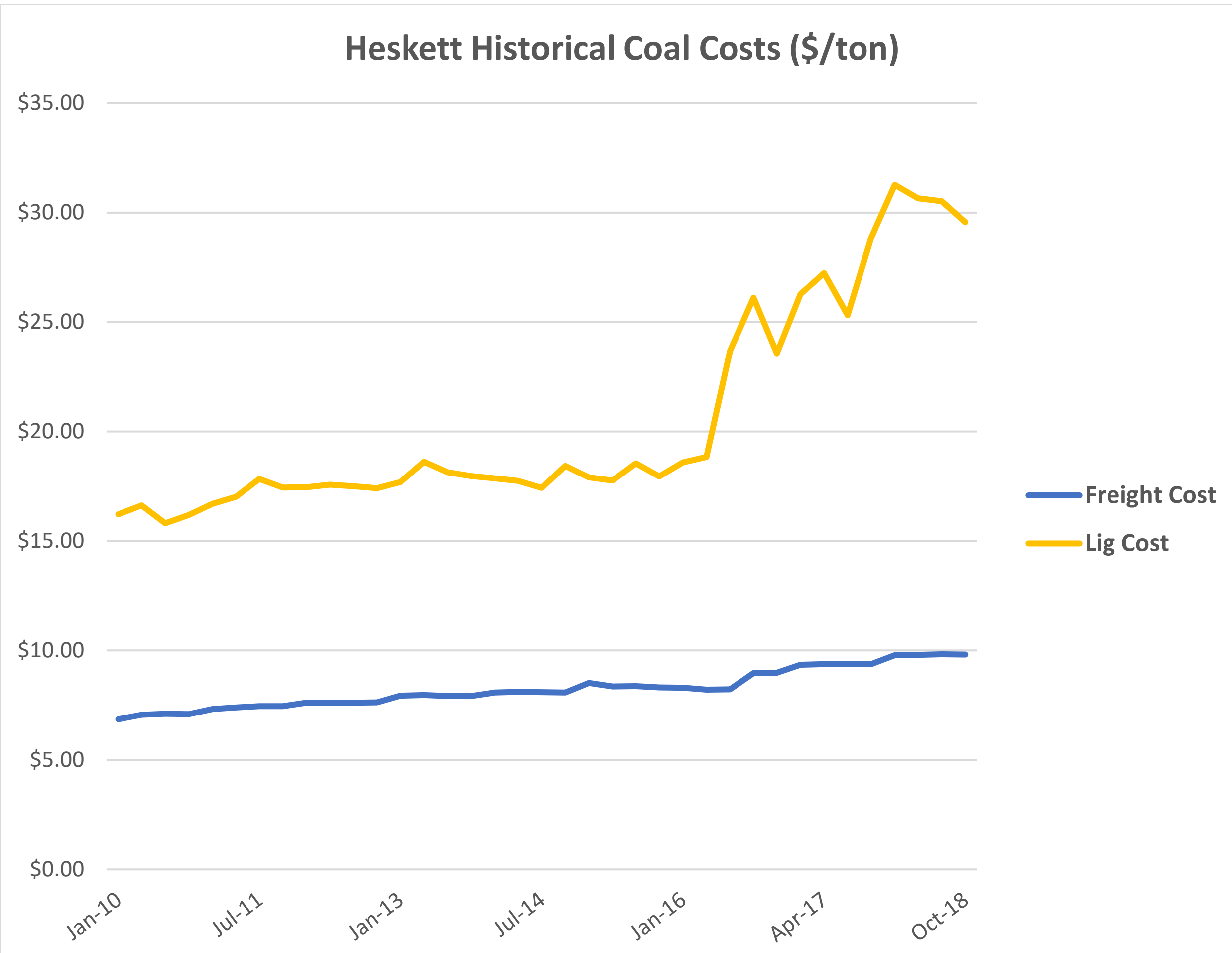


Figure 6 – Heskett Coal and Freight Cost

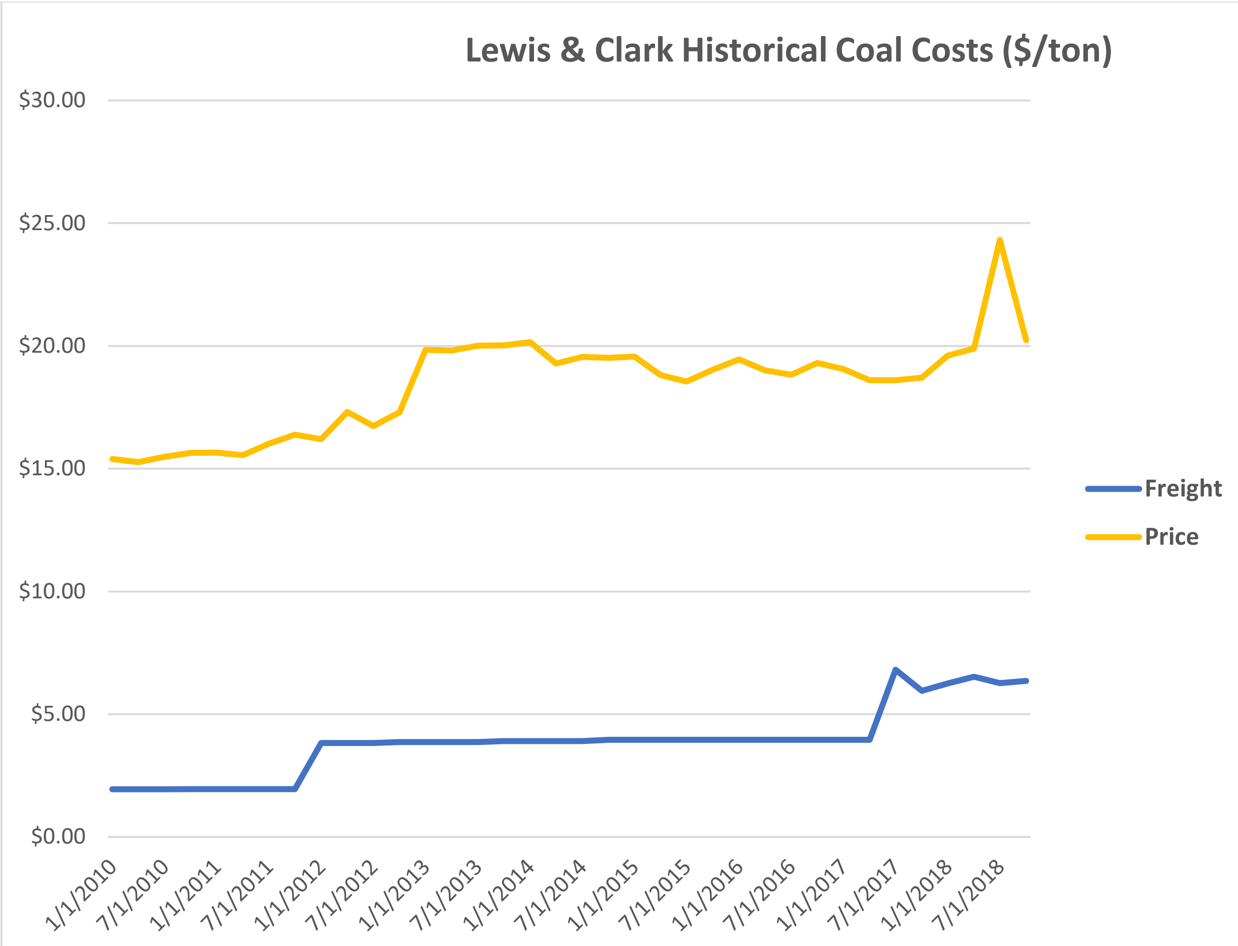


Figure 7 – Lewis & Clark Coal and Freight Cost

These rising coal and freight costs are in contrast with the reduced cost for natural gas and the price of energy available from the MISO energy market which impacts the future economic competitiveness of the units.

Figure 8 is from a MISO presentation on December 7, 2018, to the West Sub-regional planning meeting regarding the MISO Transmission Expansion Plan 2019 (MTEP19) Market Congestion Planning Study (MCPS) Needs Identification. The slide shows MISO's historical coal and natural prices from January 2013 to July 2018. Figure 8 shows coal prices being relatively flat for others in the MISO footprint which is different from Montana-Dakota's experience at the Lewis & Clark and Heskett Stations.

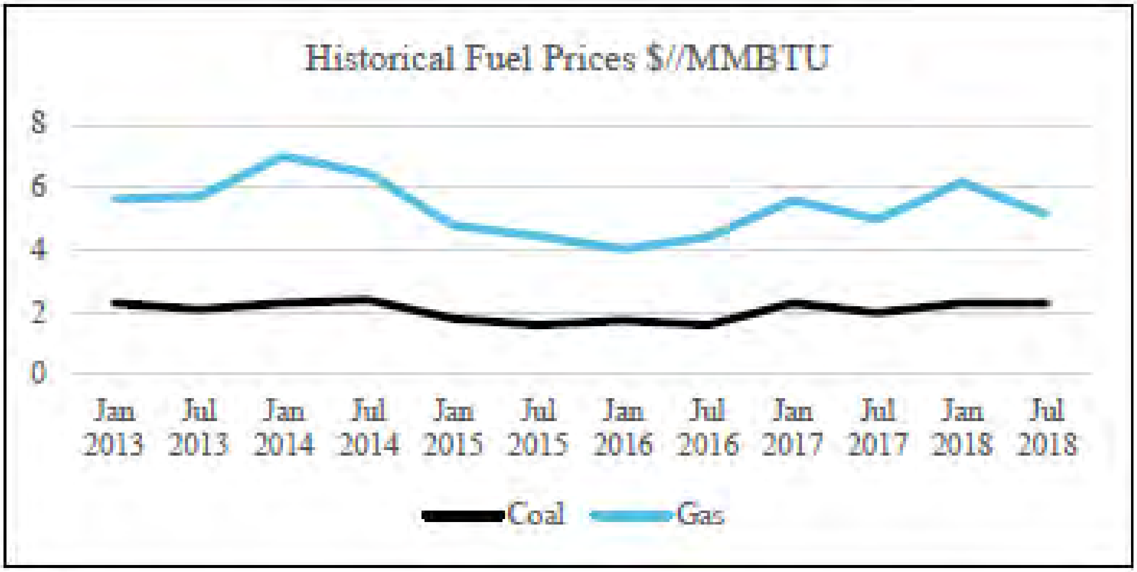


Figure 8 – MISO Historic Coal and Natural Gas Price

An alternate coal supply is not available for the Lewis and Clark Station due to its location and because no rail unloading capability is available on-site.

An alternate coal supply for the Heskett Station is limited, as the plants' environmental pollution control equipment is designed specifically to work with Beulah Mine area lignite coal to ensure environmental permit compliance.

To remain economically viable, fuel and transportation costs for Heskett 1, Heskett 2, and Lewis & Clark 1 would need to be reduced by more than 50 percent, which is unattainable.

Operation and Maintenance (O&M) Costs

Fixed and variable O&M costs have also been increasing at the Heskett 1, Heskett 2, and Lewis & Clark 1 generating stations which impacts the economic competitiveness of the units. Fixed O&M costs are those costs which the Company pays whether the plant is running or not such as labor and maintenance expenses. Variable O&M costs are those costs which are directly related to running the plant such as coal, water and chemical reagents. Figures 9 and 10 show the recent annual operating expenses for the Heskett 1, Heskett 2, and Lewis & Clark 1 generating stations excluding the cost of coal.

To remain economically viable, operations and maintenance costs would need to be reduced for Lewis & Clark 1 to almost zero based upon current fuel prices, which is unattainable. Heskett 1 and Heskett 2 would require a zero-dollar operation and maintenance budget plus a reduction in fuel and transportation costs to remain economically viable, which is unattainable.

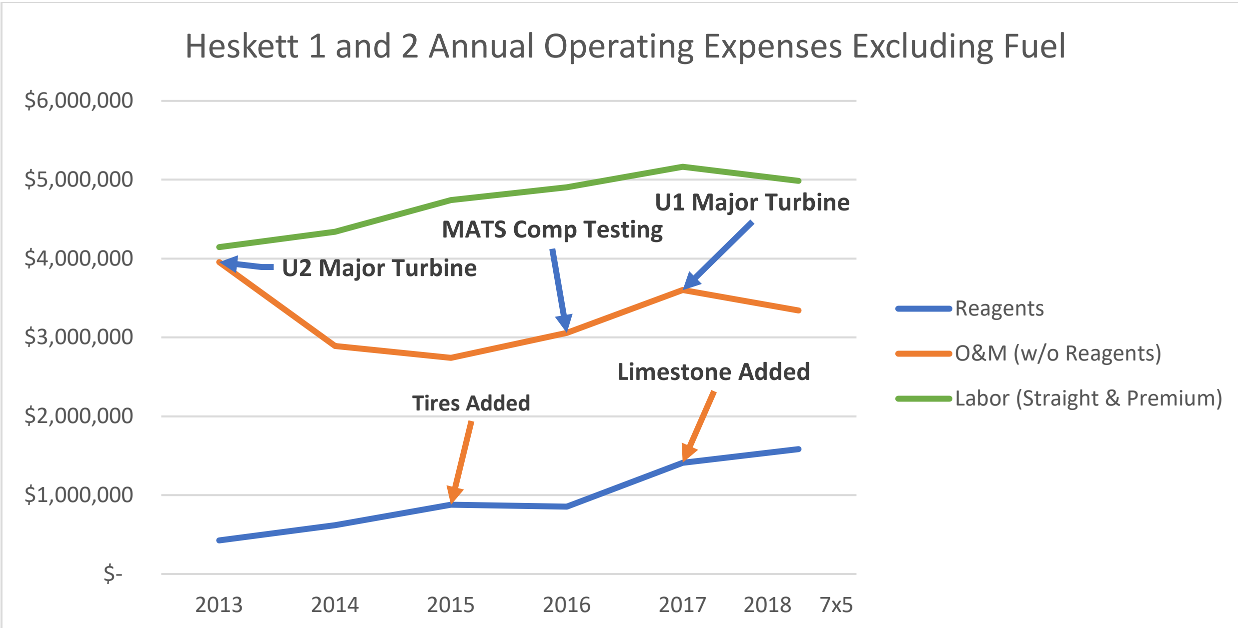


Figure 9 – Heskett 1 and 2 Annual Operating Expenses

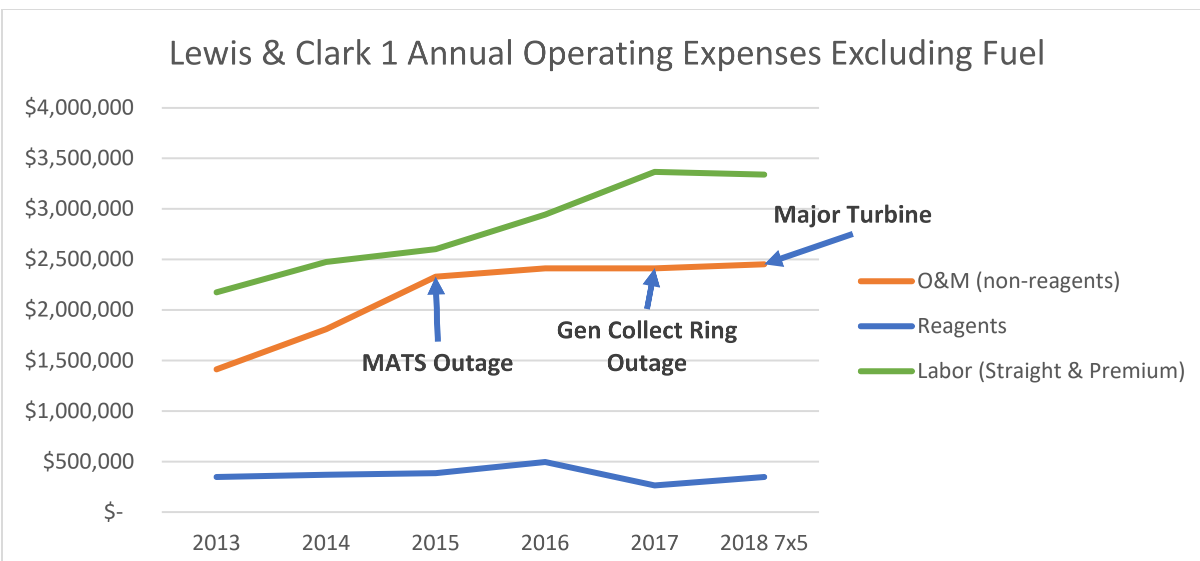


Figure 10 – Lewis & Clark 1 Annual Operating Expenses

Another item to consider related to the future operating expenses for the Heskett 1, Heskett 2, and Lewis & Clark 1 generating units is the next major overhaul dates. Overhauls generally result in significant O&M and capital costs. An average impact on O&M cost for an overhaul based on historical data is $915,000 and capital expenses are specific to the impacted units of property requiring replacing.

Major Unit Outages

	Last	Next
Heskett 1	2017	2023
Heskett 2	2013	2019*
Lewis & Clark 1	2018	2024

* Due to the unit retirement plan, the 2019 overhaul was postponed until 2020 and the scope of the work performed will be limited

Economic Competitiveness Comparison

Montana-Dakota offers its coal-fired generation units into the MISO energy market at the cost of fuel to run the units. This offer price competes against all other generating units within the MISO energy market. A comparison of each unit's fuel cost versus the MISO market price is an indicator of how economically competitive a generation unit is compared to other alternatives.

In 2018, Montana-Dakota's MISO energy market purchase prices averaged $25.85 per MWh. Montana-Dakota's 5-year average MISO energy market purchase price has been $24.44 per MWh.

Figure 11 is a table of fuel, fuel plus variable O&M, and fuel plus all O&M for Montana-Dakota's generating fleet.

	Fuel Cost	Fuel + Variable O&M	Fuel + All O&M	25 Year All-In Cost
	($/MWh)	($/MWh)	($/MWh)	($/MWh)
Heskett 1	48.85	55.47	77.28	
Heskett 2	36.98	43.00	52.92	
Lewis & Clark 1	28.82	35.60	53.76	
Big Stone	20.39	22.47	31.54	
Coyote	20.81	22.92	29.68	
MISO Market Purchases		25.85		
Thunder Spirit Wind 2	0	0	5.52	25.63

Figure 11 – Economic Comparison (2018 FERC Form 1)

The all-in-cost of Thunder Spirit Wind 2 represents the levelized 25-year capital and operating and maintenance costs for the project, less production tax credits that the project receives. Costs for Thunder Spirit Wind 2 are included in Figure 11 to show the relative cost of new wind projects.

The age, size and technology of the Heskett 1, Heskett 2, and Lewis & Clark 1 generating units makes these generation resources less competitive than larger and newer units because the units lack economies of scale and operating efficiencies. In addition, Heskett 1, Heskett 2, and Lewis & Clark 1 are not mine-mouth facilities and rely on rail and truck haul to deliver coal to the facilities further increasing the cost of generation from these units.

Figure 12 is a MISO Generation Supply curve from SNL which provides the fuel and variable O&M cost (dispatch cost) for the MISO generation fleet. Colors and symbols represent different fuel types of generation on an economic stacking order. Montana-Dakota's coal-fired generators are identified on this graph. The three vertical lines represent the MISO footprint minimum, average, and maximum load for 2017.[1]

[1] 2017 was used for this illustration because it is the most recent FERC Form 1 data available at this time.

Figure 12 shows that Heskett 1, and Heskett 2, and Lewis & Clark 1 are currently above the MISO maximum system load point because of their high fuel cost and high variable O&M as compared to other generating units within the MISO footprint. Note, the units will still dispatch above their minimum output level at times because of other generating or transmission outages in the area.

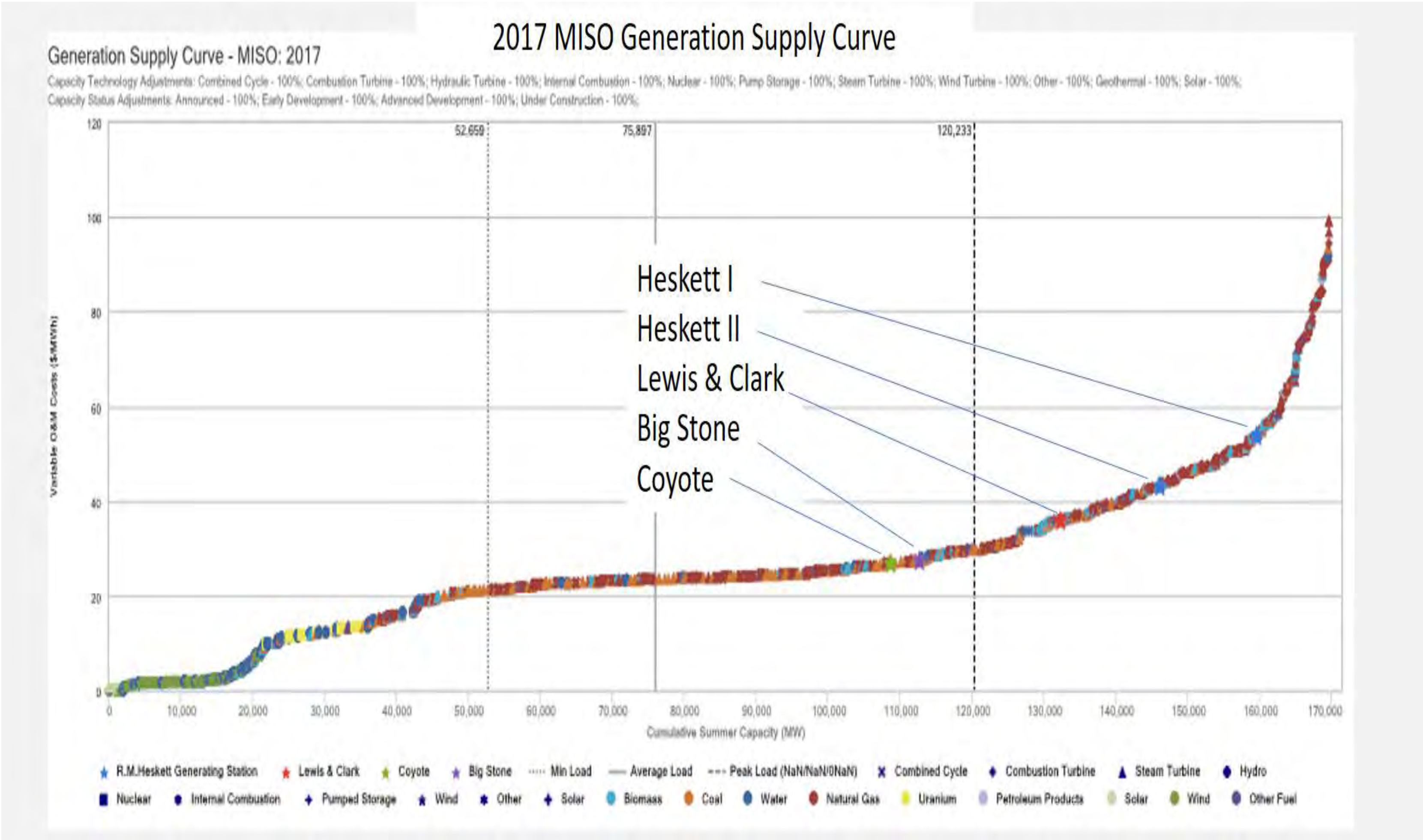


Figure 12 – MISO Generation Supply Curve (SOURCE: S&P Global Market Intelligence)

Retirement Modeling

Specific retirement modeling analysis for Heskett 1, Heskett 2, and Lewis & Clark 1 as part of the 2019 IRP process included: 1) varying the retirement dates for the units in the EGEAS IRP model to compare the total net present value (NPV) of the resource plan over a 50 year period, 2) retiring the units and determining if the EGEAS IRP model selects the units for an additional 5-year period at zero capital costs, and 3) development of a specific revenue requirement model to look at the total net cost impact of retiring the units and replacing that generation with a simple cycle combustion turbine plus market purchases.

Varying retirement dates for Heskett 1, Heskett 2, and Lewis & Clark 1 in the 2019 IRP model from 2029 to 2024 to 2021 show great value in an earlier retire date of 2021 and higher net present value costs to customers if the units continue to run until 2024 or 2029. See Figure 13. The modeled costs to continue to run Heskett 1, Heskett 2, and Lewis & Clark 1 do not include future capital or unit overhaul costs.

Year	**Retire Coal 2021** Plan	**Retire Coal 2024** Plan	**Retire Coal 2029** Plan
2019			
2020			
2021			
2022	Heskett 4, Wind(54 MW), PP(10 MW)	Wind(54 MW), PP(10 MW)	Wind(54 MW), PP(10 MW)
2023	Solar(100 MW)	Solar(100 MW)	Solar(100 MW)
2024			
2025	CC(110 MW)	CC(110 MW)	CC(110 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034		PP(10 MW)	PP(10 MW)
2035		Heskett 4	Heskett 4
2036			
2037			
2038	Solar(5 MW)	Solar(5 MW)	Solar(5 MW)
NPV ($M)	$2,860.37	$2,866.51	$2,942.92
Difference	0.00%	0.21%	2.89%

Figure 13 – Varying Coal Plant Retirement Dates

In another EGEAS model run, the Heskett 1, Heskett 2 and Lewis & Clark 1 units were assumed to be retired at the end of 2021 with the units allowed to be selected by the model as a future resource with a five-year life beginning in 2022 at zero capital cost and at current fuel and O&M costs for the units. The IRP model did not select any of the retired resources for an additional 5-year life.

A separate model comparing the estimated annual revenue requirement assuming Lewis & Clark 1, Heskett 1, and Heskett 2 continue to run to the estimated annual revenue requirement associated with the post-retirement costs for Lewis & Clark 1, Heskett 1, and Heskett 2 plus the cost of replacing their output with market energy purchases, replacement capacity, and a new combustion turbine to be online in 2023. The post retirement costs included the amortization of employee related retention costs necessary to keep the units running through the retirement date, the amortization of the remaining net book values existing at the time of the retirements amortized over a 15-year period and decommissioning costs amortized over 15 years.

The results of this modeling (provided in Figure 14) showed the total cost of the retirement and replacement option was approximately $20 million less on an annual basis in 2023 compared to the total cost to continue to run the units.

Montana-Dakota also considered the impacts of higher MISO energy and natural gas prices which continued to show the retirement and replacement option as the least cost option for customers.

Figure 14 -Estimated Cost to Run Compared to Cost of Retirement and Replacement Power

(000's)

	2023	
Lewis & Clark Non-Fuel Revenue Requirement	$13,959	
Heskett Non-Fuel Revenue Requirement	19,561	
Subtotal Non-Fuel Revenue Requirement Without Retirements	**$33,520**	
Lewis & Clark Retire 12/2020 - Revenue Requirement	0	1/
Heskett Retire 12/2021 - Revenue Requirement	0	2/
Employee Retention Package Amortized over 5 years	1,413	3/
Net Book Value of Assets at Time of Retirement Amortized over 15 Years	8,815	4/
Plant Decommissioning Revenue Requirement	1,416	5/
Heskett IV Non-Fuel Revenue Requirement	10,642	6/
Subtotal Retirement & Heskett IV	**$22,286**	
Change in Non-Fuel Revenue Requirement	**($11,234)**	
Fuel & Purchased Power - Without Retirements	$79,773	
Fuel & Purchased Power Redispatch after Retirements	68,076	
Capacity Replacement - Retirement	2,867	7/
Change in Fuel/Purchased Power	**($8,830)**	
Net Total Change	**($20,064)**	

1/ End of operation 12/31/2020 - End of coal contract 12/31/2020.

2/ End of operation 12/31/2021 - End of coal contract 12/31/2021.

3/ Employee retention package costs assumed to be amortized over 5 years from retirement date of each plant.

4/ Assumes a 15 year Amortization of remaining balance, plus a return of 9.13% on unamortized balance.

5/ Assumes 25% decommissioning completed year 1, 75% year 2 and 100% year 3
at a 15 year amorization and a return of 9.13%.

6/ Assumes plant in service on 1/1/2023 plus incremental Heskett 4 non-fuel O&M costs.

7/ Capacity purchase at $4 per KW month for capacity needs not met by Heskett 4..

Other Considerations

Heskett 1 and Heskett 2 have value for a future resource if the plants continue to run until a replacement unit is built. MISO allows a generator to keep interconnection rights for another unit at the same point-of-interconnection for a period of three years after a unit is retired. This allows Montana-Dakota to avoid unknown network transmission upgrades and associated costs with a new unit. To utilize this generator replacement provision under the MISO tariff, an existing generating unit must continue to run until at least May 16, 2020. A new air permit at Heskett station will be able to utilize some of the existing emissions from Heskett 1 and Heskett 2 to avoid additional studies and additional pollution control equipment, like an SCR, if the units continue to run until a new air permit is issued.

Conclusion

Heskett 1, Heskett 2, and Lewis & Clark 1 should be retired as soon as possible to save customers the most in rates with the logical times for retirement being at the end of 2020 for Lewis & Clark 1 and at the end of 2021 for Heskett 1 and Heskett 2 which are the end dates of their current coal supply agreements.

The age, size and technology of Heskett 1, Heskett 2 and Lewis & Clark 1 makes them less competitive than larger and newer units because they lack economies of scale and operating efficiencies. Heskett 1, Heskett 2 and Lewis & Clark 1 are not mine-mouth facilities and rely on rail and truck haul to deliver coal to the facilities causing additional costs as compared to other coal-fired generating facilities in the area, which leads to the units not being competitive in MISO energy market. Their age, smaller size, and lack of economies of scale also makes their operating cost higher which impacts the economic competitiveness of the units.

Future of Heskett and Lewis and Clark Stations

At the time of the retirement announcement, there were 77 employees between the two coal-plant locations. Once the coal plants are no longer in operation, approximately 10 employees will be required to operate the two-natural gas-fired combustion turbines at Heskett and the two-natural gas-fired combustion engines at Lewis & Clark. A plan is in place intended to maintain staff until the plant retirements and the Company will offer training for employees who wish to fill open positions in other areas of the Company.

Figure 15 shows the Company’s interconnected system generation capacity portfolio before and after retirements based upon nameplate capability:

Fuel Source	2019	2022
Coal	44%	29%
Natural Gas	28%	41%
Renewable	28%	30%

Figure 15 – Montana-Dakota Generation Portfolio Before and After Retirement

MONTANA-DAKOTA UTILITIES CO.

Before the Public Service Commission of Montana

Docket No. 2022.___

Direct Testimony
of
Ronald J. Amen

November 4, 2022

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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 Public Service Commission of Montana ("MPSC" or "Commission")?

A. Yes. I provided expert witness testimony on behalf of Montana-Dakota in Docket No. 2020.06.076.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS"), its Marginal Cost Study (MCS), and discuss their respective 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
- Marginal Cost Study
- 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 L, Statement M, and the following exhibits:

- Exhibit No.____(RJA-1), Marginal Cost Study Summary
- Exhibit No.____(RJA-2), Marginal Energy Costs
- Exhibit No.____(RJA-3), Marginal Capacity Costs
- Exhibit No.____(RJA-4), Marginal Customer Costs
- Exhibit No.____(RJA-5), Marginal Reactive Power Costs
- Exhibit No.____(RJA-6), Revenue at Proposed Rates
- Exhibit No.____(RJA-7), 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:

Table 1

Cost Allocation Methods Summary

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 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):

<u>Test No. 1 – On and Off-Peak Test</u>: 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.

<u>Test No. 2 – Low-to-Annual Peak Test</u>: 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.

[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).

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 Montana load data (2014-2021). Montana-Dakota meets all three FERC tests for using 12 CP for three out of the eight years. For 2016 and 2018 Montana-Dakota meets two of the three tests, and for 2014 and 2021 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	20.3%	65.4%	81.6%
2020	17.8%	68.6%	81.8%
2019	13.2%	72.1%	86.8%
2018	15.9%	65.7%	81.9%
2017	18.9%	66.8%	83.8%
2016	17.6%	67.3%	80.7%
2015	22.1%	62.2%	79.7%
2014	19.3%	61.2%	81.6%

*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 <u>Production</u> 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 <u>Transmission</u> 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..

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 Montana 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.

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	82.8%	17.2%

[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.

364-367	Weighted Average	81.4%	18.6%
368	Line Transformers – Single Phase	74.9%	25.1%
368	Line Transformers – Three Phase	75.4%	24.6%

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 91% of jurisdictional load. The classes making up the remaining 9% 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.

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 actual 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 Rate 10	1.209%	($6,779,215)
Small General Rate 20	2.945%	($2,734,571)
Irrigation Power Rate 25	-0.311%	($326,025)
Large General Primary Rate 30	9.170%	$450,169
Large General Secondary Rate 30	10.984%	$1,993,535
Mandatory TOD Large General Rate 31	10.103%	$114,490
General Space Heat Rate 32	-5.016%	($260,050)
Contract Services Rate 35	3.049%	($2,860,642)
Municipal Pumping Rate 48	4.455%	($90,213)
Outdoor Lighting Rate 52	6.811%	($21,508)
Public Lighting Rate 41	7.896%	$14,356
SYSTEM TOTAL	4.404%	($10,499,674)

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 VIII of this testimony.

Q. Please explain the COSS information contained on Statement L.

A. Statement L, 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 7.525 percent were to be earned for the demand – production and transmission, demand – distribution, energy, and customer cost components of each rate schedule. Statement L also shows the system total rate of return before increase as well as the individual rate schedule rates of return before increase.

Statement L, Schedule L-1, is a summary of the results by the major customer classifications. Statement L, Schedule L-2 is a report of the 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 on Statement L, Schedule L-3.

The COSS is based on a 12 months ended June 30, 2022 test period for Montana electric operations, adjusted for known and measurable changes, as sponsored by Company witness Ms. Vesey.

VI. MARGINAL COST STUDY

Q. Please describe the purpose for the preparation of a marginal cost of service study.

A. Marginal cost studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost studies can inform rate design particularly as it relates to customer and demand related costs for a utility that provides default energy services to retail customers who do not elect an alternate energy supplier. Marginal costs are also important for determining optimal seasons and time-of-use ("TOU") periods when designing TOU rates.

Q. Please describe the Company's Marginal Cost Study ("MCS").

A. Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. As stated earlier, marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs. Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer or load on average. Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration customer density and the expected design loads of those customers. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment is installed, the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

A. Marginal Cost Study Components

Q. Please specify the components of Montana-Dakota's Marginal Cost Study.

A. Montana-Dakota's MCS contains the following components:

- Marginal Generation Capacity Cost;
- Marginal Energy Cost;
- Marginal Transmission Line Capacity Cost;
- Marginal Transmission Substation Capacity Cost;
- Marginal Distribution Capacity Line Cost;
- Marginal Distribution Substation Capacity Cost;
- Marginal Distribution Transformer Capacity Cost;
- Marginal Distribution Customer Cost; and
- Marginal Reactive Power Cost.

Q. What is the test year for the Marginal Cost Study?

A. Consistent with the COSS, the test year for the MCS is the twelve months ending June 30, 2022.

A. Does the MCS comply with the provisions of MPSC Rule Section 38.5.176?

A. Yes. Rule Section 38.5.176 provides guidance for the development of marginal and allocated cost of service analyses filed with the MPSC. Rule Section 38.5.176 specifies the following requirements relevant to electric service:

1) A generic marginal cost model shall also be provided. Marginal cost of service shall be determined for each of the following functions:
    a) Generation, transmission, substation, distribution, and customer for electric filings.
2) Marginal costs shall be determined using the following additional steps:
    a) Classify the functionalized costs as energy (commodity), capacity, reactive power and/or customer related and compute the associated marginal unit costs.
    b) Multiply classified marginal unit costs by allocation factors to compute total marginal cost.

Q. What was the process followed for estimating marginal costs?

A. For capital investment costs, the incremental investment per applicable unit (e.g. kilowatt ("kW"), customer or kilovolt-ampere ("kVA")) the following process was used for the estimate of marginal cost:

- The incremental investment for that component of marginal cost;
- An Economic Carrying Charge Rate ("ECCR") was applied to the incremental investment producing an annualized value for that investment;
- A general plant adder was included representing the annualized cost of the general plant adder;
- Incremental Operations and Maintenance ("O&M") expenses required to support the incremental investment;

- Capacity-related Administrative and General ("A&G") expenses were added representing the overhead functions required to support the incremental investment;
- Estimated property taxes were included in the estimate; and
- Working capital and revenue Taxes were also added.

For marginal cost components composed entirely of expenses (e.g. Marginal Energy Costs) the expenses are the only component. All estimates were escalated to the test year.

Q. Were there changes in the methodologies used in this marginal cost study from those employed the previous MCS?

A. Yes. The ECCR values were calculated on a real basis whereas the previous study calculated the ECCR on a nominal basis. The real ECCR produces an equal value over the life of the respective capital asset, whereas the nominal ECCR increases over time. The nominal rate describes the carrying charge rate without any correction for the effects of inflation, as it refers to the total of the real carrying charge rate plus a projected rate of inflation. While nominal carrying charge rates can indicate current market and economic conditions, real carrying charge rates represent the purchasing power of utilities and investors during periods of volatile inflation. Real ECCR values were used in the Company's marginal cost studies prior to the previous MCS.

B. Marginal Cost Study Results

Q. Please summarize the results of the Marginal Cost Study.

A. The results produced by the MCS are detailed on Exhibit No.____(RJA-2). The information from Exhibit No.____(RJA-2) is summarized in Table 5, below.

Table 5

Marginal Cost Study Results

Rate Class	Energy	Demand	Customer	kVAR	Total
Residential Rate 10	$5,529,678	$7,392,981	$16,747,108	$0	$29,669,767
Small General Primary Rate 20	$16	$7	$707	$0	$730
Small General Secondary Rate 20	$3,267,493	$4,483,283	$6,029,629	$2,251	$13,782,656
Irrigation Power Rate 25	$267,626	$547,866	$327,776	$651	$1,143,919
Large General Primary Rate 30	$2,208,275	$2,701,035	$25,428	$3,988	$4,938,726
Large General Secondary Rate 30	$4,811,905	$4,729,139	$418,337	$6,276	$9,965,657
Optional TOD Large General Primary Rate 31	$360,668	$363,848	$3,326	$574	$728,416
Optional TOD Large General Secondary Rate 31	$6,747	$55,388	$3,278	$284	$65,697
General Space Heat Rate 32	$85,168	$207,095	$14,222	$0	$306,485
Contract Services Rate 35	$5,383,545	$5,134,434	$22,290	$201	$10,540,470
Public Lighting Company Owned Rate 41	$66,818	$84,421	$53,245	$0	$204,484
Public Lighting Municipal Owned Rate 41	$18,321	$23,146	$39,180	$0	$80,647
Municipal Pumping Rate 48	$194,367	$254,888	$152,566	$289	$602,110
Outdoor Lighting Rate 52	$35,978	$78,210	$44,302	$0	$158,490
Total	$22,006,260	$25,722,643	$23,684,526	$14,225	$71,427,654

C. Marginal Generation Capacity Costs

Q. What was the approach used to determine the marginal generation capacity costs?

A. Marginal generation capacity costs are incurred when serving an additional kilowatt of load. In estimating Montana-Dakota's marginal generation capacity costs the incremental cost of the lowest-cost technology to provide capacity was pursued. This approach is consistent with the approach used by Montana-Dakota in previous MCS filings. With the assistance of Montana-Dakota personnel, Atrium determined that the lowest cost resource to provide generation capacity in the Montana-Dakota service territory is one of its commercially available combustion turbines.

Q. Please describe the process for establishing the components of the marginal generation capacity costs.

A. The process for estimating the avoided cost of a combustion turbine is described below. The process followed the following steps:

- Determine the technology choice;
- Calculate the annual cost through the application of an ECCR;
- Identify fixed Operations and Maintenance Expenses ("O&M"); and
- Include adders for Administrative and General Expenses and Cash Working Capital.

The avoided cost of a combustion turbine estimates the marginal generation capital cost as the levelized cost of the least capital intensive generation technology which can serve load regardless of the cost of energy required by that technology. To determine which generation technology is most appropriate, the Company's most recent Integrated Resource Plan was reviewed for information on potential generation technologies available to Montana-Dakota.

Q. What was the result of your review?

A. The technology selected for this MCS was the General Electric 7EA 2x1 ("GE 7EA") Simple Cycle Combustion Turbine ("SCCT"), similar to Montana-Dakota's Heskett 3 and 4, with which the Company has operational experience. The GE 7EA "Heskett Expansion" unit has a lower installed capital cost compared to the other available technologies of $878.00/kW in the Company's 2021 Integrated Resource Plan (IRP),[3] and can be installed within a relatively short lead time

[3] Montana-Dakota 2021 IRP, Volume IV, Attachment C, Table 2-5, Considered Resource Alternatives Available to Montana-Dakota, page 12.

(three years). The capital cost of the marginal generation resource was escalated to the test year 2023.

Q. How was the annual capital cost of the marginal generation resource determined?

A. Once the installed capital costs are calculated for the relevant test year, an ECCR was used to convert one-time capital costs to annualized costs. Consistent with past practice, a levelized ECCR was used to convert the installed cost of the GE 7EA technology to an annual cost.

Q. Please describe the identified fixed O&M expenses associated with the marginal generation capacity resource.

A. Fixed O&M expenses for a simple-cycle combustion turbine are those costs which a generation station operator incurs to maintain the unit for dispatch even if no output is produced. Examples of fixed O&M expenses include labor to staff the station, certain taxes and other similar expenses. The total fixed O&M for the GE 7EA technology was $13.77 in 2021, which was then escalated to 2022 dollars, resulting in the total annual installed cost of the marginal generation capacity resource, as shown in Table 6, below and detailed on Exhibit No.___(RJA-4).

Table 6

Total Annual Cost of the Marginal Generation Capacity Resource

Description	Amount
Installed Cost of a GE 7EA (Heskett Expansion) Combustion Turbine	$918.95
Fixed Charge Rate (%)	8.16%
Annual Capital Cost of Combustion Turbine ($/kW)	$74.98
Annual Capital Cost of Incremental General Plant	$4.64
Fixed Operations and Maintenance Expense	$15.08
General and Administrative Expenses	$5.21
Property Taxes	$0.29
Payroll Taxes	$0.56
Revenue Taxes	$0.35
Working Capital Expenses	$-
Annual Installed Cost of Combustion Turbine – 2022$/KW	$101.11

D. Marginal Generation Energy Costs

Q. Please discuss the marginal generation energy costs.

A. Marginal generation energy costs are the costs incurred by Montana-Dakota when the dispatch of their system is increased. MEC can be supplied either by the dispatch of the Company’s own generating units or wholesale power market transactions. The energy cost estimates were supplied by Montana-Dakota from their PLEXOS market model. A summary of the marginal generation energy costs for 2023 are provided in Table 7, below and detailed on Exhibit No.___(RJA-3).

Table 7

Marginal Energy Costs by Season and Time-of-Use

Time of Day	Non-Summer	Summer	Annual
Off-Peak	$26.01	$28.50	N/A
On-Peak	$26.01	$29.56	N/A
All Hours	N/A	N/A	$26.93

E. Marginal Transmission Capacity Costs

Q. Please discuss Montana-Dakota’s Transmission Capacity Costs.

A. Marginal Transmission Capacity Costs are incurred to serve an additional kW of load on the transmission system. The marginal cost analysis assumes that all transmission costs are functionalized as capacity related, with no energy related costs. With the assistance of Company personnel, Montana-Dakota's transmission system was separated into an analysis of transmission lines and an analysis of transmission substations. Marginal cost analysis is focused upon the change in costs which are incurred when the load of a utility increases. Construction of transmission infrastructure also occurs for reasons unrelated to load growth. Listed below are the criteria for construction of transmission infrastructure.

<u>GENERATION INTERCONNECTION</u>

Transmission investment is normally required when a new utility scale generation unit is interconnected to the network. Montana-Dakota did not identify any transmission issues, including MISO and SPP capabilities, that could be mitigated with local generation resource additions as part of the Company's 2021 IRP Analysis. Transmission limitations associated with SPP's transmission system within the Bakken Region have been mitigated with upgrades and new facilities constructed by Basin Electric in the area.[4]

<u>REPLACEMENT OF WORN OR OBSOLETE INFRASTRUCTURE</u>

Montana-Dakota replaces worn-out or obsolete infrastructure in the normal course of business. In the case of transmission infrastructure which replaces existing investment but does not serve new load or increase the capability of the system, equipment in this category is excluded for the calculation of marginal investment.

[4] Ibid, at 13.

ENHANCE TRANSMISSION RELIABILITY

Many transmission projects enhance the reliability of the system and provide value to customers. However, the capability to service new load is unrelated to this investment. Unless a reliability investment serves new load or provides the capability to serve new load it is excluded from the calculation of marginal investment in the transmission system.

In the last decade several major transmission projects have been constructed which increase the capability of enabling transactions from one region to another. Examples of these projects include significant transmission projects which have enabled the export of renewable energy resources such as wind generation to other regions. Other examples of transmission interconnection projects which enable wholesale market access provide arbitrage opportunities between high and low-cost regions. Transmission projects which interconnect wholesale markets do not service new load growth but are justified based upon energy cost savings which they provide. They are therefore excluded from any estimate of marginal transmission investment.

TRANSMISSION PROJECTS ASSOCIATED WITH LOAD GROWTH

The final category of transmission investments is those associated with load growth. By definition, these investments are included in the category of marginal transmission investments. Montana-Dakota provided the annual expenditures in load related transmission investments for the time period 2005 through 2023. When restated into 2022 dollars, Montana-Dakota has made or is expected to make load related transmission investments of $25,680,941 related to load growth during the time period 2005 through 2023.

Q. How was the level of load growth on the Montana-Dakota system determined?

A. Historical load data was sourced from FERC Form 1 and along with the forecasted load data from Montana-Dakota's 2021 IRP formed the basis for determining the level of load growth on the transmission system.

Q. Please describe the development of the marginal transmission capacity costs.

A. The total transmission investment for the analysis period was divided by aforementioned load growth, which provided the average investment per kW of load growth. Marginal transmission O&M expenses were estimated based upon FERC Form 1 data for 2021, excluding transmission O&M not considered marginal. The excluded expenses are the following:

- Account 561 –associated with dispatch and not related to supporting transmission infrastructure;
- Account 565 – Transmission by others excluded as unrelated to supporting transmission infrastructure; and
- Account 562 and 570 – Station operations and maintenance expense were captured in marginal transmission substations costs.

The development of the marginal transmission capacity costs are shown in Table 8, below and detailed on Exhibit No.___(RJA-4).

Table 8

Development of Marginal Transmission Capacity Cost

Description	Amount
Incremental Investment in Transmission Lines	$179.12
Fixed Charge Rate (%)	8.10%
Annual Capital Cost of Transmission Lines ($/kW)	$14.51
Annual Capital Cost of Incremental General Plant	$0.91
Fixed Operations and Maintenance Expense	$10.20
General and Administrative Expenses	$3.52
Property Taxes	$0.31
Payroll Taxes	$0.38
Revenue Taxes	$0.10
Working Capital Expenses	$0.18
Annual Installed Cost of Transmission Lines – 2022$/KW	$30.11

F. Marginal Transmission Substation Costs

Q. Please describe the development of the marginal transmission substation costs.

A. Marginal transmission substation cost provides estimates of the cost of providing a kW of transmission substation capacity; the approach was similar to past marginal cost studies. Montana-Dakota provided a listing of transmission substations recently constructed and the capacity of those substations. The transmission substations were placed or planned to be placed into service during the time period 2005 through 2024 and the historical data is restated to 2022 dollars using the Handy-Whitman Index. The weighted average investment per kW of substation capacity is $138.06 in 2022 dollars. An ECCR was applied to convert the marginal transmission substation investment into an annual cost.

FERC Accounts 562 and 570 capture transmission substation expenses and were the basis for the calculation of marginal transmission substation O&M expense. Data from Montana-Dakota's FERC Form 1 was used to determine the value for 2021. The resulting O&M cost was divided by the transmission peak demand for 2021. The calculation of the marginal transmission substation cost is shown in Table 9, below and detailed on Exhibit No.___(RJA-4).

Table 9

Marginal Transmission Substation Capacity Cost

Description	Amount
Incremental Investment in Transmission Substations	$138.06
Fixed Charge Rate (%)	8.06%
Annual Capital Cost of Transmission Substations ($/kW)	$11.12
Annual Capital Cost of Incremental General Plant	$0.70
Fixed Operations and Maintenance Expense	$3.50
General and Administrative Expenses	$1.21
Property Taxes	$0.24
Payroll Taxes	$0.13
Revenue Taxes	$0.06
Working Capital Expenses	$0.14
Annual Installed Cost of Transmission Substations – 2022$/KW	$17.10

G. Marginal Distribution Capacity Costs

Q. Please define the distinction between Marginal Distribution Capacity costs and Marginal Distribution Customer costs.

A. Marginal distribution costs are classified as either marginal distribution capacity costs or marginal distribution customer costs. Marginal distribution capacity costs are defined as those costs which are triggered by a change in demand by a customer, the components of which would be a portion of the elements of the distribution system including conductors, poles transformers and other related infrastructure which change as demand on the distribution system increases. Marginal distribution customer costs are defined as the costs triggered when a customer interconnects to the distribution system, the components of which include the meters, service drops and the portion of conductors, poles transformers and other related infrastructure which does not change as demand increases but are related to the number of customers served by the distribution system. Consistent with past Company practice, distribution costs were separated into a capacity and customer components using a Minimum System Analysis, discussed earlier in Section V. B. of my testimony, and summarized in Table 3 in that Section and detailed on Exhibit No.____(RJA-5).

Q. Please describe the development of the marginal distribution line capacity costs.

A. The marginal distribution line investment was calculated as the capacity-related Montana portion of distribution line investment divided by the Montana jurisdiction NCP producing Incremental Investment per kW. Marginal distribution Line Expense was calculated as the capacity-related portion of O&M Expenses. O&M expenses related to substations, meters, transformers, and street lighting were excluded from the calculation. The marginal distribution line costs are summarized in Table 10, below and are shown on Exhibit No.____(RJA-4).

Table 10

Marginal Distribution Line Capacity Cost

Description	Amount
Incremental Investment in Distribution Lines	$192.74
Fixed Charge Rate (%)	8.24%
Annual Capital Cost of Distribution Lines ($/kW)	$15.89
Annual Capital Cost of Incremental General Plant	$0.97
Fixed Operations and Maintenance Expense	$3.48
General and Administrative Expenses	$1.20
Property Taxes	$0.73
Payroll Taxes	$0.13
Revenue Taxes	$0.08
Working Capital Expenses	$0.20
Annual Installed Cost of Distribution Lines – 2022$/KW	$22.68

Q. Please describe the development of the marginal distribution substation costs.

A. The estimation of marginal distribution substation costs was performed in a manner similar to transmission substations. Information on recent distribution substations constructed by Montana-Dakota was provided. Marginal distribution substation expenses were estimated based upon the Montana jurisdictional values for Accounts 582 and 592 divided by the Montana jurisdictional NCP. The calculation of marginal distribution substation cost is summarized in Table 11, below and shown on Exhibit No. ____(RJA-4).

Table 11

Marginal Distribution Substation Capacity Cost

Description	Amount
Distribution Substation Investment per Kilowatt (2022$/kW)	$138.35
Fixed Charge Rate (%)	8.19%
Annual Capital Cost of Distribution Substations ($/kW)	$11.33
Annual Capital Cost of Incremental General Plant	$0.70
Fixed Operations and Maintenance Expense	$0.85
General and Administrative Expenses	$0.29
Property Taxes	$0.52
Payroll Taxes	$0.03
Revenue Taxes	$0.05
Working Capital Expenses	$0.14
Annual Installed Cost of Distribution Substations – 2022$/KW	$13.91

Q. Please describe the development of the marginal distribution transformer costs.

A. Marginal distribution transformer costs were estimated based upon the weighted average number of single-phase and three-phase transformers installed in Montana. The Minimum System analysis previously discussed in Section V. B. was used to identify which portion of the transformers were customer-related versus capacity-related. The calculation of the capacity portion of marginal distribution transformer cost is summarized in Table 12, below and shown on Exhibit No. ____(RJA-4).

Table 12

Marginal Distribution Transformer Capacity Cost

Description	Amount
Capacity Related Transformer Investment per Kilowatt	$30.02
Fixed Charge Rate (%)	8.24%
Annual Capital Cost of Capacity Related Transformer Investment ($/kW)	$2.47
Annual Capital Cost of Incremental General Plant	$0.15
Fixed Operations and Maintenance Expense	$0.10
General and Administrative Expenses	$0.04
Property Taxes	$0.11
Payroll Taxes	$-
Revenue Taxes	$0.01
Working Capital Expenses	$0.03
Marginal Transformer Capacity Cost – 2022$/KW	$2.92

H. Marginal Distribution Customer Costs

Q. Please describe the development of the marginal distribution customer costs.

A. Marginal distribution customer costs are defined as the cost to provide a customer access to service regardless of the level of usage, the components of which are listed below:

- Customer related Transformer costs;
- Customer related Distribution lines costs;
- The cost of Services; and
- The cost of Meters.

The customer-related distribution investment is summarized in Table 13, below and presented on Exhibit No.____(RJA-5).

Table 13

Components of Customer-Related Distribution Investment by Tariff Class

Rate Class	Transformer	Distribution Lines	Services	Meter	Total Incremental Customer Related Investment
Residential Rate 10	$852.53	$5,347.81	$503.04	$111.04	$6,814.42
Small General Primary Rate 20		$5,347.81		$110.00	$5,457.81
Small General Secondary Rate 20	$2,675.65	$5,347.81	$590.20	$247.90	$8,861.56
Irrigation Power Rate 25	$8,264.71	$5,347.81	$934.11	$428.16	$14,974.79
Large General Primary Rate 30		$5,347.81		$8,151.07	$13,498.88
Large General Secondary Rate 30	$6,239.16	$5,347.81	$1,673.73	$1,239.74	$14,500.44
Optional TOD Large General Primary Rate 31		$5,347.81		$7,063.00	$12,410.81
Optional TOD Large General Secondary Rate 31	$7,646.52	$5,347.81	$582.33	$636.83	$14,213.49
General Space Heat Rate 32		$5,347.81		$875.94	$6,223.75
Contract Services Rate 35		$5,347.81		$8,319.54	$13,667.35
Public Lighting Company Owned Rate 41	$2,781.07	$5,347.81	$404.07	$111.03	$8,643.98
Public Lighting Municipal Owned Rate 41	$2,781.07	$5,347.81	$404.07	$111.03	$8,643.98
Municipal Pumping Rate 48	$5,854.27	$5,347.81	$812.81	$493.08	$12,507.97
Outdoor Lighting Rate 52	$2,957.46	$5,347.81		$964.59	$9,269.86

The estimates of customer-related O&M expense are consistent with the capacity-related O&M Expense calculations previously discussed. A summary of marginal distribution customer costs by tariff class are summarized in Table 14, below and presented on Exhibit No.____(RJA-5).

Table 14

Marginal Distribution Customer Costs by Tariff Class

Rate Class	Capital Recovery	O&M Expenses and Adders	Total Customer Related Marginal Cost
Residential Rate 10	$600.44	$233.58	$834.02
Small General Primary Rate 20	$480.91	$226.59	$707.50
Small General Secondary Rate 20	$780.82	$257.34	$1,038.16
Irrigation Power Rate 25	$1,319.48	$319.40	$1,638.88
Large General Primary Rate 30	$1,189.43	$505.80	$1,695.23
Large General Secondary Rate 30	$1,277.68	$356.45	$1,634.13
Optional TOD Large General Primary Rate 31	$1,093.56	$569.65	$1,663.21
Optional TOD Large General Secondary Rate 31	$1,252.39	$386.57	$1,638.96
General Space Heat Rate 32	$548.39	$340.51	$888.90
Contract Services Rate 35	$1,204.27	$510.33	$1,714.60
Public Lighting Company Owned Rate 41	$761.64	$242.98	$1,004.62
Public Lighting Municipal Owned Rate 41	$761.64	$242.98	$1,004.62
Municipal Pumping Rate 48	$1,102.11	$297.58	$1,399.69
Outdoor Lighting Rate 52	$816.80	$263.74	$1,080.54

I. Marginal Reactive Power Costs

Q. Please describe the development of the marginal reactive power costs.

A. The cost to correct for power factor adjustments is consistent with practices adopted in previous marginal cost studies. The approach calculates the avoided cost of capacitor banks recently installed by the company. The calculation of the marginal cost of reactive power is presented in Table 15, below.

Table 15

Marginal Cost of Reactive Power

Description	Amount
Incremental Investment in Recently Installed Capacitor Banks	$58.35
Fixed Charge Rate (%)	6.33%
Annual Capital Cost of Capacitor Banks ($/kVAR)	$3.69
Annual Capital Cost of Incremental General Plant	$0.29
Fixed Operations and Maintenance Expense	$-
General and Administrative Expenses	$-
Property Taxes	$0.17
Payroll Taxes	$-
Revenue Taxes	$0.01
Working Capital Expenses	$0.06
Marginal Reactive Power Cost – 2022$/kVAR	$4.22

VII. 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.[5]

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 gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the electric utility system is designed and constructed to meet the design day 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

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[5] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

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.

VIII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $10,499,674 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 on Statement L, page 12 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*, on Statement L, page 12). 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 first limit the maximum increase to any customer class below a parity ratio of .75 to 150% of the system average increase, or 13.3%. Second, classes with a parity ratio greater than .75 but less than 1.00 at current rates, will receive the system average increase, or 8.9%. Third, the classes above parity will receive a proportional share of the remaining balance of the revenue increase. Under this option, classes receiving an increase between 8.9% and 13.3% would be brought closer to parity. This option does not mitigate the divergence from parity for those classes above parity due to the impact of 1) the proposed recovery of Transmission Expense as a component of Montana-Dakota's Fuel and Purchased Power Tracking Adjustment Rate 58, as discussed by Company witness Ms. Vesey and reflected in the proposed rate design; and 2) the increase in the Base Tax Tracking Adjustment. However, there is moderate movement toward closing the parity gap between those classes above parity and the other classes below parity. (see *Scenario B*, *Minimum Class Increase of 2.4% of System Average, Maximum of 150% Increase, System Average to Others*, on Statement L, page 12).

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), Small General Service (Rate Schedule 20), Irrigation Service (Rate Schedule 25), Large General Service (Rate Schedule 30), Optional TOD Large General Service (Rate Schedule 31), Space Heating (Rate Schedule 32), Small Municipal Service (Rate Schedule 40), Public Lighting Service (Rate Schedule 41), Municipal Pumping Service (Rate Schedule

48), Outdoor Lighting Service (Rate Schedule 52), and Contact Service (Rate Schedule 35), as shown on 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 0.71 to 0.88.

The maximum revenue increase of 13.3% is also proposed for the Irrigation Service, Contract Service, and Space Heating Service, resulting in revenue to cost ratio improvements of 0.61 to 0.78 for Irrigation Service, 0.72 to 0.97 for Contract Service, and 0.32 to 0.43 for Space Heating.

The overall revenue increase of 8.9% is proposed for the Small General Service, Municipal Pumping Service, and Outdoor Lighting Service, resulting in revenue to cost ratio movement of 0.77 to 0.91 for Small General Service, 0.83 to 1.00 for Municipal Pumping Service, and 0.88 to 1.02 for Outdoor Lighting Service.

After these class increases to base rates are made, there remains a balance of $519,487 that was allocated to the remining rate classes that are above parity in proportion to their current revenue.

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 on Statement L, page 12 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 revenue adjustments will mean these classes will continue to be higher than their current parity ratio levels relative to unity.

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 M, pages 1-4, present 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 $10,499,415 to the respective rate schedules is presented on Statement M, page 4. The revenue increases as a percentage of total class revenues range from 19.16% to Residential, 15.09% to Small General, 12.87% to Large General, 8.24% to Public Lighting, 15.40% to Municipal Pumping, and 13.48% to Outdoor Lighting.

Q. Has Montana-Dakota prepared overall revenue impacts by Customer Class?

A. Yes. Total overall customer class revenues at proposed rates and percentage impacts are presented on Exhibit No.____(RJA-6).

IX. 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 M:

- Residential Service (Rate 10 & 16);
- Small General Service (Rates 20 & 26);
- Irrigation Service (Rate 25);
- Large General Service (Rates 30 & 31– Primary);
- Large General Service (Rate 32);
- Contract Service (Rate 35); and
- Municipal Pumping Service (Rate 48).

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement M the Basic Service Charge under Residential Rate 10 is proposed at $0.25 per day, which reflects an average monthly charge of $7.60, an increase of approximately $1.82 per month from the currently effective charge. This proposed charge recognizes the $37.15 customer component identified in the embedded class cost of service as shown on Statement L, 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.

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 6 – 23 of Statement M. A summary of the proposed charges for each rate schedule is provided on Statement M page 5.

Q. Please further discuss your proposal to increase the Basic Service Charge component of the previously identified rate schedules.

A. As shown on Schedule L-2, 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. 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.

X. CUSTOMER BILL IMPACTS

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 792 kWh per year is shown on Exhibit No.___(RJA-7), Rate 10 Residential Bill Comparison for electric service. The average monthly increase for this residential customer under the Company's proposed rate design is $16.96 or 19.1%.

Q. Has Montana-Dakota prepared overall bill impacts by Customer Class?

A. Yes. Total overall bill impact revenues and percentages, and base rate bill impact percentages by Customer Class, are presented on Statement M, pages 24-38.

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

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight on the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)
Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Summit Natural Gas of Maine, Inc. (2022)
Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness support for the utility's gas general rate case before the Maine Public Utilities Commission. The case is currently pending before the Maine PUC.

Black Hills Energy Arkansas (2021-2022)
Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for the utility's gas general rate case before the Arkansas Public Service Commission. The case resulted in a settlement before the Arkansas PSC.

Until Electric System and Northern Utilities, Inc. (2021)
Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)
Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022)
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. Mr. Amen provided electric cost of service, class revenue apportionment, rate design, and expert witness support in Montana-Dakota's 2022 general rate case before the North Dakota PSC. The case is pending.

Chesapeake Utilities Corporation (2020 – 2021)
Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018, 2022)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Future project work involves innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:

    - Application Fees
    - Non-Compliance Fees

- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)
Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)
For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)
Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007,

2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)
Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)
Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)
Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)
Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending

mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond

Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)
Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)
Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)
Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- 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 - MONTANA
MARGINAL COST STUDY SUMMARY

Summary Of Marginal Costs By Customer Class and Cost Classification
2022$

Line	Description	Total Energy	Total Demand	Customer	KVAR	Total	Total without KVAR Costs
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e	(g) = b+c+d
1	**Rate / Summary Customer Class**						
2	Residential Rate 10	$ 5,529,678	$ 7,392,981	$ 16,747,108	$ -	$ 29,669,767	$ 29,669,767
3	Small General Primary Rate 20	16	7	707	-	730	730
4	Small General Secondary Rate 20	3,267,493	4,483,283	6,029,629	2,251	13,782,656	13,780,405
6	General Space Heat Rate 32	85,168	207,095	14,222	-	306,485	306,485
5	Irrigation Power Rate 25	267,626	547,866	327,776	651	1,143,919	1,143,268
6	Large General Primary Rate 30	2,208,275	2,701,035	25,428	3,988	4,938,726	4,934,738
7	Large General Secondary Rate 30	4,811,905	4,729,139	418,337	6,276	9,965,657	9,959,381
8	Optional TOD Industrial Primary Rate 31	360,668	363,848	3,326	574	728,416	727,842
9	Optional TOD Industrial Secondary Rate 31	6,747	55,388	3,278	284	65,697	65,413
10	Contract Services Rate 35	5,383,545	5,134,434	22,290	201	10,540,470	10,540,269
11	Municipal Pumping Secondary Rate 48	194,367	254,888	152,566	289	602,110	601,821
12	Outdoor Lighting Rate 52	35,978	78,210	44,302	-	158,490	158,490
13	Public Lighting Company Owned Rate 41	66,818	84,421	53,245	-	204,484	204,484
14	Public Lighting Municipal Owned Rate 41	18,321	23,146	39,180	-	80,647	80,647
15	Total	$ 22,236,605	$ 26,055,741	$ 23,881,394	$ 14,514	$ 72,188,254	$ 72,173,740

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY SUMMARY

Summary Of Marginal Costs By Customer Class, Season, And Time Of Day
2022$

Line	Description	Summer On Peak	Summer Off Peak	Winter On Peak	Winter Off Peak	Total
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e
1	**Rate / Summary Customer Class**					
2	Residential Rate 10	$ 4,608,902	$ 5,303,968	$ 8,895,921	$ 10,860,996	$ 29,669,787
3	Small General Primary Rate 20	82	162	162	324	730
4	Small General Secondary Rate 20	2,343,598	2,301,908	4,509,413	4,627,745	13,782,664
6	General Space Heat Rate 32	68,802	34,648	132,907	70,127	306,485
5	Irrigation Power Rate 25	198,799	336,888	254,063	354,169	1,143,919
6	Large General Primary Rate 30	756,040	493,703	1,881,606	1,807,378	4,938,727
7	Large General Secondary Rate 30	1,991,463	1,423,428	3,765,992	2,784,777	9,965,660
8	Optional TOD Industrial Primary Rate 31	116,104	132,926	225,185	254,202	728,417
9	Optional TOD Industrial Secondary Rate 31	16,603	4,252	34,400	10,443	65,698
10	Contract Services Rate 35	2,121,097	1,396,320	4,195,944	2,827,110	10,540,471
11	Municipal Pumping Secondary Rate 48	116,468	103,343	205,079	177,220	602,110
12	Outdoor Lighting Rate 52	29,717	22,380	59,937	46,456	158,490
13	Public Lighting Company Owned Rate 41	28,743	36,327	59,482	79,932	204,484
14	Public Lighting Municipal Owned Rate 41	10,620	15,438	21,764	32,826	80,648
15	Total	$ 12,407,038	$ 11,605,691	$ 24,241,855	$ 23,933,705	$ 72,188,290

17 **Notes**
18 (1) Generation Energy Costs spread to period based on Plexos results, Generation Demand allocated to Summer and Winter Peak
19 (2) Non-Generation costs spread to period based on number of hours in period.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY SUMMARY

Summary of Marginal Unit Costs
2022$

Line	Description	$ per KWH	$ per kW per Year	$ per Customer per Year	$ per KVAR per Month	
	(a)	(b)	(c)	(d)	(e)	
1	**Total Energy Related Marginal Cost**					
2	Generation - Average	$ 0.0274				
3	Winter Off-Peak	$ 0.0265				
4	Winter On-Peak	$ 0.0265				
5	Summer Off-Peak	$ 0.0290				
6	Summer On-Peak	$ 0.0301				
7	**Total Capacity Related Marginal Cost**					
8	Generation - Average		$ 101.11			
9	Transmission - Average		$ 30.11			
10	Substation (Transmission) - Average		$ 17.10			
11	Substation (Distribution) - Average		$ 13.91			
12	Distribution (Lines) - Average		$ 22.68			
13	Distribution (Transformers) - Average		$ 2.92			
14	**Reactive Power - Average**				$ 0.35	
15	**Total Customer Related Marginal Cost** (Distribution Lines and Transformer, Service Lines, Metering, Meter Reading / Billing - Average)					
16	Residential Rate 10			$ 834.02		$ 69.50
17	Small General Primary Rate 20			$ 707.50		$ 58.96
18	Small General Secondary Rate 20			$ 1,038.16		$ 86.51
19	General Space Heat Rate 32			$ 888.90		$ 74.07
20	Irrigation Power Rate 25			$ 1,638.88		$ 136.57
21	Large General Primary Rate 30			$ 1,695.23		$ 141.27
22	Large General Secondary Rate 30			$ 1,634.13		$ 136.18
23	Large General TOD Rate 31 -Secondary			$ 1,663.21		$ 138.60
24	Large General TOD Rate 31 -Primary			$ 1,638.96		$ 136.58
25	Contract Services Rate 35			$ 1,714.60		$ 142.88
26	Municipal Pumping Rate 48			$ 1,399.69		$ 116.64
27	Outdoor Lighting Rate 52			$ 1,080.54		$ 90.04
28	Street Lighting Company Owned Rate 41			$ 1,004.62		$ 83.72
29	Street Lighting Municipal Owned Rate 41			$ 1,004.62		$ 83.72
30	**Notes:**					
31	Unit Costs exclude loss adjustments. These unit costs are applied to loss adjusted commodity and demand estimates in order to determine total marginal cost.					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

Energy Related Marginal Costs

Line	Description	Unit	Calculations	Generation Average Annual	Generation Winter Off-Peak	Generation Winter On-Peak	Generation Summer Off-Peak	Generation Summer On-Peak
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
1	Energy Related Direct Plant	$/KWH	= 2 x 3	$ -	$ -	$ -	$ -	$ -
2	Energy Related Plant (2017 $)	$/KWH	= input	$ -	$ -	$ -	$ -	$ -
3	LFCR	%	= input	6.20%	6.20%	6.20%	6.20%	6.20%
4	Energy Related General Plant	$/KWH - Yr	= 6 x 7	$ -	$ -	$ -	$ -	$ -
5	Energy Related General Plant % Loading Factor	%	= input	0.00%	0.00%	0.00%	0.00%	0.00%
6	Energy Related General Plant Cost (2019 $)	$/KWH	= 2 x 5	$ -	$ -	$ -	$ -	$ -
7	LFCR	%	= input	10.99%	10.99%	10.99%	10.99%	10.99%
8	Energy Related O&M Expense	$/KWH	= input	$ 0.0269	$ 0.0260	$ 0.0260	$ 0.0285	$ 0.0296
9	Energy Related G&A Expense	$/KWH	= 10 x 8	$ -	$ -	$ -	$ -	$ -
10	G&A Loading Factor	%	= input	0.00%	0.00%	0.00%	0.00%	0.00%
11	Energy Related Property Taxes	$/KWH	= 12 x 1	$ -	$ -	$ -	$ -	$ -
12	Effective Property Tax as % of Direct Plant	%	= input	0.38950%	10.99011%	10.99011%	10.99011%	10.99011%
13	Energy Related Generation Taxes	$/KWH	= 14	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003
14	Generation Tax (Total Effective Rate)	$/KWH	= input	$ 0.000329	$ 0.000329	$ 0.000329	$ 0.000329	$ 0.000329
15	Energy Related Payroll Taxes	$/KWH	= 16 x (8 + 9)	$ -	$ -	$ -	$ -	$ -
16	Average Payroll Tax As % Of O&M	%	= input	2.77%	2.77%	2.77%	2.77%	2.77%
17	Working Capital Annual Requirement	$/KWH	= 23 x 24	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
18	Materials And Supplies	$/KWH	= 19 x (2 + 6)	$ -	$ -	$ -	$ -	$ -
19	Materials And Supplies Factor	%	= input	1.23%	1.23%	1.23%	1.23%	1.23%
20	Prepayments	$/KWH	= 21 x (2 + 6)	$ -	$ -	$ -	$ -	$ -
21	Prepayments Factor	%	= input	0.08%	0.08%	0.08%	0.08%	0.08%
22	Fuel Stocks Adder	$/KWH	= input	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
23	Total Working Capital	$/KWH	= 18 + 20 + 22	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
24	Required Return On Working Capital	%	= input	7.41%	7.41%	7.41%	7.41%	7.41%
25	Total Revenue Related Taxes Marginal Cost	$/KWH	= 26 x (1+4+8+9+15+17)	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
26	Revenue-Related Tax Rate	%	= input	0.35%	0.35%	0.35%	0.35%	0.35%
27	Total Energy Related Marginal Cost	$/KWH	= 1+4+8+9+15+17+25	$ 0.0274	$ 0.0265	$ 0.0265	$ 0.0290	$ 0.0301

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

Capacity Related Marginal Costs

Line	Description	Unit	Calculations	Generation	Transmission	Substation (Transmission)	Substation (Distribution)	Distribution (Lines)	Distribution (Transformers)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Capacity Related Direct Plant	$/KW - Yr	= 2 x 3	$ 74.98	$ 14.51	$ 11.12	$ 11.33	$ 15.89	$ 2.47
2	Capacity Related Plant (2022 $)	$/KW	= input	$ 918.95	$ 179.12	$ 138.06	$ 138.35	$ 192.74	$ 30.02
3	LFCR	%	= input	8.16%	8.10%	8.06%	8.19%	8.24%	8.24%
4	Capacity Related General Plant	$/KW - Yr	= 6 x 7	$ 4.64	$ 0.91	$ 0.70	$ 0.70	$ 0.97	$ 0.15
5	Capacity Related General Plant % Loading Factor	%	= input	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
6	Capacity Related General Plant Cost (2019$)	$/KW	= 2 x 5	$ 42.26	$ 8.24	$ 6.35	$ 6.36	$ 8.86	$ 1.38
7	LFCR	%	= input	10.99%	10.99%	10.99%	10.99%	10.99%	10.99%
8	Capacity Related O&M Expense	$/KW - Yr	= input	$ 15.08	$ 10.20	$ 3.50	$ 0.85	$ 3.48	$ 0.10
9	Capacity Related G&A Expense	$/KW - Yr	= 10 x 8	$ 5.21	$ 3.52	$ 1.21	$ 0.29	$ 1.20	$ 0.04
10	G&A Loading Factor	%	= input	34.56%	34.56%	34.56%	34.56%	34.56%	34.56%
11	Capacity Related Property Taxes	$/KW - Yr	= 12 x 1	$ 0.29	$ 0.31	$ 0.24	$ 0.52	$ 0.73	$ 0.11
12	Effective Property Tax as % of Direct Plant	%	= input	0.3895%	2.1240%	2.1240%	4.6196%	4.6196%	4.6196%
13	Capacity Related Generation Taxes	$/KW - Yr	= 14	$ -	$ -	$ -	$ -	$ -	$ -
14	Generation Tax (Total Effective Rate)	$/KW	= input	$ -	$ -	$ -	$ -	$ -	$ -
15	Capacity Related Payroll Taxes	$/KW - Yr	= 16 x (8 + 9)	$ 0.56	$ 0.38	$ 0.13	$ 0.03	$ 0.13	$ -
16	Average Payroll Tax As % Of O&M	%	= input	2.77%	2.77%	2.77%	2.77%	2.77%	2.77%
17	Working Capital Annual Requirement	$/KW - Yr	= 23 x 24	$ -	$ 0.18	$ 0.14	$ 0.14	$ 0.20	$ 0.03
18	Materials And Supplies	$/KW	= 19 x (2 + 6)	$ -	$ 2.30	$ 1.78	$ 1.78	$ 2.48	$ 0.39
19	Materials And Supplies Factor	%	= input	0.00%	1.23%	1.23%	1.23%	1.23%	1.23%
20	Prepayments	$/KW	= 21 x (2 + 6)	$ -	$ 0.15	$ 0.12	$ 0.12	$ 0.16	$ 0.03
21	Prepayments Factor	%	= input	0.00%	0.08%	0.08%	0.08%	0.08%	0.08%
22	Fuel Stocks Adder	$/KW	= input						
23	Total Working Capital	$/KW	= 18 + 20 + 22	$ -	$ 2.45	$ 1.90	$ 1.90	$ 2.64	$ 0.42
24	Required Return On Working Capital	%	= input	7.410%	7.41%	7.41%	7.41%	7.41%	7.41%
25	Total Revenue Related Taxes Marginal Cost	$/KW - Yr	= 26 x (1+4+8+9+15+17)	$ 0.35	$ 0.10	$ 0.06	$ 0.05	$ 0.08	$ 0.01
26	Revenue-Related Tax Rate	%	= input	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
27	Total Capacity Related Marginal Cost	$/KW - Yr	= 1+4+8+9+11+13+15+17+2	$ 101.11	$ 30.11	$ 17.10	$ 13.91	$ 22.68	$ 2.92
28	Adjustment for MISO Resource Adequacy Requirements @ 80.4% (Generation Energy Only)	$/KW	= 27 x 80.4%	$ 81.59					

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

CUSTOMER RELATED MARGINAL COSTS
Distribution (Lines and Transformers) and Service Line, Metering, Meter Reading / Billing Functions

Line	Description	Unit	Calculations	Residential Rate 10	Small General Primary Rate 20	Small General Secondary Rate 20	General Space Heat Rate 32	Irrigation Power Rate 25
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Related Direct Plant	$/Cust - Yr	= 2 x 3	$ 561.75	$ 449.92	$ 730.51	$ 513.06	$ 1,234.46
2	Customer Related Plant (2017 $)	$/Cust	= input	$ 6,814.42	$ 5,457.81	$ 8,861.56	$ 6,223.75	$ 14,974.79
3	LFCR	%	= input	8.24%	8.24%	8.24%	8.24%	8.24%
4	Customer Related General Plant	$/Cust - Yr	= 6 x 7	$ 38.69	$ 30.99	$ 50.31	$ 35.33	$ 85.02
5	Customer Related General Plant % Loading Factor	%	= input	4.60%	4.60%	4.60%	4.60%	4.60%
6	Customer Related General Plant Cost (2019 $)	$/Cust	= 2 x 5	$ 313.41	$ 251.02	$ 407.56	$ 286.24	$ 688.72
7	LFCR	%	= input	12.34%	12.34%	12.34%	12.34%	12.34%
8	Customer Related O&M Expense	$/Cust - Yr	= input	$ 118.18	$ 118.18	$ 118.18	$ 118.18	$ 118.18
9	Customer Related Mtr Read, Cust Acct, Svc & Sales O&M Exp	$/Cust - Yr	= input	$ 33.55	$ 33.53	$ 46.39	$ 140.17	$ 76.14
10	Customer Related G&A Expense	$/Cust - Yr	= 11 x 8	$ 40.84	$ 40.84	$ 40.84	$ 40.84	$ 40.84
11	G&A Loading Factor	%	= input	34.56%	34.56%	34.56%	34.56%	34.56%
12	Customer Related Property Taxes	$/Cust - Yr	= 13 x 1	$ 25.95	$ 20.78	$ 33.75	$ 23.70	$ 57.03
13	Effective Property Tax as % of Direct Plant	$/Cust	= input	4.6196%	4.62%	4.62%	4.62%	4.62%
14	Customer Related Generation Taxes	$/Cust - Yr	= 15					
15	Generation Tax (Total Effective Rate)	$/Cust	= input					
16	Customer Related Payroll Taxes	$/Cust - Yr	= 17 x (8 + 10)	$ 5.34	$ 5.34	$ 5.70	$ 8.30	$ 6.52
17	Average Payroll Tax As % Of O&M	%	= input	2.77%	2.77%	2.77%	2.77%	2.77%
18	Working Capital Annual Requirement	$/Cust - Yr	= 24 x 25	$ 6.92	$ 5.54	$ 9.00	$ 6.32	$ 15.20
19	Materials And Supplies	$/Cust	= 20 x (2 + 6)	$ 87.67	$ 70.22	$ 114.01	$ 80.07	$ 192.66
20	Materials And Supplies Factor	%	= input	1.23%	1.23%	1.23%	1.23%	1.23%
21	Prepayments	$/Cust	= 22 x (2 + 6)	$ 5.70	$ 4.57	$ 7.42	$ 5.21	$ 12.53
22	Prepayments Factor	%	= input	0.08%	0.08%	0.08%	0.08%	0.08%
23	Fuel Stocks Adder	$/Cust	= input					
24	Total Working Capital	$/Cust	= 19 + 21 + 23	$ 93.37	$ 74.79	$ 121.43	$ 85.28	$ 205.19
25	Required Return On Working Capital	%	= input	7.41%	7.41%	7.41%	7.41%	7.41%
26	Total Revenue Related Taxes Marginal Cost	$/Cust - Yr	= 27 x (1+4+8+9+10+16+18)	$ 2.80	$ 2.38	$ 3.48	$ 3.00	$ 5.49
27	Revenue-Related Tax Rate	%	= input	0.35%	0.35%	0.35%	0.35%	0.35%
28	Total Customer Related Marginal Cost	$/Cust - Yr	= 1+4+8+9+10+12+16+18+26	$ 834.02	$ 707.50	$ 1,038.16	$ 888.90	$ 1,638.88

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

CUSTOMER RELATED MARGINAL COSTS

Distribution (Lines and Transformers) and Service Line, Metering, Meter Reading / Billing Functions

Line	Description	Unit	Calculations	Large General Primary Rate 30	Large General Secondary Rate 30	Optional TOD Industrial Primary Rate 31	Optional TOD Industrial Secondary Rate 31	Contract Services Rate 35
	(a)		(b)	(h)	(i)	(j)	(k)	(l)
1	Customer Related Direct Plant	$/Cust - Yr	= 2 x 3	$ 1,112.79	$ 1,195.36	$ 1,023.10	$ 1,171.70	$ 1,126.68
2	Customer Related Plant (2017 $)	$/Cust	= input	$ 13,498.88	$ 14,500.44	$ 12,410.81	$ 14,213.49	$ 13,667.35
3	LFCR	%	= input	8.24%	8.24%	8.24%	8.24%	8.24%
4	Customer Related General Plant	$/Cust - Yr	= 6 x 7	$ 76.64	$ 82.32	$ 70.46	$ 80.69	$ 77.59
5	Customer Related General Plant % Loading Factor	%	= input	4.60%	4.60%	4.60%	4.60%	4.60%
6	Customer Related General Plant Cost (2019 $)	$/Cust	= 2 x 5	$ 620.84	$ 666.90	$ 570.80	$ 653.71	$ 628.59
7	LFCR	%	= input	12.34%	12.34%	12.34%	12.34%	12.34%
8	Customer Related O&M Expense	$/Cust - Yr	= input	$ 118.18	$ 118.18	$ 118.18	$ 118.18	$ 118.18
9	Customer Related Mtr Read, Cust Acct, Svc & Sales O&M Exp	$/Cust - Yr	= input	$ 264.22	$ 114.42	$ 331.56	$ 145.05	$ 267.77
10	Customer Related G&A Expense	$/Cust - Yr	= 11 x 8	$ 40.84	$ 40.84	$ 40.84	$ 40.84	$ 40.84
11	G&A Loading Factor	%	= input	34.56%	34.56%	34.56%	34.56%	34.56%
12	Customer Related Property Taxes	$/Cust - Yr	= 13 x 1	$ 51.41	$ 55.22	$ 47.26	$ 54.13	$ 52.05
13	Effective Property Tax as % of Direct Plant	$/Cust	= input	4.62%	4.62%	4.62%	4.62%	4.62%
14	Customer Related Generation Taxes	$/Cust - Yr	= 15					
15	Generation Tax (Total Effective Rate)	$/Cust	= input					
16	Customer Related Payroll Taxes	$/Cust - Yr	= 17 x (8 + 10)	$ 11.74	$ 7.59	$ 13.61	$ 8.44	$ 11.84
17	Average Payroll Tax As % Of O&M	%	= input	2.77%	2.77%	2.77%	2.77%	2.77%
18	Working Capital Annual Requirement	$/Cust - Yr	= 24 x 25	$ 13.71	$ 14.72	$ 12.60	$ 14.43	$ 13.88
19	Materials And Supplies	$/Cust	= 20 x (2 + 6)	$ 173.67	$ 186.56	$ 159.67	$ 182.87	$ 175.84
20	Materials And Supplies Factor	%	= input	1.23%	1.23%	1.23%	1.23%	1.23%
21	Prepayments	$/Cust	= 22 x (2 + 6)	$ 11.30	$ 12.13	$ 10.39	$ 11.89	$ 11.44
22	Prepayments Factor	%	= input	0.08%	0.08%	0.08%	0.08%	0.08%
23	Fuel Stocks Adder	$/Cust	= input					
24	Total Working Capital	$/Cust	= 19 + 21 + 23	$ 184.97	$ 198.69	$ 170.06	$ 194.76	$ 187.28
25	Required Return On Working Capital	%	= input	7.41%	7.41%	7.41%	7.41%	7.41%
26	Total Revenue Related Taxes Marginal Cost	$/Cust - Yr	= 27 x (1+4+8+9+10+16+18)	$ 5.70	$ 5.48	$ 5.60	$ 5.50	$ 5.77
27	Revenue-Related Tax Rate	%	= input	0.35%	0.35%	0.35%	0.35%	0.35%
28	Total Customer Related Marginal Cost	$/Cust - Yr	= 1+4+8+9+10+12+16+18+26	$ 1,695.23	$ 1,634.13	$ 1,663.21	$ 1,638.96	$ 1,714.60

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

CUSTOMER RELATED MARGINAL COSTS

Distribution (Lines and Transformers) and Service Line, Metering, Meter Reading / Billing Functions

Line	Description	Unit	Calculations	Municipal Pumping Secondary Rate 48	Outdoor Lighting Rate 52	Public Lighting Company Owned Rate 41	Public Lighting Municipal Owned Rate 41
	(a)		(b)	(m)	(n)	(o)	(p)
1	Customer Related Direct Plant	$/Cust - Yr	= 2 x 3	$ 1,031.10	$ 764.17	$ 712.57	$ 712.57
2	Customer Related Plant (2017 $)	$/Cust	= input	$ 12,507.97	$ 9,269.86	$ 8,643.98	$ 8,643.98
3	LFCR	%	= input	8.24%	8.24%	8.24%	8.24%
4	Customer Related General Plant	$/Cust - Yr	= 6 x 7	$ 71.01	$ 52.63	$ 49.07	$ 49.07
5	Customer Related General Plant % Loading Factor	%	= input	4.60%	4.60%	4.60%	4.60%
6	Customer Related General Plant Cost (2019 $)	$/Cust	= 2 x 5	$ 575.27	$ 426.34	$ 397.55	$ 397.55
7	LFCR	%	= input	12.34%	12.34%	12.34%	12.34%
8	Customer Related O&M Expense	$/Cust - Yr	= input	$ 118.18	$ 118.18	$ 118.18	$ 118.18
9	Customer Related Mtr Read, Cust Acct, Svc & Sales O&M Exp	$/Cust - Yr	= input	$ 67.26	$ 50.58	$ 33.55	$ 33.55
10	Customer Related G&A Expense	$/Cust - Yr	= 11 x 8	$ 40.84	$ 40.84	$ 40.84	$ 40.84
11	G&A Loading Factor	%	= input	34.56%	34.56%	34.56%	34.56%
12	Customer Related Property Taxes	$/Cust - Yr	= 13 x 1	$ 47.63	$ 35.30	$ 32.92	$ 32.92
13	Effective Property Tax as % of Direct Plant	$/Cust	= input	4.62%	4.62%	4.62%	4.62%
14	Customer Related Generation Taxes	$/Cust - Yr	= 15				
15	Generation Tax (Total Effective Rate)	$/Cust	= input				
16	Customer Related Payroll Taxes	$/Cust - Yr	= 17 x (8 + 10)	$ 6.28	$ 5.81	$ 5.34	$ 5.34
17	Average Payroll Tax As % Of O&M	%	= input	2.77%	2.77%	2.77%	2.77%
18	Working Capital Annual Requirement	$/Cust - Yr	= 24 x 25	$ 12.70	$ 9.41	$ 8.78	$ 8.78
19	Materials And Supplies	$/Cust	= 20 x (2 + 6)	$ 160.92	$ 119.26	$ 111.21	$ 111.21
20	Materials And Supplies Factor	%	= input	1.23%	1.23%	1.23%	1.23%
21	Prepayments	$/Cust	= 22 x (2 + 6)	$ 10.47	$ 7.76	$ 7.23	$ 7.23
22	Prepayments Factor	%	= input	0.08%	0.08%	0.08%	0.08%
23	Fuel Stocks Adder	$/Cust	= input				
24	Total Working Capital	$/Cust	= 19 + 21 + 23	$ 171.39	$ 127.02	$ 118.44	$ 118.44
25	Required Return On Working Capital	%	= input	7.41%	7.41%	7.41%	7.41%
26	Total Revenue Related Taxes Marginal Cost	$/Cust - Yr	= 27 x (1+4+8+9+10+16+18)	$ 4.69	$ 3.62	$ 3.37	$ 3.37
27	Revenue-Related Tax Rate	%	= input	0.35%	0.35%	0.35%	0.35%
28	Total Customer Related Marginal Cost	$/Cust - Yr	= 1+4+8+9+10+12+16+18+26	$ 1,399.69	$ 1,080.54	$ 1,004.62	$ 1,004.62

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
MARGINAL COST STUDY

Reactive Power Related Marginal Costs

Line	Description	Unit	Calculations	Reactive Power
	(a)		(b)	(j)
1	Reactive Power Related Direct Plant	$/KVAR - Yr	= 2 x 3	$ 3.69
2	Reactive Power Related Plant (2017 $)	$/KVAR	= input	$ 58.35
3	LFCR	%	= input	6.33%
4	Reactive Power Related General Plant	$/KVAR - Yr	= 6 x 7	$ 0.29
5	Reactive Power Related General Plant % Loading Factor	= input	= input	4.60%
6	Reactive Power Related General Plant Cost (2019 $)	$/KVAR	= 2 x 5	$ 2.68
7	LFCR	%	= input	10.99%
8	Reactive Power Related O&M Expense	$/KVAR - Yr	= input	$ -
9	Reactive Power Related G&A Expense	$/KVAR - Yr	= 10 x 8	$ -
10	G&A Loading Factor	%	= input	34.56%
11	Reactive Power Related Property Taxes	$/KVAR - Yr	= 12 x 1	$ 0.17
12	Property Tax (Effective Rate)	$/KVAR	= input	4.6196%
13	Reactive Power Related Generation Taxes	$/KVAR - Yr	= 14	
14	Generation Tax (Total Effective Rate)	$/KVAR	= input	
15	Reactive Power Related Payroll Taxes	$/KVAR - Yr	= 16 x (8 + 9)	$ -
16	Average Payroll Tax as % of O&M	%	= input	2.77%
17	Working Capital Annual Requirement	$/KVAR - Yr	= 23 x 24	$ 0.06
18	Materials and Supplies	$/KVAR	= 19 x (2 + 6)	$ 0.72
19	Materials and Supplies Factor	%	= input	1.23%
20	Prepayments	$/KVAR	= 21 x (2 + 6)	$ 0.05
21	Prepayments Factor	%	= input	0.08%
22	Fuel Stocks Adder	$/KVAR	= input	
23	Total Working Capital	$/KVAR	= 18 + 20 + 22	$ 0.77
24	Required Return on Working Capital	%	= input	7.41%
25	Total Revenue Related Taxes Marginal Cost	$/KVAR - Yr	= 26 x (1+4+8+9+15+17)	$ 0.01
26	Revenue-Related Tax Rate	%	= input	0.35%
27	Total Reactive Power Related Marginal Cost	$/KVAR - Yr	= 1+4+8+9+11+13+15+17+25	$ 4.22

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Revenues at Proposed Rates
Pro Forma

	Pro Forma Billing Determinants & Revenues									Rate Design Results		
Customer Class	Customers	Kwh	KW	Basic Service Charge	Energy	Demand	Tax Tracker Revenue	Fuel Rev	Total Revenue Before Increase	Total Proposed Revenue	Revenue Increase	% Incr
Residential Service	20,080	186,438,784		$1,392,548	$13,457,096	$0	$1,509,570	$4,541,649	$20,900,863	24,906,235	$4,005,372	19.2%
Small General Service	6,009	118,522,391	345,013.6	1,432,781	5,148,858	2,093,132	881,851	2,887,204	12,443,826	14,321,661	1,877,835	15.1%
Large General Service	304	439,632,514	941,311.4	401,280	11,506,661	10,103,918	2,237,660	10,526,449	34,775,968	39,250,051	4,474,083	12.9%
Municipal Pumping	109	6,485,116	32,759.4	39,240	208,237	154,693	40,883	157,977	601,030	693,590	92,560	15.4%
Lighting	1,912	4,115,668			347,245		35,300	100,258	482,803	532,368	49,565	10.3%
Total Montana Electric	**28,414**	**755,194,473**	**1,319,084.4**	**$3,265,849**	**$30,668,097**	**$12,351,743**	**$4,705,264**	**$18,213,537**	**$69,204,490**	**$79,703,905**	**$10,499,415**	**15.2%**

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Bill Comparison Worksheet

		Current Rates					Proposed Rates					Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	$ Increase	% Increase
January	1,100	$5.89	$71.72	$26.80	$7.89	$112.30	$7.75	$84.35	$31.90	$10.94	$134.94	$22.64	20.2%
February	900	5.32	58.68	21.92	6.51	92.43	7.00	69.01	26.10	9.03	111.14	18.71	20.2%
March	900	5.89	58.68	21.92	6.56	93.05	7.75	69.01	26.10	9.12	111.98	18.93	20.3%
April	700	5.70	45.64	17.05	5.22	73.61	7.50	53.68	20.30	7.27	88.75	15.14	20.6%
May	600	5.89	39.12	14.62	4.58	64.21	7.75	46.01	17.40	6.38	77.54	13.33	20.8%
June	600	5.70	51.10	14.62	5.77	77.19	7.50	57.99	17.40	7.78	90.67	13.48	17.5%
July	900	5.89	76.65	21.92	8.39	112.85	7.75	86.99	26.10	11.25	132.09	19.24	17.0%
August	1,100	5.89	93.69	26.80	10.12	136.50	7.75	106.32	31.90	13.55	159.52	23.02	16.9%
September	700	5.70	59.62	17.05	6.64	89.01	7.50	67.66	20.30	8.93	104.39	15.38	17.3%
October	600	5.89	39.12	14.62	4.58	64.21	7.75	46.01	17.40	6.38	77.54	13.33	20.8%
November	600	5.70	39.12	14.62	4.56	64.00	7.50	46.01	17.40	6.35	77.26	13.26	20.7%
December	800	5.89	52.16	19.49	5.90	83.44	7.75	61.34	23.20	8.20	100.49	17.05	20.4%
Total	9,500	$69.35	$685.30	$231.43	$76.72	$1,062.80	$91.25	$794.38	$275.50	$105.18	$1,266.31	$203.51	19.1%
Average	792	$5.78	$57.11	$19.29		$88.57	$7.60	$66.20	$22.96		$105.53	$16.96	19.1%

Rate 10 Current		
Basic Service Charge	$0.19	per day
Energy Charge		
Summer Kwh (June-Sept)	$0.08517	per Kwh
Winter Kwh (Oct-May)	$0.06520	per Kwh
F&PP	$0.02436	per Kwh
Tax Tracker Adjustment	10.1657%	

Rate 10 Proposed		
Basic Service Charge	$0.25	per day
Energy Charge		
Summer Kwh (June-Sept)	$0.09665	per Kwh
Winter Kwh (Oct-May)	$0.07668	per Kwh
F&PP & Transmission Expense	$0.02900	per Kwh
Tax Tracker Adjustment	11.8751%	

MONTANA-DAKOTA UTILITIES CO.

Before the Montana Public Service Commission

Docket No. 2022.11.___

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 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 pro forma electric revenues, as included in Statement H, Schedule H-1, of this Application, the proposed rate schedules provided in Appendix B to the Application, and other proposed changes in the Company's Montana electric 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 the 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 North Dakota 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 H, Schedule H-1 and the proposed rate schedules provided in Appendix B to the Application, with the exception of the proposed changes to Fuel and Purchased Power Cost Tracking Adjustment Rate 58, which is sponsored by Ms. Tara Vesey.

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

Pro Forma Revenue Analysis

Q. Please explain the calculation of revenue at current rates included in Statement H, Schedule H-1.

A. The Company applied the Basic Service Charges, Energy Charges, and Demand Charges applicable under each rate schedule, and as authorized in Docket No. D2018.9.60 for Phase II with rates effective September 1, 2020 to the actual June 30, 2022 customers, energy use, and demand to derive the revenues shown on Statement H, Schedule H-1, pages 1 and 2. Incorporated into the pro forma billing determinants was the movement of four Optional Time-of-Day Large General Electric Service Rate 31 customers to the customers' respective rate classifications served under today.

The Fuel and Purchased Power Cost Tracking Adjustments used in revenues reflects the Fuel and Purchased Power Rates developed by Ms. Vesey. The current tax tracking adjustment rate of 10.1657% was then applied to the resulting revenue, excluding Fuel and Purchased Power.

Proposed Tariff Changes

Q. Please briefly describe the changes the Company is proposing to its electric tariff in this rate case.

A. Montana-Dakota is proposing the following changes to the Company's 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 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 proposed rates described by Mr. Ron Amen have been incorporated into the rate schedules.
- Updating the Base Fuel and Purchased Power rates applicable under each rate schedule to reflect the new Base Fuel and Purchased Power rates.
- Proposing a new non-metered service provision applicable under Small General Electric Service Rate 20 whereby the installation of a meter on a customer's service may not be warranted. In the absence of a meter, customers would be billed a predetermined energy use each month based on the operating characteristics of the equipment being served, such as that of Wi-Fi equipment.
- Consistent with the Company's other electric rates schedules, Montana-Dakota 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.

Currently there are no customers served under Rate 38 and therefore no customers are affected by this change.

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.

- Eliminating the reduction to the energy rate charged to municipally owned street lighting systems as currently provided for under Public Lighting Service Rate 41. The Company is proposing the change for the following two reasons: (1) in the Company's 2018 electric rate case, Docket No. D2018.9.60, Montana-Dakota expanded the availability of the tariff to include the lighting of all public streets, alleys and other road right of ways and to no longer limit the availability to only those lighting facilities owned by a municipality, and (2) today, the energy charges billed customers under Rate 41 distinguishes between those facilities owned by a municipal and those owned by the Company. The elimination of this reduced energy charge applicable to municipality-owned systems further recognizes this change in availability and charges the same energy rate regardless of the ownership of the lighting fixtures. Montana is currently the only state the Company bills a discounted energy rate applicable to municipal owned public (or street) lighting systems.

- Proposing changes to Outdoor Lighting Service Rate 52 to reflect current practices.
- 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 3.7 to 1.

The other change the Company is proposing to Rate 112 is to exclude the cost of fuel and purchased power revenue from the revenue used to determine cost participation. As fuel and purchased power is a pass-through cost, the use of revenue, excluding the cost of fuel and purchased power, to determine a customer's cost participation is a better representation of the dollars available to recover the project's investment.

<u>**Load Research Study**</u>

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 Montana electric customers reflecting 2019 data. The study was conducted in response to concerns expressed in the Company's 2018 electric rate case, Docket No. D2018.9.60, regarding Montana-Dakota's use of the customer class's coincident peaks and non-coincident peaks used in that rate case. Montana-Dakota agreed to participate in collaborative meetings in order to improve the process the Company uses to calculate the peaks in its next rate case.

Q. Did Montana-Dakota conduct any meetings regarding its 2020 load research study?

A. Yes. In January 2020, Montana-Dakota presented an introductory meeting where the Company presented the process the Company was going to undertake for its next load research study.

Q. Please briefly describe that load research process here.

A. Montana-Dakota first reviewed its various rate schedules in order to determine which rates would require a random sampling of its customers' energy data 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 Residential Electric Service Rate 10 and Small General Electric Service Rate 20. For all remaining rate schedules, the Company requested that all hourly load data available be provided from the Company's fixed network.

For the 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 consumption levels are equally separated into stratums, of each rate schedule's customers. 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 +/- 5% at a 90% confidence level.

For each 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 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 energy billed for 2019 while maintaining the relationships resulting from the study's data.

Q. Were there any rate schedules the Company did not have hourly load data from the Company's fixed network available to perform a load research study?

A. Yes, hourly load data was not available for Optional Time-of-Day Large General Electric Service Rate 31 (4 customers) and General Electric Space Heating Service Rate 32 (16 customers). As a proxy, the Company used each rate schedule's actual 2019 billing data to determine the rate schedule's load factor for use in the Embedded Class Cost of Service Study. This is the same time period as the Company's 2019 load research study where hourly load data was available.

Hourly load data for Contract Service Rate 35 was also not available through the Company's fixed network. To resolve this gap in data availability, Montana-Dakota used the hourly load data from CPower, for each of the customer's respective substations participating in the Company's commercial demand response program, for use in Montana-Dakota's load research study.

Regarding the Company's two lighting rate schedules, Public Lighting Service Rate 41 and Outdoor Lighting Service Rate 52, Montana-Dakota determined the load factor for each rate schedule based on the estimated number of hours the lights are on each year. The Company felt this an appropriate determination of load factor as the majority of use under these two rate schedules is not metered.

Interim Increase

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue increase of $1,716,219 is proposed to be billed as a separate line item on the bill based on 3.708 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 M attached to the Application for Interim Increase in Electric Rates. The proposed tariff sheets reflect the proposed interim increase of 3.708 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 the Tax Tracking

Adjustment. The interim increase represents an average increase of 2.7 percent over the pro forma revenues. 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 $2.33 from current rates, including Fuel and Purchased Power and Tax Tracking Adjustment.

Q. Does this conclude your testimony?

A. Yes.

Docket No. _________
Exhibit No._____(SB-1)
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Interim Bill Comparison

		Current Rates					Proposed Interim Rates						Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	Basic Service Charge	Energy	F&PP	Tax Tracker	Interim	Total	$ Increase	% Increase
January	1,100	$5.89	$71.72	$26.80	$7.89	$112.30	$5.89	$71.72	$26.80	$7.89	$2.88	$115.18	$2.88	2.6%
February	900	5.32	58.68	21.92	6.51	92.43	5.32	58.68	21.92	6.51	2.37	94.80	2.37	2.6%
March	900	5.89	58.68	21.92	6.56	93.05	5.89	58.68	21.92	6.56	2.39	95.44	2.39	2.6%
April	700	5.70	45.64	17.05	5.22	73.61	5.70	45.64	17.05	5.22	1.90	75.51	1.90	2.6%
May	600	5.89	39.12	14.62	4.58	64.21	5.89	39.12	14.62	4.58	1.67	65.88	1.67	2.6%
June	600	5.70	51.10	14.62	5.77	77.19	5.70	51.10	14.62	5.77	2.11	79.30	2.11	2.7%
July	900	5.89	76.65	21.92	8.39	112.85	5.89	76.65	21.92	8.39	3.06	115.91	3.06	2.7%
August	1,100	5.89	93.69	26.80	10.12	136.50	5.89	93.69	26.80	10.12	3.69	140.19	3.69	2.7%
September	700	5.70	59.62	17.05	6.64	89.01	5.70	59.62	17.05	6.64	2.42	91.43	2.42	2.7%
October	600	5.89	39.12	14.62	4.58	64.21	5.89	39.12	14.62	4.58	1.67	65.88	1.67	2.6%
November	600	5.70	39.12	14.62	4.56	64.00	5.70	39.12	14.62	4.56	1.66	65.66	1.66	2.6%
December	800	5.89	52.16	19.49	5.90	83.44	5.89	52.16	19.49	5.90	2.15	85.59	2.15	2.6%
Total	9,500	$69.35	$685.30	$231.43	$76.72	$1,062.80	$69.35	$685.30	$231.43	$76.72	$27.97	$1,090.77	$27.97	2.6%
Average	792	$5.78	$57.11	$19.29	$6.39	$88.57	$5.78	$57.11	$19.29	$6.39	$2.33	$90.90	$2.33	2.6%

Rate 10 Current		
Basic Service Charge	$0.19	per day
Energy Charge		
Summer Kwh (June-Sept)	$0.08517	per Kwh
Winter Kwh (Oct-May)	$0.06520	per Kwh
Fuel & Purchased Power	$0.02436	per Kwh
Tax Tracking Adjustment	10.1657%	

Rate 10 Proposed Interim		
Basic Service Charge	$0.19	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.08517	per Kwh
Winter Kwh (Oct-May)	$0.06520	per Kwh
Fuel & Purchased Power	$0.02436	per Kwh
Tax Tracking Adjustment	10.1657%	

Interim increase 3.708% of total of bill excluding F&PP and tax tracking adjustment components of bill.