ENGINEERING REPORT

FOR

NORTHERN MUNICIPAL POWER AGENCY, INC.

THIEF RIVER FALLS, MINNESOTA

FOR

2024

WIDSETH

ARCHITECTS ▪ ENGINEERS
SCIENTISTS ▪ SURVEYORS

ENGINEERING REPORT
FOR
NORTHERN MUNICIPAL POWER AGENCY, INC.
THIEF RIVER FALLS, MINNESOTA
FOR
2024

I hereby certify that this report was prepared by me or under my direct supervision and that I am a duly registered Professional Engineer under the laws of the State of Minnesota and the State of North Dakota.

Todd M Forster

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Todd M. Forster

Date: April 25, 2025 MN Reg. No. 45316 ND Reg. No. 5630

Prepared by:

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INTRODUCTION

This report is prepared in compliance with the provisions contained in the Electric System Revenue Bond Prospectus dated October 3, 2017 and November 21, 2023; and Refunding Bond Prospectus dated May 5, 2016, October 3, 2017, and April 3, 2024 which read as follows:

> (2009)
> "*Consulting Engineer*. Northern will retain as Consulting Engineer an independent consulting engineer or engineering firm or corporation having a national and favorable reputation to render continuous engineering counsel. In addition to its other duties, the Consulting Engineer shall prepare, not later than 160 days following the close of each Fiscal Year, an annual engineering report with respect to the Electric System as affected by any applicable agreements for the immediately preceding Fiscal Year, which report shall include a report on the operations of Northern, sufficiency of rates and charges, the conclusions as to changes in operations and the making of repairs and improvements. Copies of such report shall be filed with the Trustee and Northern and sent to Bondholders, at their expense, on written request to Northern."

The above provisions are further reiterated in Bond Resolutions as posted by the Northern Municipal Power Agency Board of Directors.

All bonds issued prior to May 5, 2016 have been paid in full. However, this report contains historical information from previous reports for comparison purposes.

This report is prepared on a calendar year basis to coincide with all other reports prepared by or for Northern Municipal Power Agency and the Coyote Generating Plant.

ENGINEER'S FINDINGS

The 1981, 1985, 1989, 1992, 1997, 1998, 2002, 2007, 2008, 2009, 2010, 2013, 2016, 2017, 2023, and 2024 Bond Prospectus contain projections of the Agency Participants' peak demand, energy requirements and estimated power costs for years ending on April 1st, as well as on a calendar year basis, all as indicated in Exhibit A, attached hereto. Our comparisons herein will be the calendar year actual vs. fiscal year projections.

The 2024 system peak of 88,182 kW as indicated in Exhibit B is 1,030 kW less than that of the 2023 yearly peak of 89,212 kW. The corresponding 2024 kWh energy sales total of 442,363,745 is 10,706,793 lower than the 453,070,538 sold in 2023.

An analysis of the 2024 annual peak demand months of the twelve NMPA participants show a seasonal split between the members with four being winter peakers (Fosston, Halstad, Park River, and Stephen) and eight being summer peakers (Bagley, Baudette, Grafton, Hawley, Roseau, Thief River Falls, Warren, and Warroad). The system saw its highest monthly peak occur during the summer month of June so the system would be considered a summer peaker as well.

2024’s degree days decreased significantly from 2023. This decrease in degree days resulted in a corresponding decrease in energy sales, as 2024’s total sales decreased by 2.36% from 2023 levels. The annual average degree days since the Coyote Station began operations (1982-2024) is 9,472 degree-days with 2024 registering 7,737 degree-days or 18.32% below the 43-year average. 2024’s degree-days is the lowest value recorded in the last 43 years. The second lowest occurred in 2016 at 7,824 annual degree-days. See the tabulation of degree-days in Exhibit M, Page M-1. The heating months of October 2023 through March 2024 saw 20.19% fewer heating degree days than that same period of 2022-23. The cooling months of April 2024 through September 2024 saw 19.23% fewer cooling degree days than that same period of 2023.

The Coyote Station was operated during 2024 by participating owner, Otter Tail Power Company. Monthly reports are issued to all owners on incurred operating costs, inventory activity, and capital expenditures. A sample of a monthly report is provided in Exhibit N. The operating costs for the year ending December 31, 2024, totaled $94,917,195.36 with the Agency share totaling $28,663,987.25 or an average cost of 42.84 mills per kWh (Exhibit H - Page H-1). The average cost of net energy production for the total plant increased to 42.99 mills per kWh, up from 35.74 mills per kWh in 2023. This reflects an increase in average cost of net energy production of 20.28%.

The average power cost per kWh continues to remain stable due to controlling load demand, improving plant efficiency, as well as the effects of refinancing during 1985, 1989, 1992, 1997, 1998, 2002, 2007, 2008, 2009, 2010, 2016, 2017, and 2024 and continued innovative Wholesale Power Pricing policies.

During 2024, the Agency Participant's wholesale cost of power (average cost per kWh) increased 1.426 mills or 1.81% from 78.842 mills in 2023 to 80.268 mills in 2024. Only one of the twelve NMPA participants experienced a decrease in their average wholesale power cost of -0.72 mills/kWh. The remaining eleven participants saw increases of +0.05 to +3.17 mills/kWh. Refer to Exhibit F for details.

Production at the Coyote Station facility decreased in 2024. Facility availability decreased to 87.34% (7,623.52 hours). By comparison, the average yearly availability over the past 35 years was 85.21%. The 2024 availability factor is 2.13% above the 35-year average. Gross generation decreased by 383,265 MWH or 13.93% below that of 2023, resulting in a capacity factor of 58.67% which is 14.85% below the 35-year average capacity factor of 73.52%. (Exhibit G - Page G-1).

The funds advanced by NMPA during 2024 for the operation of the Coyote Station equaled $30,064,001 of the total of $100,100,000 funds advanced by the entire group of Station owners (Exhibit I - Page I-1). NMPA Participants contributed $35,509,475 in revenue of the total of $51,863,573 in revenue derived to offset NMPA's share of the cost of owning and operating the Coyote Station, the cost of the load ratio share of the Minnkota Power Cooperative transmission system, and the cost of internal Agency administrative expense. (Exhibit J - Page J-1).

The Power Supply Coordination Agreement between Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency provides for capital credits to be allocated to the Agency whenever such credits are allocated to other Minnkota Power Cooperative members. For 2024, the total Minnkota Power operating margin was $9,255,066 (after revenue deferral), less the non-operating margins of $7,744,990, leaving a total net operating margin of $1,510,076 to offset prior year losses. Minnkota margin allocation policy is that margins received from operations, provided there are no accumulated prior years' operating losses, are to be allocated back to patrons. In 2023, there was no operating loss, enabling the 2024 net operating margin of $1,510,076 to be allocated. The Agency’s share was $17,559.00. (Exhibit K - Page K-1).

SUMMARY AND CONCLUSIONS

Our investigation and operational review has satisfied us that:

1) The stipulations of the 2016, 2017, 2023, and 2024 Bond Resolutions are being satisfied.

2) All of the Agency's obligations for services to Participating Members and to Minnkota Power Cooperative are fulfilled by the current rate structure.

3) The Coyote Station monthly operating reports indicate that repairs, modifications, and improvements are being completed in a timely fashion. The Coyote Station, under the operation of participating owner Otter Tail Power Company, has made numerous repairs and improvements to the facility since taking over its operation in 1998. Since that time the facility has undergone replacement of and improvements to the LP turbine, feedwater heaters, reheat tubing, scrubbers, boiler combustion optimizer, boiler insulation, secondary air ductwork dampers, air heater seals, boom manlift, stack elevator, conveyor systems, dust collection system, lighting systems, control systems, arc flash compliant switchgear, bottom ash and economizer ash equipment, and IK sootblowers; along with vibration mitigation efforts to the generator; repairs to the boiler feed pump; replacement of fuel oil lines, HP turbine blades, baghouse bag and damper actuator, OPGW microwave system, 10th floor roof, River Station switchgear, Main Station sump pump, mercury system components, Main Station / FGD air compressors, cooling tower, underground air system, nozzles and valves, fire line in boiler building, Water Lab routine analyzer, fire control panels, yard pond pumps, and rotary seal replacements; cleaning of closure ponds; capping of the Blue pit; purchase of a spare exciter; replacement of the plant generator step-up transformer; condensate pumps, glycol heater bundle, bleach tank, pulley, and air heater hot and interm bucket replacements; as well as miscellaneous building repairs and modifications.

4) Coyote Station owners' continual review and development of a 10-year capital plan helps ensure repairs and improvements are budgeted and done in a timely manner.

5) The judicious and economic use of electrical energy continues to be promoted by

Northern Municipal Power Agency, as evidenced by the wholesale-power rate structure. In our opinion, these actions together with the existence of the Power Supply Coordination Agreement between Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency, guaranteeing the sale of the Agency's share of the output of the Coyote Plant, continues to provide the greatest security a Bond Holder could reasonably expect of any Electric System Revenue Bond. We concur with the continuance of the incentives, contained in the rate schedule, that promote off-peak loads. In our opinion, these actions will continue to enhance the competitive position of the Agency Participants.

EXHIBIT A

NORTHERN MUNICIPAL POWER AGENCY

PROJECTED PEAK DEMAND, ENERGY REQUIREMENTS, AND ESTIMATED POWER COSTS

(Per 1981 Bond Prospectus)

Years Ending April 20th	Northern Peak Demand (kW)	Percentage Increase	Energy Requirements (MWh)	Percentage Increase	Annual Load Factor (%)	Northern's Average Annual Cost of Energy-Mills/kWh
1981	55,852 (1)	4.90%	272,370	9.00%	55.67%	15.02
1982	59,110	5.80%	289,460	6.30%	55.90%	16.92
1983	62,410	5.60%	305,420	5.50%	55.86%	18.89
1984	65,420	4.80%	320,420	4.90%	55.91%	22.19
1985	68,420	4.60%	335,490	4.70%	55.97%	23.79
1986	71,430	4.40%	350,660	4.50%	56.04%	27.08
1987	74,430	4.20%	365,890	4.30%	56.12%	30.61
1988	77,460	4.10%	381,210	4.20%	56.18%	34.54
1989	80,490	3.90%	396,620	4.00%	56.25%	38.69
1990	83,540	3.80%	412,090	3.90%	56.31%	38.96
Compound Average Growth Rate		4.60%		4.70%		

Projected Loads (Per 1989 Bond Prospectus)

Year	1991	1992	1993	1994	1995	1996	1997
kW	85,000	88,000	91,000	94,000	97,000	100,000	103,000

(1) Represents actual peak demand through March 20, 1981

EXHIBIT A - Cont.

NORTHERN MUNICIPAL POWER AGENCY

PROJECTED PEAK DEMAND, ENERGY REQUIREMENTS, AND ESTIMATED POWER COSTS

(Per 1992 Bond Prospectus)

Year	Peak Demand (MW)	Controlled Demand (MW)	Energy Requirements (MWh)	Energy Cost-Mills/kWh
1992	90	46	389,500	32.1
1993	92	48	396,655	32
1994	94	50	404,655	31.7
1995	96	52	412,655	31.4
1996	98	54	420,655	31.1
1997	100	56	428,655	34.6
1998	102	58	---	---
1999	104	60	---	---
2000	106	62	---	---
2001	108	64	---	---

EXHIBIT A - Cont.

NORTHERN MUNICIPAL POWER AGENCY

PROJECTED CONTROLLED DEMAND AND ENERGY REQUIREMENTS

Series 1997 Bond Prospectus		
Year	Energy Requirements (MWh)	Controlled Demand (MW)
1997	457	54
1998	468	54
1999	480	54
2000	492	54
2001	504	54
2002	517	54

Refunding Series 1998/1998B Bond Prospectus		
Year	Energy Requirements (MWh)	Controlled Demand (MW)
1998	435	57
1999	446	57
2000	457	57
2001	468	57
2002	480	57

Series 2002 Bond Prospectus		
Year	Energy Requirements (MWh)	Controlled Demand (MW)
2002	474	58
2003	485	59
2004	496	60
2005	507	62
2006	519	63
2007	531	64

EXHIBIT A - Cont.

NORTHERN MUNICIPAL POWER AGENCY

PROJECTED CONTROLLED DEMAND AND ENERGY REQUIREMENTS

Series 2007 Bond Prospectus		
Year	Energy Requirements (MWh)	Controlled Demand (MW)
2007	496	67
2008	504	68
2009	511	69
2010	518	70
2011	525	71
2012	532	72

Series 2008 Bond Prospectus		
Year	Energy Requirements (MWh)	Controlled Demand (MW)
2008	504	66
2009	511	67
2010	518	68
2011	525	69
2012	532	70

EXHIBIT B

NORTHERN MUNICIPAL POWER AGENCY

2024 POWER REQUIREMENTS

MUNICIPAL	PEAK DEMAND kW	BILLING DEMAND kW	METERED kWh
Bagley	4,464	3,049	24,270,066
Baudette	3,490	2,559	20,163,935
Fosston	5,580	4,167	30,722,721
Grafton	9,709	6,958	51,583,394
Halstad	1,980	1,302	7,436,961
Hawley	4,252	2,759	20,591,222
Park River	3,820	3,249	18,888,457
Roseau	7,506	5,221	37,010,252
Stephen	1,891	919	6,967,399
Thief River Falls	29,054	19,229	140,672,520
Warren	3,866	2,512	17,002,173
Warroad	12,570	4,479	67,077,611
System Totals:	88,182	56,403	442,386,711

The NMPA billing demand of 2024 increased 123 kW, or 0.22%, from the previous year. The system peak demand decreased 1,030 kW, or 1.16%, in the past year. A 13.86% decrease in degree days did shrink the rate of energy consumption with kWh usage decreasing 2.36% in 2024 from usage recorded in 2023.

EXHIBIT C
TABLE OF BASE AND WAPA CAPACITY ASSIGNMENTS
TO
PARTICIPANTS OF NORTHERN MUNICIPAL POWER AGENCY
LOAD LEVELS IN KILOWATTS
METERED AT DISTRIBUTION VOLTAGES

Municipal		1985	1986	1987	1988	1989	1990
Bagley:	Base	2,314	2,314	2,314	2,314	2,314	2,314
	WAPA	0	0	0	0	0	0
	Total	2,314	2,314	2,314	2,314	2,314	2,314
Baudette:	Base	1,619	1,619	1,619	1,619	1,619	1,619
	WAPA	0	0	0	0	0	0
	Total	1,619	1,619	1,619	1,619	1,619	1,619
Fosston:	Base	0	582	1,163	1,745	2,326	2,908
	WAPA	2,596	2,077	1,558	1,038	519	0
	Total	2,596	2,659	2,721	2,783	2,845	2,908
Grafton:	Base	0	1,399	2,799	4,198	5,598	6,997
	WAPA	7,199	5,759	4,319	2,880	1,440	0
	Total	7,199	7,158	7,118	7,078	7,038	6,997
Halstad:	Base	0	231	462	693	924	1,155
	WAPA	1,274	1,019	764	510	255	0
	Total	1,274	1,250	1,226	1,203	1,179	1,155
Hawley:	Base	0	315	630	946	1,261	1,576
	WAPA	1,617	1,294	970	647	323	0
	Total	1,617	1,609	1,600	1,593	1,584	1,576
Park River:	Base	0	637	1,273	1,910	2,546	3,183
	WAPA	3,208	2,566	1,925	1,283	642	0
	Total	3,208	3,203	3,198	3,193	3,188	3,183

EXHIBIT C - Cont.

TABLE OF BASE AND WAPA CAPACITY ASSIGNMENTS
TO
PARTICIPANTS OF NORTHERN MUNICIPAL POWER AGENCY
LOAD LEVELS IN KILOWATTS
METERED AT DISTRIBUTION VOLTAGES

Municipal		**1985**	**1986**	**1987**	**1988**	**1989**	**1990**
Roseau:	Base	3,150	3,150	3,150	3,150	3,150	3,150
	WAPA	0	0	0	0	0	0
	Total	3,150	3,150	3,150	3,150	3,150	3,150
Stephen:	Base	0	250	501	751	1,002	1,252
	WAPA	1,285	1,028	771	514	257	0
	Total	1,285	1,278	1,272	1,265	1,259	1,252
Thief River Falls:	Base	0	2,490	4,982	7,472	9,963	12,454
	WAPA	12,488	9,990	7,493	4,995	2,498	0
	Total	12,488	12,480	12,475	12,467	12,461	12,454
Warren:	Base	0	471	943	1,414	1,886	2,357
	WAPA	2,644	2,115	1,586	1,058	529	0
	Total	2,644	2,586	2,529	2,472	2,415	2,357
Warroad:	Base	2,211	2,211	2,211	2,211	2,211	2,211
	WAPA	0	0	0	0	0	0
	Total	2,211	2,211	2,211	2,211	2,211	2,211
Total Base		9,294	15,669	22,047	28,423	34,800	41,176
Total WAPA		32,311	25,848	19,386	12,925	6,463	0
Combined Grand Total		41,605	41,517	41,433	41,348	41,263	41,176

NOTE: The above stated capacity levels will hold for the period May 1 of the listed year to April 30 of the following year.

EXHIBIT D
NORTHERN MUNICIPAL POWER AGENCY
COMPARATIVE MUNICIPAL SALES *
January Thru December, 2022, 2023, & 2024

MUNICIPAL	kWh 2022	kWh 2023	kWh 2024	'23 to '24 % Change
Bagley	25,659,604	25,230,750	24,270,066	-3.8%
Baudette	20,495,187	19,899,073	20,163,935	1.3%
Fosston	31,086,996	30,457,623	30,722,721	0.9%
Grafton	53,411,440	52,673,883	51,575,737	-2.1%
Halstad	8,717,449	8,048,778	7,425,548	-7.7%
Hawley	21,327,751	21,309,659	20,591,222	-3.4%
Park River	19,837,881	19,731,670	18,888,457	-4.3%
Roseau	37,462,476	36,744,877	37,010,252	0.7%
Stephen	7,488,900	7,498,912	6,967,399	-7.1%
Thief River Falls	146,017,450	146,079,133	140,668,624	-3.7%
Warren	17,965,297	17,586,572	17,002,173	-3.3%
Warroad	65,061,778	67,809,608	67,077,611	-1.1%
TOTAL:	454,532,209	453,070,538	442,363,745	-2.36%

* Totals do not include member generation

EXHIBIT E

NORTHERN MUNICIPAL POWER AGENCY

WHOLESALE POWER RATES

Time Period		Rates	
3/20/81 to 3/20/82	Service Charge:	$525.00	per Substation
	Demand Charge:	$3.88	per month per KW Base Demand
		$8.36	per month per KW Excess Demand
	Energy Charge:	8.5	mills per KWH
3/20/82 to 3/20/83	Service Charge:	$575.00	per Substation
	Demand Charge:	$5.50	per month per KW Base Demand
		$11.00	per month per KW Excess Demand
	Energy Charge:	10.8	mills per KWH
3/20/83 to 3/20/84	Service Charge:	$725.00	per Substation
	Demand Charge:	$6.80	per month per KW Base Demand
		$13.60	per month per KW Excess Demand
	Energy Charge:	13.35	mills per KWH
3/20/84 to 3/20/85	Service Charge:	$870.00	per Substation
	Demand Charge:	$7.67	per month per KW Base Demand
		$15.34	per month per KW Excess Demand
	Energy Charge:	13.85	mills per KWH
3/20/85 to 3/20/86	Service Charge:	$913.50	per Substation
	Demand Charge:	$8.05	per month per KW Base Demand
		$16.10	per month per KW Excess Demand
	Energy Charge:	14.55	mills per KWH
3/20/86 to 3/20/87	Service Charge:	$913.50	per Substation
	Demand Charge:	$8.05	per month per KW Base Demand
		$15.30	per month per KW Excess Demand
	Energy Charge:	14.55	mills per KWH
3/20/87 to 3/20/88	Service Charge:	$1,023.00	per Substation
	Demand Charge:	$9.02	per month per KW Base Demand (adj.)
		$16.24	per month per KW Excess Demand
	Energy Charge:	14.55	mills per KWH
3/20/88 to 3/20/89	Service Charge:	$1,293.00	per Substation
	Demand Charge:	$11.40	per month per KW of Billing Demand
	General Energy Charge:	14.55	mills per KWH
	Economic Development Energy Charge:	22.55	mills per KWH

EXHIBIT E - Cont.

3/20/89 to 3/20/90	Service Charge:	$1,000.00	per Substation per month plus $0.09/KW/month of the highest KW demand registered at the substation during 1988
	Demand Charge:	$11.40	per KW per month of demand assigned as billing demand floor, plus $4.00/KW per month of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH
	Economic Development Energy Charge:	$0.02255	(22.55 mills) per KWH
3/20/90 to 3/20/91	Substation Charge:	$1,000.00	per Substation per month plus $0.09/KW/month of the highest KW demand registered at the substation during 1989
	Demand Charge:	$11.40	per KW per month of demand assigned as billing demand floor, plus $4.00/KW per month of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH
	Economic Development Energy Charge:	$0.02255	(22.55 mills) per KWH
3/20/91 to 3/20/92	Substation Charge:	$1,000.00	per Substation per month plus $0.09/KW/month of the highest KW demand registered at the substation during 1990
	Demand Charge:	$11.40	per KW per month of demand assigned as billing demand floor, plus $4.00/KW per month of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH
	Economic Development Energy Charge:	$0.02455	(24.55 mills) per KWH
3/20/92 to 3/20/93	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1991
	Demand Charge:	$133.20	per KW per year ($11.10/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH
	Economic Development Energy Charge:	$0.02455	(24.55 mills) per KWH calculated as $0.01 (10 mills) over the energy charge

EXHIBIT E - Cont.

3/20/93 to 3/20/94	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1992
	Demand Charge:	$133.20	per KW per year ($11.10/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH
	Economic Development Energy Charge:	$0.02455	(24.55 mills) per KWH calculated as $0.01 (10 mills) over the energy charge

3/20/94 to 3/20/95	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1993
	Demand Charge:	$132.00	per KW per year ($11.00/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH

Economic Development
Energy Charge: The energy charge plus the following adder: Mills/KWH

Peak Demand	94/95	95/96	96/97	97/98	98/99	99/00
100-1999 kW	10	10	10	10	10	10
2000 kW plus	4	4	4	4	4	4

3/20/95 to 3/20/96	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1994
	Demand Charge:	$132.00	per KW per year ($11.00/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor
	Energy Charge:	$0.01455	(14.55 mills) per KWH

Economic Development
Energy Charge: The energy charge plus the following adder: Mills/KWH

Peak Demand	95/96	96/97	97/98	98/99	99/00	00/01
100-1999 kW	10	10	10	10	10	10
2000 kW plus	4	5	6	7	8	8

3/20/96 to 3/20/97 Substation Charge: $12,000.00 per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1995

Demand Charge: $132.00 per KW per year ($11.00/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor

Energy Charge: $0.01455 (14.55 mills) per KWH

Economic Development Energy Charge: The energy charge plus the following adder: Mills/KWH

Peak <u>Demand</u>	96/97	97/98	98/99	99/00	00/01	01/02
50 kW Plus	4	5*	6*	7*	8*	8*

*Estimates Only

3/20/97 to 3/20/98 Substation Charge: $12,000.00 per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1996

Demand Charge: $132.00 per KW per year ($11.00/KW/month) of demand assigned as billing demand floor, plus $60.00 per KW per year ($5.00/KW/month) of annual billing demand in excess of the billing demand floor

Energy Charge: $0.01455 (14.55 mills) per KWH

Economic Development Energy Charge: The energy charge plus the following adder: Mills/KWH

Peak <u>Demand</u>	97/98	98/99	99/00	00/01	01/02	02/03
50 kW Plus	4	5*	6*	7*	8*	8*

*Estimates Only

EXHIBIT E - Cont.

3/20/98 to 3/20/99	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub./month)plus $1.08 per KW per year ($0.09/KW/month) of the highest KW demand registered at the substation during 1997
	Demand Charge:	$123.36	per KW per year ($10.28/KW/month) of demand assigned as billing demand floor, plus
			<u>Growth</u>
		$63.00	per KW per year ($5.25/KW/month) of annual winter billing demand in excess of the billing demand floor, plus
			<u>Summer</u>
		$6.00	per kW per year ($0.50/kW/month) of summer billing demand
	Transmission Charge:	$1.00	per kW per year ($0.083/kW/month) of the average of 12 monthly peak loads recorded at the time of the Joint System's monthly peak load during calendar year 1997
	Energy Charge:	$0.01455	(14.55 mills) per KWH

Economic Development
Energy Charge: The energy charge plus the following adder: Mills/KWH

Peak Demand	98/99	99/00	00/01	01/02	02/03
50 kW Plus	5	6*	7*	8*	9*

*Estimates Only

3/20/99 to 3/20/00	Substation Charge:	$12,000.00	per Substation per year ($1,000/sub/month)plus $1.08 per KW per year ($0.09/kW/month) of the highest KW demand registered at the substation during 1998
	Demand Charge:		<u>Base</u>
		$106.00	per KW per year ($8.83/kW/month) of demand assigned as billing demand floor, plus
			<u>Growth</u>
		$66.00	per KW per year ($5.50/kW/month) of annual winter billing demand in excess of the billing demand floor, plus
			<u>Summer</u>
		$12.00	per kW per year ($1.00/kW/month) of summer billing demand
	Transmission Charge:	$6.00	per kW per year ($0.50/kW/month) of the average of 12 monthly peak loads recorded at the time of the Joint System's monthly peak load during calendar year 1998
	Energy Charge:	$0.01455	(14.55 mills) per kWh

Economic Development
Energy Charge: The energy charge plus an energy adder of 5 mills/kWh

3/20/00 to 3/20/01	Substation Charge:		Fixed
		$12,000.00	per Substation per year ($1,000/sub/month)plus
			Variable
		$1.08	$1.08 per KW per year ($0.09/kW/month) of the highest KW demand registered at the substation during 1999
	Demand Charge:		Base
		$87.00	per KW per year ($7.25/kW/month) of demand assigned as billing demand floor, plus
			Growth
		$69.00	per KW per year ($5.75/kW/month) of winter billing demand in excess of the billing demand floor, plus
			Summer
		$18.00	per kW per year ($1.50/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$11.50	per kW per year ($0.96/kW/month) of transmission demand
			Energy
		$0.00050	(0.5 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. The transmission charge represents approximately 40% of the total transmission cost of which the remainder is bundled in the demand charge
	Energy Charge:	$0.01455	(14.55 mills) per kWh
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh
3/20/01 to 3/20/02	Energy Charge:	$0.01460	(14.6 mills) per kWh
	Demand Charge:		Winter
		$71.00	per KW per year ($5.92/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$24.00	per kW per year ($2.00/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$13.90	per kW per year ($1.16/kW/month) of transmission demand
			Energy
		$0.00100	(1.0 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. The transmission charge represents approximately 60% of the total transmission cost of which the remainder is bundled in the demand charge
	Substation Charge:		Fixed
		$12,000.00	per Substation per year ($1,000/sub/month)plus
			Variable
		$1.08	per KW per year ($0.09/kW/month) of the highest KW demand registered at the substation during 2000
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh

3/20/02 to 3/20/03	Energy Charge:	$0.01606	(16.06 mills) per kWh
	Demand Charge:		Winter
		$58.56	per KW per year ($4.88/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$32.52	per kW per year ($2.71/kW/month) of summer billing demand billing demand
	Transmission Charge:		Demand
		$19.08	per kW per year ($1.59/kW/month) of transmission demand
			Energy
		$0.00163	(1.63 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. The transmission charge represents approximately 80% of the total transmission cost of which the remainder is bundled in the demand charge
	Substation Charge:		Fixed
		$13,020.00	per Substation per year ($1,085/sub/month)plus
			Variable
		$1.20	per KW per year ($0.10/kW/month) of the highest KW demand registered at the substation during 2001
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh
3/20/03 to 3/20/04	Energy Charge:	$0.01695	(16.95 mills) per kWh
	Demand Charge:		Winter
		$40.68	per KW per year ($3.39/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$40.68	per kW per year ($3.39/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$22.56	per kW per year ($1.88/kW/month) of transmission demand
			Energy
		$0.00226	(2.26 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$13,560.00	per Substation per year ($1,130/sub/month)plus
			Variable
		$1.20	per KW per year ($0.10/kW/month) of the highest KW demand registered at the substation during 2002
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh

3/20/04 to 3/20/05	Energy Charge:	$0.01837	(18.37 mills) per kWh
	Demand Charge:		Winter
		$44.04	per KW per year ($3.67/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$44.04	per kW per year ($3.67/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$24.48	per kW per year ($2.04/kW/month) of transmission demand
			Energy
		$0.00245	(2.45 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$14,700.00	per Substation per year ($1,225/sub/month)plus
			Variable
		$1.32	per KW per year ($0.11/kW/month) of the highest KW demand registered at the substation during 2003
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh
3/20/05 to 3/20/06	Energy Charge:	$0.01837	(18.37 mills) per kWh
	Demand Charge:		Winter
		$44.04	per KW per year ($3.67/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$44.04	per kW per year ($3.67/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$24.48	per kW per year ($2.04/kW/month) of transmission demand
			Energy
		$0.00245	(2.45 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$14,700.00	per Substation per year ($1,225/sub/month)plus
			Variable
		$1.32	per KW per year ($0.11/kW/month) of the highest KW demand registered at the substation during 2004
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh

3/20/06 to 3/20/07	Energy Charge:	$0.01887	(18.87 mills) per kWh
	Demand Charge:		Winter
		$44.04	per KW per year ($3.67/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$44.04	per kW per year ($3.67/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$24.48	per kW per year ($2.04/kW/month) of transmission demand
			Energy
		$0.00245	(2.45 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$14,700.00	per Substation per year ($1,225/sub/month)plus
			Variable
		$1.32	per KW per year ($0.11/kW/month) of the highest KW demand registered at the substation during 2005
	Economic Development Energy Charge:		The energy charge plus an energy adder of 5 mills/kWh
3/20/07 to 3/20/08	Energy Charge:	$0.02047	(20.47 mills) per kWh
	Demand Charge:		Winter
		$47.76	per KW per year ($3.98/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$47.76	per kW per year ($3.98/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$26.52	per kW per year ($2.21/kW/month) of transmission demand
			Energy
		$0.00266	(2.66 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$15,948.00	per Substation per year ($1,329/sub/month)plus
			Variable
		$1.44	per KW per year ($0.12/kW/month) of the highest KW demand registered at the substation during 2006

EXHIBIT E - Cont.

3/20/08 to 3/20/09	Energy Charge:	$0.02108	(21.08 mills) per kWh
	Demand Charge:		Winter
		$49.20	per KW per year ($4.10/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$49.20	per kW per year ($4.10/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$27.36	per kW per year ($2.28/kW/month) of transmission demand
			Energy
		$0.00274	(2.74 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$16,428.00	per Substation per year ($1,369/sub/month)plus
			Variable
		$1.44	per KW per year ($0.12/kW/month) of the highest KW demand registered at the substation during 2007
3/20/09 to 3/20/10	Energy Charge:	$0.02382	(23.82 mills) per kWh
	Demand Charge:		Winter
		$55.56	per KW per year ($4.63/kW/month) of demand assigned as the billing demand floor, plus
			Summer
		$55.56	per kW per year ($4.63/kW/month) of summer billing demand
	Transmission Charge:		Demand
		$30.96	per kW per year ($2.58/kW/month) of transmission demand
			Energy
		$0.00310	(3.10 mills) per kWh on
		1.)	All energy metered at the substation delivery points
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$18,564.00	per Substation per year ($1,547/sub/month)plus
			Variable
		$1.68	per KW per year ($0.14/kW/month) of the highest KW demand registered at the substation during 2008

EXHIBIT E - Cont.

3/20/10 to 3/20/11	Energy Charge:	$0.02501	(25.01 mills) per kWh
	Energy Surcharge:	$0.00500	(5 mills) per kWh effective through October 20, 2010
	Demand Charge:		Winter
		$58.32	per KW per year ($4.86/kW/month) of winter billing demand, plus
			Summer
		$58.32	per KW per year ($4.86/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$32.52	per kW per year ($2.71/kW/month) of transmission demand
			Energy
		$0.00326	(3.26 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$19,488.00	per Substation per year ($1,624/sub/month), plus
			Variable
		$1.80	per KW per year ($0.15/kW/month) of the highest KW demand registered at the substation during 2009
3/20/11 to 3/20/12	Energy Charge:	$0.03409	(34.09 mills) per kWh
	Energy Surcharge:	$0.00500	(5 mills) per kWh effective through December 20, 2011
	Demand Charge:		Winter
		$79.44	per KW per year ($6.62/kW/month) of winter billing demand, plus
			Summer
		$79.44	per KW per year ($6.62/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$42.84	per kW per year ($3.57/kW/month) of transmission demand
			Energy
		$0.00444	(4.44 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$19,800.00	per Substation per year ($1,650/sub/month), plus
			Variable
		$3.72	per KW per year ($0.31/kW/month) of the highest KW demand registered at the substation during 2010

3/20/12 to 3/20/13	Energy Charge:	$0.03380	(33.80 mills) per kWh
	Energy Surcharge:	$0.00300	(3 mills) per kWh
	Demand Charge:		<u>Winter</u>
		$78.72	per KW per year ($6.56/kW/month) of winter billing demand, plus
			<u>Summer</u>
		$78.72	per KW per year ($6.56/kW/month) of summer billing demand, plus
	Transmission Charge:		<u>Demand</u>
		$42.48	per kW per year ($3.54/kW/month) of transmission demand
			<u>Energy</u>
		$0.00440	(4.40 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		<u>Fixed</u>
		$18,768.00	per Substation per year ($1,564/sub/month), plus
			<u>Variable</u>
		$5.28	per KW per year ($0.44/kW/month) of the highest KW demand registered at the substation during 2011
3/20/13 to 3/20/14	Energy Charge:	$0.03353	(33.53 mills) per kWh
	Energy Surcharge:	$0.00300	(3 mills) per kWh
	Demand Charge:		<u>Winter</u>
		$78.12	per KW per year ($6.51/kW/month) of winter billing demand, plus
			<u>Summer</u>
		$78.12	per KW per year ($6.51/kW/month) of summer billing demand, plus
	Transmission Charge:		<u>Demand</u>
		$42.12	per kW per year ($3.51/kW/month) of transmission demand
			<u>Energy</u>
		$0.00436	(4.36 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		<u>Fixed</u>
		$15,360.00	per Substation per year ($1,280/sub/month), plus
			<u>Variable</u>
		$7.32	per KW per year ($0.61/kW/month) of the highest KW demand registered at the substation during 2012

EXHIBIT E - Cont.

4/1/14 to 4/1/15	Energy Charge:	$0.03353	(33.53 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$78.12	per KW per year ($6.51/kW/month) of winter billing demand, plus
			Summer
		$78.12	per KW per year ($6.51/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$42.12	per kW per year ($3.51/kW/month) of transmission demand
			Energy
		$0.00436	(4.36 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$15,360.00	per Substation per year ($1,280/sub/month), plus
			Variable
		$7.32	per KW per year ($0.61/kW/month) of the highest KW demand registered at the substation during 2013
4/1/15 to 4/1/16	Energy Charge:	$0.03521	(35.21 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$82.08	per KW per year ($6.84/kW/month) of winter billing demand, plus
			Summer
		$82.08	per KW per year ($6.84/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$44.28	per kW per year ($3.69/kW/month) of transmission demand
			Energy
		$0.00458	(4.58 mills) per kWh on
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$16,128.00	per Substation per year ($1,344/sub/month), plus
			Variable
		$7.68	per KW per year ($0.64/kW/month) of the highest KW demand registered at the substation during 2014

EXHIBIT E - Cont.

4/1/16 to 4/1/17	Energy Charge:	$0.03637	(36.37 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$84.84	per kW per year ($7.07/kW/month) of winter billing demand, plus
			Summer
		$84.84	per kW per year ($7.07/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$45.72	per kW per year ($3.81/kW/month) of transmission demand
			Energy
		$0.00473	(4.73 mills) per kWh
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$16,656.00	per Substation per year ($1,388/sub/month), plus
			Variable
		$7.92	per kW per year ($0.66/kW/month) of the highest kW demand registered at the substation during 2015
4/1/17 to 4/1/18	Energy Charge:	$0.03742	(37.42 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$87.36	per kW per year ($7.28/kW/month) of winter billing demand, plus
			Summer
		$87.36	per kW per year ($7.28/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$47.04	per kW per year ($3.92/kW/month) of transmission demand
			Energy
		$0.00487	(4.87 mills) per kWh
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$17,136.00	per Substation per year ($1,428/sub/month), plus
			Variable
		$8.16	per kW per year ($0.68/kW/month) of the highest kW demand registered at the substation during 2016

4/1/18 to 4/1/19	Energy Charge:	$0.03742	(37.42 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$87.36	per kW per year ($7.28/kW/month) of winter billing demand, plus
			Summer
		$87.36	per kW per year ($7.28/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$47.04	per kW per year ($3.92/kW/month) of transmission demand
			Energy
		$0.00487	(4.87 mills) per kWh
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$17,136.00	per Substation per year ($1,428/sub/month), plus
			Variable
		$8.16	per kW per year ($0.68/kW/month) of the highest kW demand registered at the substation during 2017
4/1/19 to 4/1/20	Energy Charge:	$0.03742	(37.42 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$87.36	per kW per year ($7.28/kW/month) of winter billing demand, plus
			Summer
		$87.36	per kW per year ($7.28/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$47.04	per kW per year ($3.92/kW/month) of transmission demand
			Energy
		$0.00487	(4.87 mills) per kWh
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay adequate transmission charge.
	Substation Charge:		Fixed
		$17,136.00	per Substation per year ($1,428/sub/month), plus
			Variable
		$8.16	per kW per year ($0.68/kW/month) of the highest kW demand registered at the substation during 2018

EXHIBIT E - Cont.

4/1/20 to 4/1/21	Energy Charge:	$0.03742	(37.42 mills) per kWh
	Energy Surcharge:	$0.00400	(4 mills) per kWh
	Demand Charge:		Winter
		$87.36	per kW per year ($7.28/kW/month) of winter billing demand, plus
			Summer
		$87.36	per kW per year ($7.28/kW/month) of summer billing demand, plus
	Transmission Charge:		Demand
		$47.04	per kW per year ($3.92/kW/month) of transmission demand
			Energy
		$0.00487	(4.87 mills) per kWh
		1.)	All energy metered at the substation delivery points and
		2.)	All energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Participant or their customers. NMPA reserves the right to require special metering and assess a transmission charge on loads that otherwise would not pay an adequate transmission charge.
	Substation Charge:		Fixed
		$17,136.00	per Substation per year ($1,428/sub/month), plus
			Variable
		$8.16	per kW per year ($0.68/kW/month) of the highest kW demand registered at the substation during 2019

4/1/21 to 4/1/22			
	Production Energy Charge:	$0.03594	(35.94 mills) per kWh
	Production Demand Charge:		
	Winter Demand	$7.28	per kW-month ($87.36 per kW-year)
	Summer Demand	$7.29	per kW-month ($87.48 per kW-year)
	Base Demand	$3.99	per kW-month
	Transmission Charge:		
	Transmission Demand	$3.36	per kW-month ($40.32 per kW-year)
	Transmission Energy	$0.00442	(4.42 mills) per kWh
	Substation Charge:		
	Substation Fixed		
	1) Less than 7,500 kVa	$500	per Substation per month
	2) 7,500 kVa & greater	$1,000	per Substation per month
	Substation Demand	$1.18	per kW-month ($14.16 per kW-year) of the highest one-hour kW peak registered at each substation during 2020

The Production Energy Charge, Production Base Demand, and Transmission Energy Charges are billed monthly based on actual usage. The Production Winter Demand Charge, Production Summer Demand Charge, Transmission Demand Charge, Substation Fixed Charge, and Substation Demand Charge are payable in twelve equal monthly payments.

EXHIBIT E - Cont.

4/1/22 to 4/1/23

Production Energy Charge:	$0.03594	(35.94 mills) per kWh
Production Demand Charge:		
Winter Demand	$7.28	per kW-month ($87.36 per kW-year)
Summer Demand	$7.29	per kW-month ($87.48 per kW-year)
Base Demand	$3.99	per kW-month
Transmission Charge:		
Transmission Demand	$3.36	per kW-month ($40.32 per kW-year)
Transmission Energy	$0.00442	(4.42 mills) per kWh
Substation Charge:		
Substation Fixed		
1) Less than 7,500 kVa	$500	per Substation per month
2) 7,500 kVa & greater	$1,000	per Substation per month
Substation Demand	$1.18	per kW-month ($14.16 per kW-year) of the highest one-hour kW peak registered at each substation during 2021

The Production Energy Charge, Production Base Demand, and Transmission Energy Charges are billed monthly based on actual usage. The Production Winter Demand Charge, Production Summer Demand Charge, Transmission Demand Charge, Substation Fixed Charge, and Substation Demand Charge are payable in twelve equal monthly payments.

4/1/23 to 4/1/24

Production Energy Charge:	$0.03594	(35.94 mills) per kWh
Production Demand Charge:		
Winter Demand	$7.28	per kW-month ($87.36 per kW-year)
Summer Demand	$7.29	per kW-month ($87.48 per kW-year)
Base Demand	$3.99	per kW-month
Transmission Charge:		
Transmission Demand	$3.36	per kW-month ($40.32 per kW-year)
Transmission Energy	$0.00442	(4.42 mills) per kWh
Substation Charge:		
Substation Fixed		
1) Less than 7,500 kVa	$500	per Substation per month
2) 7,500 kVa & greater	$1,000	per Substation per month
Substation Demand	$1.18	per kW-month ($14.16 per kW-year) of the highest one-hour kW peak registered at each substation during 2022

The Production Energy Charge, Production Base Demand, and Transmission Energy Charges are billed monthly based on actual usage. The Production Winter Demand Charge, Production Summer Demand Charge, Transmission Demand Charge, Substation Fixed Charge, and Substation Demand Charge are payable in twelve equal monthly payments.

4/1/24 to 4/1/25

See Pages E-19 through E-39

NOTE: See detailed rate sheets for tables and rules.

April 1, 2024 to April 1, 2025

Northern Wholesale Power Rate Schedule

Northern Municipal Power Agency
Thief River Falls, Minnesota

April 4, 2024

WHOLESALE POWER RATE FOR NORTHERN MUNICIPAL POWER AGENCY FOR THE PERIOD APRIL 1, 2024 TO APRIL 1, 2025

RESOLUTION OF THE BOARD OF DIRECTORS

BE IT RESOLVED that the Board of Directors of Northern Municipal Power Agency (Northern) does hereby authorize and approve the following Wholesale Power Rate for Participants for the period April 1, 2024 to April 1, 2025:

WHOLESALE POWER RATE FOR PARTICIPANTS

Section I – Firm Power and/or Interruptible Energy Services

A. Rate Schedule:

1. Production Energy Charge: $0.03594 (35.94 mills) per kWh

2. Production Demand Charge:
   a. Winter Demand $7.28 per kW-month ($87.36 per kW-year)

   b. Summer Demand $7.29 per kW-month ($87.48 per kW-year)

   c. Base Demand $3.99 per kW-month

3. Transmission Charge:
   a. Transmission Demand $3.36 per kW-month ($40.32 per kW-year)

   b. Transmission Energy $0.00442 (4.42 mills) per kWh
.

4. Substation Charge:
   a. Substation Fixed
      1) Less than 7,500 kVa $500 per substation per month
      2) 7,500 kVa and greater $1,000 per substation per month

   b. Substation Demand $1.18 per kW-month ($14.16 per kW-year) of the highest one-hour kW peak registered at each substation during 2023.

The Production Energy Charge, Production Base Demand and Transmission Energy Charges are billed monthly based on actual usage. The Production Winter Demand Charge, Production Summer Demand Charge, Transmission Demand Charge Substation Fixed Charge and Substation Demand Charge are payable in twelve equal monthly payments.

B. Determination of Production Winter Demand and Production Summer Demand Billing Units:

1. Power Factor Adjustment. Participants shall at all times take and use power in such a manner that the power factor shall be as near 100 percent as practical. At the option of Northern when the power factor at any delivery point during any hour is less than 95 percent leading or lagging, the metered demands (winter, summer, transmission and substation) for said delivery point used

for billing purposes shall be increased by the ratio of .95 divided by the substation's power factor. The substation's power factor is calculated by using the substation's average power factor of those hours during the month where the kW is equal to or greater than 85% of the substation's monthly non-coincidental peak (NCP).

2. Production Winter Demand Method. After adjustment of winter metered demands in accordance with Section I, above, and Sections II, V and VI each Participant's April 1, 2024 to April 1, 2025 winter billing demand shall be the 2023/2024 adjusted winter coincidental metered peak demand.

The 2023/2024 winter coincidental metered peak demand shall be comprised of the average of three separate billing demand measurement (BDM) periods of 3 consecutive hours of coincidental demands occurring at the time of the Joint System highest system peak load periods taken on up to three separate days, if possible, and occurring between December 1 and the following April 1. Said peak coincidental demands are to be taken or determined from data recorded with full demand response/load management applied according to the then applicable Ripple Control Operating Guide, except that interruption of the loads in Category I (short-term interruptible loads) and not cycled Category II (medium-term interruptible loads) are delayed 75 and 45 minutes respectively into the billing period.

See Table on page 19 for the municipal systems' Production Winter Demand billing units for billing year April 1, 2024 to April 1, 2025.

3. Production Summer Demand Method. After adjustment of summer metered demands in accordance with Section I, above, and Sections II, V and VI each Participant's April 1, 2024 to April 1, 2025 summer billing demand shall be the 2023 adjusted summer coincidental metered peak demand.

The 2023 summer coincidental metered peak demand shall be comprised of the average of all hours of qualified coincidental demands occurring at the time of the Joint System highest system peak load and occurring between June 1 and the following October 1 when full demand response/load management is applied according to the then applicable Ripple Control Operating Guide.

See Table on page 19 for the municipal systems' Production Summer Demand billing units for billing year April 1, 2024 to April 1, 2025.

C. Determination of Production Base Demand Billing Units:

Production Base Demand billing units are based on the monthly average kW demand on purchased kWh energy for the month. Monthly average kW demand is calculated by dividing the kWh energy purchased during the month by the total hours in that said month.

D. Determination of Transmission Demand Billing Units:

The Transmission Demand Charge is based upon the average of the 12 monthly peak loads (12CP) recorded at the time of the Joint System's monthly peak load during the immediate previous calendar year.

See Table on page 20 for the municipal systems' Transmission Demand billing units for the billing year April 1, 2024 to April 1, 2025.

E. Determination of Number of Substations for Substation Fixed Charge:

With only those exceptions specifically approved by the Board of Directors, each metering point having one delivery voltage shall be considered one substation.

With only those exceptions specifically approved by the Board of Directors, Participants shall pay the monthly charge on substation delivery points completed after March 20, 1984, for not less than 100 months. Any new substations added will be included in the rate calculations in the billing month immediately successive to the month in which the substation is available for service.

A fixed charge will be assessed for each substation delivery point. Any combination of Minnkota Class A Members, Northern Municipal Power Agency (Northern) Participants, WAPA customers or others may combine their loads at a location to share substation fixed charges. In this instance, the fixed charge will be prorated among the users in proportion to their annual kWh usage the previous year. During the initial year of a new joint substation, an equitable proration of the substation fixed charge will be made from the best information available.

The following are exceptions to the delivery metering points when determining the Substation Fixed Charge.

Delivery metering points that are shared with a member cooperative.

- Bagley at Bagley, Minnesota
- Depuy at Grafton, North Dakota
- Fosston at Fosston, Minnesota
- Haslerud at Warroad, Minnesota
- Owen at Thief River Falls, Minnesota
- Park River at Park River, North Dakota
- Polaris at Roseau, Minnesota
- Roseau City at Roseau, Minnesota
- Warroad at Warroad, Minnesota

F. Determination of Substation Demand Billing Units:

The Substation Demand billing units are based upon the highest 2023 (calendar year) one-hour kW peak load at each delivery point. Substation peaks created by load switching at Northern's request for equipment maintenance and/or change-outs will be waived.

See Table on page 20 for the municipal systems' Substation Demand billing units for billing year April 1, 2024 to April 1, 2025.

Section II – Cogeneration Facility Energy Services

Cogeneration Facilities (also known as combined heat and power) must be a qualified facility as per the Public Utility Regulatory Policies Act (PURPA) of 1978 and Minnesota/North Dakota statutes and/or regulations.

A. Definitions:

1. Qualified Cogeneration Facility – defined as a facility which produces electric energy and steam or other forms of useful energy (such as heat) which is used for industrial, commercial, heating or cooling purposes and which complies with the efficiency and/or fuel source standards of the United States Federal Energy Regulatory Commission (FERC) Order No. 70.

2. Cogeneration Facility Standby Service – defined as electric capacity and energy provided by Northern to Participants for resale to consumers operating Cogeneration Facilities and is available for use only to maintain normal operation of said consumer's manufacturing or production facility during periods of emergency outage, emergency restriction of said consumer's electric generating facilities or planned outages approved by Northern.

3. Monthly Average Demand – defined as demand calculated by averaging each hourly kW demand of purchased energy within the calendar month.

B. Applicability:

Cogeneration Facility Standby Service will be made available by Northern to:

1. Participants for resale to consumer owner/operators of Cogeneration Facilities.

2. Consumer owner/operators of Cogeneration Facilities with permission of appropriate Participant.

The obligation of consumers to take or pay for firm electric service shall take precedence over use of said Cogeneration Facility Standby Service.

C. Rate Schedule (energy purchased by the municipal system/Cogeneration Facility):

1.	Production Energy Charge:		\$0.03594 (35.94 mills) per kWh for energy delivered to the Cogeneration Facility.
2.	Production Demand Charge:		
	a.	Winter Demand	\$7.28 per kW-month based on the monthly average demand on purchased energy.
	b.	Summer Demand	\$7.29 per kW-month based on the monthly average demand on purchased energy.
	c.	Base Demand	\$3.99 per kW-month based on the monthly average demand on purchased energy.
3.	Transmission Charge:		
	a.	Transmission Demand	\$3.36 per kW-month of transmission demand based on the monthly average demand on purchased energy.
	b.	Transmission Energy	\$0.00442 (4.42 mills) per kWh for energy delivered to the Cogeneration Facility.
4.	Substation Charge:		
	a.	Substation Fixed	
		1) Less than 7,500 kVa	\$500 per substation per month
		2) 7,500 kVa and greater	\$1,000 per substation per month
	b.	Substation Demand	\$1.18 per kW-month (\$14.16 per kW-year) of the highest one-hour kW peak registered at the Cogeneration Facility during 2023.
5.	Standby Service Charges:		See Subsection F below

The Production Energy Charge, Production Winter Demand Charge, Production Summer Demand Charge, Production Base Demand Charge, Transmission Demand Charge, Transmission Energy Charge and Standby Service Charges are billed monthly based on actual usage. The Substation Demand Charge and Substation Fixed Charge are payable in 12 equal monthly payments.

D. Determination of Production Winter Demand, Production Summer Demand, Production Base Demand and Transmission Demand Billing Units:

The billing units for Production Winter Demand Charge, Production Summer Demand Charge, Production Base Demand Charge and the Transmission Demand Charge are based on monthly average kW demand on purchased kWh energy for the month. Monthly average kW demand is calculated by dividing the kWh energy purchased during the month by the total hours in that said month.

E. Determination of Substation Demand Billing Units:

The Substation Demand billing units are based on the Cogeneration Facility's highest registered one-hour kW peak load for calendar year 2023.

F. Cogeneration Facility Standby Service Charges:

The Facility's generator(s) shall be metered by a time synchronized, continuous operation, one-hour or less interval demand recorder and capable of being metered on a five-minute interval basis as well as communicating real-time meter data to Minnkota's Energy Management System (EMS).

The charges of standby service provided to the municipal system/Facility by Northern shall be based on the Facility's generator(s) kW nameplate rating in alternating current (AC). However, upon a request by the Facility and with mutual agreement between Northern and the municipal system/Facility, the Facility's standby service kW amount may be lowered. The standby service charges will then be based on the requested standby service kW amount and Northern's obligation to provide standby service is set at such requested kW amount.

1. Standby Service Energy Charge. All energy delivered to the Facility, whether firm power above the generator(s) kW nameplate rating or standby service provided by Northern, will be charged based on the Cogeneration Facility Production Energy Charge as stated in Subsection C. – Rate Schedule above.

   An additional charge will be assessed and billed to the municipal system/Facility for each standby service energy kWh delivered to the Facility which is measured and billed on an hourly basis. The charge will be the incremental difference between Minnkota's average hourly real-time market rate per kWh for energy purchased during the hour times 105% and Cogeneration Facility Production Energy Charge as stated in Subsection C. – Rate Schedule above. If the incremental difference is negative for that hour, no Standby Service Charge will be charged to the municipal system/Facility for kWh delivered to the Facility.

2. Standby Service Production Resource Charges: This charge covers costs not addressed elsewhere in this rate for fixed costs, capacity costs, operating and maintenance costs, etc. for system production resource assets when those assets are primarily used for standby service purposes.

   Upon occurrences, the municipal system/Facility is responsible and will be charged any and all penalties, fees and costs from MISO (Midcontinent Independent System Operator) associated with inaccurate scheduling of load as well as any and all of Minnkota's settlement costs (as per MISO's tariff and future changes to MISO's tariff) including, but not limited to, miscellaneous energy charges, ancillary service market (ASM) charges, resource capacity costs and applicable MISO administration fees. This may occur with a planned or emergency shut down of the generator(s) or operating the generator(s) above or below the level the generator(s) were scheduled at MISO for said day.

3. Any and all planned outages must be coordinated and approved by Northern which will help avoid unnecessary charges to the municipal system/Facility.

4. Standby Service Transmission and Substation Charges. These monthly charges are based on the Facility's generator(s) kW nameplate rating in alternating current (AC) or mutually agreed upon request from the Facility for a lower standby service kW amount which represents the kW amount of the standby service being provided by Northern. The charges cover costs not addressed elsewhere in this rate for system energy losses, fixed costs, operating and maintenance costs, etc. for system transmission and substation assets when those assets are primarily used for standby service purposes.

   a. Transmission Demand Standby Service Charge: Charged monthly by multiplying the Facility's generator(s) kW nameplate rating (or requested standby kW) by 75% of the Transmission Demand Charge as stated in Subsection C. – Rate Schedule above.

      Example: 5,000 kW nameplate x (75% x $3.36 per kW-month) = $12,600.00 per month

   b. Transmission Energy Standby Service Charge: Charged monthly by multiplying the Facility's generator(s) kW nameplate rating (or requested standby kW) by the hours in the month and then by 75% of the Transmission Energy Charge as stated in Subsection C. – Rate Schedule above.

      Example: 5,000 kW nameplate x 744 hours x (75% x $0.00442 per kWh) = $12,331.80 for month

   c. Substation Demand Standby Service Charge: Charged monthly by multiplying the Facility's generator(s) kW nameplate rating (or requested standby kW) by the Substation Demand Charge as stated in Subsection C. – Rate Schedule above.

      Example: 5,000 kW nameplate x $1.18 per kW-month = $5,900.00 per month

   d. Credit: Any revenue generated from energy purchases during the month through the Transmission Demand Charge, Transmission Energy Charge and Substation Demand Charge will be credited back to the municipal system/Facility. The credit will not exceed the monthly standby charges for Transmission Demand, Transmission Energy and Substation Demand.

G. Northern's Payment for Excess Energy:

A meter will measure excess energy that flows back onto the distribution and/or transmission system. Excess energy is defined as kWh that is produced by the Facility's generator(s) and not consumed by the Facility's load at the time the said energy is being generated.

Northern will pay a negotiated rate for cogenerated electric energy that is in excess of the electric load required for operation of the Facility.

The excess energy that is purchased from the Facility and delivered to a municipal distribution system will be added to the municipal system's monthly wholesale power bill from Northern.

H. Demand Adjustment to Municipal System:

Since the Cogeneration Facility Energy Services Rate Schedule for purchased power charges the Production Winter Demand Charge, Production Summer Demand Charge and Transmission Demand Charge based on the monthly average demand on purchased energy, Northern will zero out the measured Production Winter Demand, Production Summer Demand and Transmission Demand billing units that the municipal system would normally pay during the billing year for the Cogeneration Facility.

Section III –Distributed Generation (DG)

A. Applicability:

This section addresses distributed generation (DG) facilities that are installed and interconnected on a municipal system's electric system and/or Northern's system.

B. Definitions:

1. Distributed generation (DG) – defined as small generation facilities (usually 10 MW or less) powered by fossil fuels or renewable energy sources that are grid-connected and located close to the electric load they serve.

2. Renewable energy source – defined as wind, solar, small hydro, biomass, geothermal, hydrogen, or recycled energy systems producing electricity from unused waste heat.

3. Net metered – defined as a retail electric account that has installed a renewable distributed generation (DG) facility with a nameplate less than 40 kW alternating current (AC) behind the utility's electric meter (load-side) that serves all or part of the entire account's domestic energy use when operating. At times, the DG generates kWh energy in excess of the electric energy required for domestic use causing the meter to literally or figuratively run backwards. The account is charged or credited the net difference between energy consumption and generation at the retail rate or avoided cost.

4. Net billed – defined as a retail electric account that has installed a renewable distributed generation (DG) facility with a nameplate less than 40 kW (AC) behind the utility's electric meter (load-side) that serves all or part of the entire account's domestic energy use when operating. The meter records all kWh energy delivered to the account by the municipal system and separately records the kWh energy produced by the DG facility not consumed by the account's load at the time the DG energy is generated – defined as excess kWh energy. The account is charged for the kWh energy delivered from the municipal system at the retail rate and is given a credit/payment for excess kWh energy generated by the DG facility at the retail rate or avoided cost.

5. Self-supply – defined as a retail electric account that has installed a distributed generation (DG) facility with a nameplate 40 kW (AC) and greater behind the utility's electric meter (load-side) that serves all or part of the entire account's domestic energy use when operating. The meter records all kWh energy delivered to the account by the municipal system and separately records the kWh energy produced by the DG facility and not consumed by the account's load at the time the DG energy is generated – defined as excess kWh energy. The account is charged for the kWh energy delivered from the municipal system at the retail rate and is given a credit/payment for excess kWh energy generated from the DG facility at Northern's avoided cost.

6. Excess renewable energy – defined as kWh energy generated by a retail electric account's renewable distributed generation (DG) facility in excess of the electric energy consumed by the account's own domestic energy use at the account's location.

C. Reimbursement / Payment for Distributed Generation (DG) Energy:

Category #1: Less than 40 kW alternating current (AC) Net Metered/Net Billed Renewable Distributed Generation (DG) Facility.

1. Requires an appropriate agreement with Northern consistent with applicable law and/or regulation.

2. Reimbursement / Payment to Minnesota Municipal Systems: Northern will reimburse the municipal system for "excess renewable energy" produced from a renewable distributed generation facility with nameplate capacity less than 40 kW.
   - After the calendar year, Northern will request individual distributed generation facility's monthly energy usage and energy generated data from the municipal system.
   - Reimbursement payment for "excess renewable energy" will be the difference between the municipal system's average rate per kWh for the customer class and Northern's average wholesale rate per kWh for the municipal system as per Minnesota statutes.

3. Reimbursement / Payment to North Dakota Municipal Systems: Northern will reimburse the municipal system for "excess renewable energy" produced from a renewable distributed generation facility with nameplate capacity less than 40 kW.
   - After the calendar year, Northern will request individual distributed generation facility's monthly energy usage and energy generated data from the municipal system.
   - Reimbursement payment for "excess renewable energy" will be made using the Distributed Generation Energy Rate (stated below in Category #2) which is Northern's avoided cost.

Category #2: Distributed Generation (DG) Facility.

1. Includes all DG facilities that do not qualify for Category #1 above.

2. Requires a Purchase Power Agreement (PPA) or a Self-Supply Agreement with Northern and/or municipal system.

3. Dedicated Meter Required: DG facility generator(s) must have a dedicated meter that is time synchronized, continuous operation, one-hour or less demand recorder and capable of being metered on a five-minute interval basis as well as communicating real-time meter data to Minnkota's Energy Management System (EMS).

4. Energy Rate: Northern will pay the generation facility for kWh generated and delivered to Northern. The distributed generation energy rate is Northern's avoided cost which is currently based on the wholesale energy market conditions and is the 2024 Budgeted off-system sales rate. The distributed generation energy rate is set for the 2024/2025 Wholesale Power Rate Schedule and is subject to change on an annual basis.

   Distributed Generation Energy Rate: $0.028 per kWh

   Adjustment to the distributed generation energy rate may be done on a case-by-case basis depending on the value the energy provides to Northern. The criteria considered include but are not inclusive to: the ability/limits to dispatch the generator(s), on-peak kWh production versus off-peak kWh production, the generator(s) capacity factor, Northern's needs for capacity and energy, etc. The adjustment will be a defined amount per kWh in the PPA and will be in addition to the stated distributed generation energy rate.

A renewable distributed generation facility located in Minnesota with a nameplate of 40 kW to 100 kW (AC) can request a "time-of-day purchase rate" from Northern under Minnesota Rule § 7835.3500 – Time-of-Day Purchase Rate. The time-of-day purchase rate will be based on Northern's avoided cost.

5. Self-Supply DG Facility Standby Service Charges: Through the municipal system, Northern will charge standby demand and energy service charges to a DG facility that self-supplies its electric account with its DG generation. The standby service charges shall be based on the DG facility's generator(s) kW nameplate rating in alternating current (AC). However, upon request by the DG facility and with mutual agreement with Northern and the municipal system/DG facility, the standby service kW amount may be lowered. The standby charges will then be based on the requested standby service kW amount and Northern's obligation to provide standby service is set at such requested kW amount. The charges vary with the fuel resource of the DG facility and its generator(s) kW nameplate rating or requested standby service kW amount.

Standby Demand (kW) Charge.

a. The standby demand charge helps cover a portion of the fixed costs of Northern's production, transmission and substation assets required to provide electric power to the DG facility when its generator(s) is not producing kWh energy at the generator(s) kW nameplate rating to adequately self-supply its account's electric load requirements.

b. The monthly charge is calculated by multiplying the DG facility's generator(s) kW nameplate rating (or requested standby service kW amount) by the appropriate standby demand rate shown in Appendix A on page 18. The monthly standby demand charge for DG facility's using biomass or fossil-fuel as its fuel source will be addressed on a case-by-case basis and will be based on the DG generator(s) projected generation capacity and generation profile.

c. The monthly standby demand charge may offset production, transmission and substation demand charges depending on the DG facility account's electric load and the performance of its generator(s).

Standby Energy (kWh) Charge.

a. When a DG facility is not producing kWh energy at its generator(s) kW nameplate rating (or requested standby service kW amount), Northern, through the municipal system, will provide kWh energy needed to meet the DG facility's electric load requirements not supplied by their DG facility generator(s) – this is called standby energy.

b. Standby Energy Calculation. The monthly standby kWh energy is measured on an hourly basis. It is calculated by using the lesser of either (1) the DG facility's generator(s) kW nameplate rating (or requested standby service kW amount), or (2) the DG facility's hourly kWh energy usage during the month to meet its electric load requirements, less the kWh energy produced by the DG facility's generator(s) for each respective hour during the month.

c. Monthly Average Cost Calculation. The standby energy measured each hour of the month is multiplied by Minnkota's average hourly real-time market price per kWh for the respective hour. The accumulative dollar amount for each hour of the month is then divided by the total number of standby kWh purchased during the month.

d. Cost Allocation Determinative. If the monthly average cost per standby kWh is less than Northern's current Production Energy Charge (rate) per kWh (page 1), there is no standby energy charge. However, if the monthly average cost per standby kWh is higher than the Production Energy Charge (rate), the incremental price difference will be charged to each standby energy kWh metered during that month.

Excess kWh Energy Payment.

a. The excess kWh energy is measured on an hourly basis and is kWh energy produced by the DG facility generator(s) and not consumed by the facility's electric load at the time the energy is generated. Northern will pay, through the municipal system, for the excess kWh energy.

b. Excess kWh Energy Payment Below Nameplate (or Requested Standby Service). Excess kWh energy metered below the DG facility's kW nameplate rating (or requested standby service kW amount) during the month will be multiplied by the higher of either (1) Northern's Distributed Generation Energy Rate (page 8), or (2) the monthly average price per excess kWh energy using real-time market prices (detailed below in subsection d.).

c. Excess kWh Energy Payment Above Nameplate (or Requested Standby Service). Any excess kWh energy metered above the DG facility's kW nameplate rating (or requested standby service kW amount) during the month will be multiplied by the lesser of either (1) Northern's Distributed Generation Energy Rate (page 8), or (2) the monthly average price per excess kWh energy using real-time market prices (detailed below in subsection d.).

d. Monthly Average Price Calculation. The monthly average price per excess kWh energy is calculated by multiplying the excess kWh energy measured each hour of the month by Northern's average hourly real-time market price per kWh for the respective hour. The accumulative dollar amount for each hour of the month is then divided by the total number of excess kWh energy delivered to Northern during the month.

e. The excess kWh energy that is purchased from the DG facility and delivered to a municipal distribution system will be added to the municipal system's monthly wholesale power bill from Northern.

Section IV – MISO (Midcontinent Independent System Operator) Generation Accreditation & Capacity Credit

A. Qualifications:

1. Accreditation is done on a case-by-case basis upon request and a generation facility must meet the following criteria as per current MISO tariff language for resource adequacy accreditation to receive a capacity credit:

    a. Individual generator(s) shall be 100 kW or larger.

b. Generation must be connected synchronously to Northern's transmission system and/or municipal’s distribution system.

c. Must be metered by a time synchronized, continuous operation, one-hour or less demand recorder and capable of being metered on a five-minute interval basis.

d. Annually perform a test of the generation at maximum output and submit the results to Northern.

e. Generator(s) must be capable of operating a minimum of four consecutive hours and a minimum of ten annual events and meet minimum seasonal performance requirements as outlined in the MISO tariff.
   - Must have a notification time of less than six hours.
   - Must respond to first five deployment requests in summer and winter seasons.
   - Must respond to first three deployment requests in spring and fall seasons.
   - Generation facility is responsible for any penalty charged by MISO if its generator(s) does not operate at the set performance level.

f. Provide Northern with generation performance data, upon request.

g. Maintain generator(s) in condition that meets good utility practice.

h. The generator(s) must be dispatchable and Northern retains the right to dispatch the generator(s) as needed.

i. Enter into a contractual agreement with the Participant and/or Northern.

j. Other MISO qualifications that may be assessed to a specific generator(s).

2. The Participant must allow the customer and Northern to utilize its distribution facilities to facilitate the transfer of power from the generator(s) to and from Northern.

3. Requires a contract agreement with Northern.

B. Capacity Credit:

1. Generation facility not supplying their load needs: Northern will pay the generation facility $21.00 per kW per year ($1.75 per kW per month) for MISO accredited generation.
2. Generation facility supplying their load needs: Northern will pay the generation facility $21.00 per kW per year ($1.75 per kW per month) for MISO accredited generation that is in excess of 115% of the customer’s one-hour kW peak load.

3. The capacity credit is reviewed annually and is subject to change on an annual basis.

Section V – Inadvertent Demand Adjustment (IDA)

This program is an option for generator Incremental Pricing Plan (IPP) accounts to offset possible financial losses caused by the malfunction of load management facilities during billing demand measurement (BDM) periods. The program can mitigate the impact of large unanticipated inadvertent wholesale power demand billings on the Participant’s system and/or its larger commercial and industrial consumers which are metered with recording demand meters. In the case of multiple generators at the same site, the individual load associated with each generator must be qualified separately.

A. Qualifications

1. Each load must meet the following criteria:

a. Must have an adequately installed and properly maintained directly connected automatic load control system.

b. Must be metered by a time synchronized, continuous operation, one hour or less interval, demand recorder and capable of being metered on a five-minute interval basis.

B. Rate Schedule

1. The Participant must pay Northern for the kW level of each selected qualified load that could increase the Participant's seasonal billing demand should load management fail to curtail the insured load(s).

Season	**Rate**	**Payment Due Date**
Summer 2024	$2.19/kW	May 15, 2024
Winter 2024/2025	$2.18/kW	November 15, 2024

2. The Participant shall supply the name of each qualified load and the estimated kW demand of each load along with the payment in accordance with the rate schedule above.

C. Inadvertent Demand Adjustment (IDA) Credit

1. Upon acceptable demonstration by the Participant of the magnitude of kW of qualified load that failed to be controlled, Northern will subtract from the Participants affected hourly metered seasonal demand coincidental production demands used for summer and winter billing demand. The credit calculation is the kW amount equal to 1.08 x 0.667 times any portion of the qualified load which inadvertently and unintentionally became a demand obligation through human error or failure of load control equipment located at the load site.

2. Northern and the municipal system have the right to disqualify a generator account that has multiple system failures during load control events.

Section VI – Demand Response Program

The demand response program is available to Participants in two categories: Standard Demand Response and Incremental Pricing Plan (IPP) Demand Response.

A. Standard Demand Response

1. Qualifications

a. Available to off-peak installations of dual fuel heating, storage heating, water heating, air conditioning, electric transportation charging, electric warehouse/construction equipment charging, irrigation, electric grain drying/handling systems, commercial loads, dispatchable generators or other approved loads by Northern.

i. Dual fuel heating and storage heating installations must have adequate, qualified back-up heating systems.

ii. To participate in any demand response programs, generator(s) must meet all applicable federal, state and local regulations. As an example, the EPA requires a generator(s) (no matter the horsepower size or the kilowatt generation capacity) under a demand response program to be a stationary installation and be RICE (Reciprocating Internal Combustion Engine) Rule complaint.

b. Installations must be controlled with a load control receiver programed with the proper double order code as documented in the Ripple Operating Guide that assures that the off-peak load is properly controlled during all load control events.

2. Control/Operational Criteria

a. Standard demand response off-peak accounts must curtail its load during all load control events. Load control will be required and initiated when:

i. Northern is reaching a capacity limit.

ii. MISO (Midcontinent Independent System Operator) hourly market prices are high.

iii. Billing demand measurement (BDM) periods are initiated to establish Production Winter Demand and Production Summer Demand billing units.

iv. Load control is initiated for performance measurement used in MISO capacity accreditation.

v. Declared MISO events/emergencies and/or Northern system events/emergencies.

B. Incremental Pricing Plan (IPP) Demand Response

1. <u>Qualifications</u>

a. Available to irrigation, Heating Demand Waiver (HDW) generators, commercial loads (includes dispatchable generator(s), production processes, etc.), or qualified loads approved Northern that may choose to pay a supplemental payment in lieu of load control or generation during certain load control events.

i. To participate in any demand response programs, generator(s) must meet all applicable federal, state and local regulations. As an example, the EPA requires a generator(s) (no matter the horsepower size or the kilowatt generation capacity) under a demand response program to be a stationary installation and be RICE (Reciprocating Internal Combustion Engine) Rule complaint.

b. Each commercial load or HDW generator must be metered by a time synchronized, continuous operation, one-hour or less interval demand recorder and capable of being metered on a five-minute interval basis.

c. Individual commercial loads that participate must be controlled with a load control receiver programed with the proper double order specific to the Incremental Pricing Plan (IPP) as documented in the Ripple Operating Guide.

d. Each HDW generator must be capable of being MISO accredited as Northern generation in both the summer and winter seasons. The HDW generators would be run under Northern's control and discretion similar to other Northern MISO accredited generation.

2. Control/Operational Criteria

a. The commercial double orders specific to the Incremental Pricing Plan (IPP) will not be controlled unless:

i. Load control is required because Northern is reaching a capacity limit.

ii. Northern is buying energy and the wholesale market price for that purchased energy would lead to an average purchased energy price greater than the pre-determined average for that season.

iii. Load control is required for Schedule L certification.

iv. Billing demand measurement BDM periods are initiated to establish Production Winter Demand and Production Summer Demand billing units.

v. Declared MISO events/emergencies and/or Northern system events/emergencies.

b. The HDW generators will be considered in the HDW yellow zone, when a supplemental energy payment can be made in lieu of operation, for the same number of hours as the seasonal average control hours of the dual fuel furnaces.

c. Northern will, during HDW yellow zone time periods, purchase energy from the wholesale market in a quantity equal to the lower of the total generation accredited capability or the HDW customer load. The energy quantity will be agreed to prior to the start of a winter season. Energy will be purchased at an average winter season price that will be equal to the IPP commercial customer price.

3. Data Reporting

a. Each Participant in this program will report the hourly coincidental metered demand data and energy data for each qualifying commercial customer for all load control hours normally scheduled for that load as follows:

Season	Demand Data	Supplemental Energy Data
Winter	3/10/2024	5/1/2024
Summer	11/15/2024	11/15/2024

4. Rate Schedule

a. The Participant must pay Northern a supplemental charge of up to 12¢/kWh for commercial loads for kWh recorded on the hourly coincidental meter(s) during all load control events normally scheduled for the qualifying commercial customer(s). The recorded kWh will start at the beginning of the clock quarter hour after activation begins and ending at the beginning of the clock quarter hour before the activation ends.

b. The Participant must pay Northern a supplemental charge of up to 12¢/kWh for the quantity of KWHs calculated as the HDW yellow zone periods (same number of hours as the seasonal average of the dual fuel furnaces) times the lower of the total generation accredited capability or the HDW customer load calculated as if the program continued to exist.

5. Metered Demand Credit

a. Northern will credit each Participant's hourly winter and summer coincidental billing demand based on the hourly metered demand supplied in Paragraph C above except for the hours when control is required for capacity limitation, to avoid higher cost energy purchases or Schedule L certification as defined in Paragraph B above.

b. Northern will credit each Participant's hourly winter coincidental billing demand for HDW generation by the lesser of:

i. The effective MISO accredited generation level of the generators, or

ii. The total load attributable to the Participant's demand waiver customers who would have been eligible for the Demand Waiver Program had that program continued to exist after March 2005.

6. HDW Generator Fuel Pricing

a. Northern will pay each Participant when Northern operates the HDW generation for its own purpose at a rate of the actual fuel cost plus 25%.

Section VII – General

A. Feasibility of New or Expanded Substation Delivery Points:

1. Dedicated Substation. If normal revenue expected to be derived from a new or expanded dedicated substation delivery point for a large commercial/industrial load is projected to not adequately cover ownership and operating costs over a reasonable length, Northern, on a case-by-case basis, may require a minimum substation and demand charge, a contribution in aid of construction, minimum annual revenue requirement or other special arrangement to assure an adequate return on the required facility investment.

2. General Service Substation. A request for a new or expanded substation delivery point that does not meet Northern's need/justification standards (example: requested before Northern would normally construct such substation delivery point) may be constructed under the general provisions that include:

a. Northern would design, construct, own and maintain the facility.

b. To assure an adequate return of facility investment, Northern and the requesting Participant(s) will enter into an appropriate agreement of one of the following options:

1. Contribution in aid of construction

2. Minimum annual revenue requirement

- The cost of the new facilities would be amortized over 33 years at the then current borrowing rate. This value becomes the minimum annual revenue requirement and is divided by 12 to become the minimum monthly revenue requirement.
- Beginning the first month following energization and each month thereafter, Northern will bill the requesting Participant for the difference between the minimum monthly revenue requirement and the then current monthly fixed substation charge until such time the new facilities meet the Northern need/justification standards.
- Northern will determine the load level that would meet the Northern need/justification standards prior to construction of the requested facilities.

3. Other special arrangement

B. Service Conditions:

Northern reserves the right to require Participants to correct any condition on its system or on the systems of its customers which causes a hazard to Joint System facilities and personnel, or to the quality of service provided by Northern or Minnkota to others. All motors, appliances or equipment connected to the Participant's systems must be so designed, installed and operated as not to cause undue disturbance to others nor to handicap Northern and Minnkota in maintaining proper system conditions. The Minnkota Generation & Transmission & End Use Interconnection Requirements will be applied to determine acceptable system impacts.

Section VIII – Infinity Renewable Energy Program

This program provides Northern municipal systems the source to purchase renewable energy for resale to their customers. In most cases that will be done through the purchase of renewable energy credits (RECs) or green tags. The RECs will be sold on a per kWh basis and are M-RETS (Midwest Renewable Energy Tracking System) certified. Once sold, the RECs are retired in M-RETS, which means they cannot be used or claimed again.

The purchase of renewable energy kWh is on a monthly basis and is billed to the participating municipal system one month in the arrears. At the end of each month, the municipal system is responsible for calculating the actual quantity of renewable energy kWh they sold to their customers. The municipal system must submit the quantity of the kWh they need to purchase from Northern to cover the renewable energy kWh sold to their customers by the 10th of the following month. The charge for those kWh will be on the municipal system's next monthly power bill.

A. Wind Energy: The renewable energy kWh will be priced and reported by the municipal system in two categories. The customer must commit to the pricing of one category for the entire billing year.

Category #1: Fixed pricing for the April 1, 2024 to April 1, 2025 billing year.

- Wind Renewable Energy Fixed Charge: $0.0035 per kWh

Category #2: Variable pricing for the April 1, 2024 to April 1, 2025 billing year.

- Wind Renewable Energy Variable Charge: average monthly REC market price per kWh

- The variable charge has a floor price of $0.00075 per kWh and the renewable energy kWh will not be priced below the floor price.

B. Solar Energy: Solar energy pricing will be addressed on a case-by-case basis when a municipal system customer has an interest in purchasing solar energy.

C. Other Renewable Energy: At this time, the pricing of any other source of renewable energy will be addressed on a case-by-case basis when a municipal system customer has interest in purchasing such renewable energy.

Appendix A

Self-Supply Distributed Generation (DG) Facility

Wholesale Power Bill Rate Schedule

Standby Demand Charge

Rate Component		Solar	Wind
Standby Demand Charge	per kW-month	$8.40	$12.34

Charges BELOW DG Nameplate kW Rating

Rate Components		Solar	Wind
Energy	per kWh	$0.03594	$0.03594
Winter Demand	per kW-month	$7.28	$5.68
Summer Demand	per kW-month	$7.29	$5.69
Base Demand	per kW-month	n/a	n/a
Transmission Demand	per kW-month	$3.36	$2.62
Transmission Energy	per kWh	n/a	n/a
Substation Demand	per kW-month	n/a	n/a

Charges ABOVE DG Nameplate kW Rating

Rate Components		Solar	Wind
Energy	per kWh	$0.03594	$0.03594
Winter Demand	per kW-month	$7.28	$7.28
Summer Demand	per kW-month	$7.29	$7.29
Base Demand	per kW-month	$3.99	$3.99
Transmission Demand	per kW-month	$3.36	$3.36
Transmission Energy	per kWh	$0.00442	$0.00442
Substation Demand	per kW-month	$1.18	$1.18

Production Winter Demand Billing Units

(April 1, 2024 to April 1, 2025)

Municipal	2023/2024 Winter Demand	Demand Adjustments	Billing Demand
Bagley	3,048.7	0.0	3,048.7
Baudette	2,559.3	0.0	2,559.3
Fosston	4,166.7	0.0	4,166.7
Grafton	6,958.3	0.0	6,958.3
Halstad	1,302.3	0.0	1,302.3
Hawley	2,758.7	0.0	2,758.7
Park River	3,248.7	0.0	3,248.7
Roseau	5,221.3	0.0	5,221.3
Stephen	919.3	0.0	919.3
Thief River	19,228.7	0.0	19,228.7
Warren	2,511.7	0.0	2,511.7
Warroad	4,509.0	(30.5)	4,478.5
Totals	56,432.7	(30.5)	56,402.2

Production Summer Demand Billing Units

(April 1, 2024 to April 1, 2025)

Municipal	2023 Summer Demand	Demand Adjustments	Billing Demand
Bagley	3,869.8	(68.1)	3,801.7
Baudette	3,087.8	0.0	3,087.8
Fosston	4,172.5	(32.5)	4,140.0
Grafton	8,294.7	(1,068.1)	7,226.5
Halstad	932.8	0.0	932.8
Hawley	3,771.3	(260.1)	3,511.2
Park River	3,429.7	0.0	3,429.7
Roseau	6,412.1	(5.2)	6,406.9
Stephen	1,127.8	0.0	1,127.8
Thief River	24,358.7	(424.6)	23,934.1
Warren	3,327.0	0.0	3,327.0
Warroad	8,503.3	(998.0)	7,505.3
Totals	71,287.3	(2,856.6)	68,430.7

Transmission Demand Billing Units
(April 1, 2024 to April 1, 2025)

Municipal	2023 12 Coincidental Peak (12 CP)	Demand Adjustments	Billing Demand
Bagley	3,737.0	0.0	3,737.0
Baudette	2,961.0	0.0	2,961.0
Fosston	4,440.0	0.0	4,440.0
Grafton	8,328.0	0.0	8,328.0
Halstad	1,346.0	0.0	1,346.0
Hawley	3,685.0	0.0	3,685.0
Park River	3,233.0	0.0	3,233.0
Roseau	5,784.0	0.0	5,784.0
Stephen	1,193.0	0.0	1,193.0
Thief River	22,205.0	0.0	22,205.0
Warren	2,911.0	0.0	2,911.0
Warroad	9,838.0	0.0	9,838.0
Totals	69,661.0	0.0	69,661.0

Substation Demand Billing Units
(April 1, 2024 to April 1, 2025)

Municipal	2023 Substation Demand	Demand Adjustments	Billing Demand
Bagley	4,750.0	0.0	4,750.0
Baudette	3,511.0	0.0	3,511.0
Fosston	5,335.0	0.0	5,335.0
Grafton	11,545.0	0.0	11,545.0
Halstad	2,139.0	0.0	2,139.0
Hawley	4,661.0	0.0	4,661.0
Park River	3,897.0	0.0	3,897.0
Roseau	7,442.0	0.0	7,442.0
Stephen	1,757.0	0.0	1,757.0
Thief River	29,580.0	0.0	29,580.0
Warren	3,892.0	0.0	3,892.0
Warroad	12,643.0	0.0	12,643.0
Totals	91,152.0	0.0	91,152.0

EXHIBIT F

NORTHERN MUNICIPAL POWER AGENCY
BLENDED WHOLESALE POWER COSTS
January Thru December, 2024

	kWh Usage	Wholesale Power/Delivery Cost	NMPA Levy Cost	Total Cost	Mills /kWh	Increase (Decrease) over 2023 Mills/kWh
Bagley	24,270,066	$1,949,351.46	$2,427.02	$1,951,778.48	80.42	0.98
Baudette	20,163,935	$1,599,205.45	$2,016.39	$1,601,221.84	79.41	(0.72)
Fosston	30,722,721	$2,386,904.14	$3,072.27	$2,389,976.41	77.79	1.59
Grafton	51,583,394	$4,116,175.41	$5,158.33	$4,121,333.74	79.90	1.57
Halstad	7,436,961	$628,248.03	$743.71	$628,991.74	84.58	3.15
Hawley	20,591,222	$1,719,898.21	$2,059.13	$1,721,957.34	83.63	2.33
Park River	18,888,457	$1,637,234.39	$1,888.85	$1,639,123.24	86.78	3.17
Roseau	37,010,252	$3,063,754.98	$3,701.00	$3,067,455.98	82.88	0.05
Stephen	6,967,399	$580,893.64	$696.73	$581,590.37	83.47	2.63
Thief River Falls	140,672,520	$11,583,666.26	$14,067.23	$11,597,733.49	82.44	2.19
Warren	17,002,173	$1,471,407.48	$1,700.23	$1,473,107.71	86.64	1.78
Warroad	67,077,611	$4,728,497.13	$6,707.77	$4,735,204.90	70.59	0.22
TOTAL:	**442,386,711**	**$35,465,236.58**	**$44,238.66**	**$35,509,475.24**	**80.27**	**1.43**

EXHIBIT G

COYOTE GENERATING PLANT

2024 MONTHLY UTILIZATION
414,588 MW

Month	Gross Generation		Capacity Factor
January	299,010,570	kWh	88.43%
February	162,612,140		50.80%
March	241,100,980		71.16%
April	185,420,130		55.89%
May	114,332,830		32.95%
June	208,798,720		63.15%
July	251,268,560		73.94%
August	200,396,230		58.35%
September	103,317,800		30.61%
October	148,016,110		42.74%
November	223,790,330		67.71%
December	229,398,940		67.23%
TOTAL ANNUAL:	2,367,463,340	kWh	58.67%

Plant was connected to load for 7,623.52 hours during 2024, for an availability factor of 87.34%.

PAST 5 YEAR PERFORMANCE

Year	2020	2021	2022	2023	2024
Capacity Factor	63.46%	65.63%	60.32%	68.75%	58.67%
Availability Factor	91.35%	87.14%	75.84%	89.51%	87.34%

EXHIBIT H

COYOTE GENERATING PLANT

STATEMENT OF COSTS
January Thru December, 2024

MONTH	NET kWh GENERATED*	TOTAL COSTS	NMPA-kWh	NMPA-COSTS
January	281,019,570	$8,059,780.80	85,473,486	$2,440,382.79
February	152,104,230	$7,125,249.89	46,204,591	$2,151,839.16
March	226,139,960	$7,589,334.01	68,556,935	$2,294,593.12
April	171,912,450	$8,653,022.96	52,847,633	$2,627,727.85
May	106,480,860	$8,725,511.94	32,597,523	$2,642,163.71
June	194,221,320	$8,153,513.92	58,711,752	$2,460,528.74
July	235,369,500	$7,428,679.02	70,921,042	$2,235,490.55
August	185,457,300	$7,563,241.81	55,251,422	$2,259,221.73
September	95,410,940	$6,095,924.32	28,448,932	$1,823,360.12
October	137,150,910	$8,821,289.44	41,589,868	$2,665,319.38
November	208,539,390	$8,464,593.53	63,804,469	$2,581,087.61
December	214,309,350	$8,237,053.72	64,725,031	$2,482,272.49
TOTALS	2,208,115,780	$94,917,195.36	669,132,684	$28,663,987.25
Average Cost in Mills/kWh =		42.99		42.84

*Net of Regulation

EXHIBIT I

COYOTE GENERATING PLANT

ADVANCED FUNDS
January Thru December, 2024

FUNDING PERIOD	NMPA SHARE	TOTAL
January Advance	$2,387,281	$8,400,000
February Advance	$2,490,756	$8,200,000
March Advance	$2,542,449	$8,400,000
April Advance	$2,444,264	$8,100,000
May Advance	$2,567,793	$8,500,000
June Advance	$2,581,821	$8,500,000
July Advance	$3,054,510	$10,100,000
August Advance	$2,804,475	$9,300,000
September Advance	$2,286,887	$7,600,000
October Advance	$2,180,249	$7,300,000
November Advance	$1,944,583	$6,500,000
December Advance	$2,778,933	$9,200,000
Totals Advanced:	$30,064,001	$100,100,000

EXHIBIT J

NORTHERN MUNICIPAL POWER AGENCY, INC.

STATEMENT OF REVENUES AND COSTS
For the Years Ended December 31, 2024, 2023, 2022, 2021, 2020, and 2019

	2024	2023	2022	2021	2020	2019
REVENUES:						
Members	$35,509,475	$35,677,609	$35,765,029	$35,162,673	$34,709,684	$35,229,641
Minnkota Power Coop.	$1,596,161	NA	NA	NA	$18,306,901	$23,246,220
Other Public Authorities	NA	NA	NA	NA	NA	NA
Investment and Other Income	NA	NA	NA	NA	NA	NA
Exempt Sales to Public Authority and Other Income	$14,757,937	$16,638,325	$22,126,662	$15,001,069	$6,931,855	$9,375,136
Total	**$51,863,573**	**$52,315,934**	**$57,891,691**	**$50,163,742**	**$59,948,440**	**$67,850,997**
COSTS:						
Plant Operations						
Fuel	$19,565,959	$19,055,147	$19,098,239	$17,832,065	$18,081,650	$17,996,427
Operation and Maintenance	$8,898,541	$9,489,617	$12,519,200	$7,314,686	$7,883,190	$16,193,681
Transmission						
Operations	$1,758,133	$1,520,067	$1,627,524	$1,308,491	$1,507,923	$1,437,240
Maintenance	$1,602,616	$1,715,768	$1,573,242	$1,705,091	NA	NA
Purchased Power	$8,144,600	$7,546,186	$9,790,074	$7,123,197	NA	NA
Operating Agent Fee	$709,305	$1,070,328	$1,430,601	$1,969,110	$693,739	$670,460
Administrative Expense	$1,143,159	$1,090,965	$1,031,705	$749,413	NA	NA
Depreciation	$6,420,000	$7,635,000	$7,265,000	$8,210,000	$26,505,000	$25,025,000
Subtotal	**$48,242,313**	**$49,123,078**	**$54,335,585**	**$46,212,053**	**$54,671,502**	**$61,322,808**
Debt Service Interest	$3,621,260	$3,192,856	$3,556,106	$3,951,689	$5,276,938	$6,528,189
Total	**$51,863,573**	**$52,315,934**	**$57,891,691**	**$50,163,742**	**$59,948,440**	**$67,850,997**

Credit: Brady, Martz & Associates, P.C., Audit Reports

March 20, 2025

Minnkota Power COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

February 5, 2025

Northern Municipal Power Agency
Mr. Jasper Schneider
123 2nd St. W.
Thief River Falls, MN 56701-1912

Subject: Capital Credit Allocation of ***2024*** Operating Margin

Dear Mr. Schneider:

Northern Municipal Power Agency's share of Minnkota's capital credit allocation for ***2024*** is $17,559 (see attached Schedule 1).

This allocation is based on Minnkota's 2024 operating margin.

Also attached is a Statement of Capital Credit Allocations showing the 2024 allocation to your cooperative and the total accumulated capital credit allocation balance.

If you have any questions, don't hesitate to call me at (701) 795-4258.

Sincerely,
MINNKOTA POWER COOPERATIVE, INC.

Melanie Skjoiten

Melanie Skjoiten
Accounting Services Supervisor

Enclosure

Minnkota Power Cooperative
Capital Credit Allocation of 2024 Operating Margin
December 31, 2024
Schedule 1

Joint System Members	2024 Revenue	Margin Allocation
Beltrami	$ 39,366,079	$ 182,813
Cass	111,022,767	515,581
Cavalier	2,785,480	12,936
Clearwater-Polk	7,105,864	32,999
Nodak	89,518,414	415,717
North Star	8,686,518	40,340
PKM	9,614,042	44,647
Red Lake	9,822,027	45,613
Red River	9,899,450	45,972
Roseau	11,252,445	52,255
Wild Rice	22,318,250	103,644
NMPA	3,781,160	17,559
Total	$ 325,172,496	$ 1,510,076
		(A)

(A) ***Capital Credit Calculation***

Minnkota total margin for 2024	$ 9,255,066
Less non-operating margins	(7,744,990)
Minnkota operating margin allocated for 2024	$ 1,510,076

Statement of Capital Credit Allocations by Company
As of 12/31/2024

	Year	Annual Allocation	Accumulated Allocation	Annual Retirement	Accumulated Retirements	Balance
B-NO100	**Northern Municipal**					
	1998	37,001.00	37,001.00			37,001.00
	1999	91,065.00	128,066.00			128,066.00
	2000	187,182.00	315,248.00			315,248.00
	2001	186,758.00	502,006.00			502,006.00
	2002	27,898.00	529,904.00			529,904.00
	2011	92,167.00	622,071.00			622,071.00
	2012	293,947.31	916,018.31			916,018.31
	2013	77,610.24	993,628.55			993,628.55
	2014	24,748.32	1,018,376.87			1,018,376.87
	2019	3,231.00	1,021,607.87			1,021,607.87
	2020	702,771.00	1,724,378.87			1,724,378.87
	2021	1,766,105.00	3,490,483.87			3,490,483.87
	2022	146,187.00	3,636,670.87			3,636,670.87
	2023	71,459.00	3,708,129.87			3,708,129.87
	2024	17,559.00	3,725,688.87			3,725,688.87
	Account Totals	3,725,688.87		0.00	0.00	

EXHIBIT L

2023 Member Revenue Per MWh

1	37.20	PNGC Power
2	41.26	Sunflower
3	48.08	Deseret
4	51.03	Golden Spread
5	53.92	Associated
6	56.30	Sho-Me Power
7	56.86	Nebraska
8	57.48	Arkansas
9	58.07	Rushmore
10	58.32	Western Farmers
11	59.44	Oglethorpe
12	59.97	Chugach
13	60.04	Basin
14	61.17	East River
15	61.46	Central Electric - MO
16	61.74	Central Power - ND
17	61.87	Northeast Missouri
18	61.88	M & A Electric
19	62.10	Northwest Iowa
20	62.14	N. W. Electric
21	63.32	KAMO
22	63.46	Square Butte
23	64.80	Central Iowa
24	64.96	Arizona
25	65.00	East Texas
26	66.52	Corn Belt
27	68.93	Wolverine
28	69.80	NTEC
29	69.97	South Texas
30	71.06	Rayburn
31	71.48	Kansas Electric
32	72.47	North Carolina
33	72.57	Dairyland
34	73.04	SECI
35	73.10	Tri-State
36	73.70	Allegheny
37	75.52	Central Electric - SC
38	76.21	Minnkota
39	77.05	Wabash Valley
40	78.14	Cooperative Energy
41	78.15	East Kentucky
42	79.61	Great River
43	81.03	Big Rivers
44	81.93	Buckeye
45	82.19	PowerSouth
46	82.35	Southern Illinois
47	86.22	Hoosier
48	86.68	Old Dominion
49	88.41	Prairie Power
50	96.57	Brazos
51	127.07	San Miguel
52	364.69	KIUC

The Membership Average for this Ranking is: 74.54

Note: Member Information Excluded if No Data Available or Category N/A

EXHIBIT M

TABULATION DEGREE DAYS
GRAND FORKS, NORTH DAKOTA

	Degree Days													
	January	February	March	April	May	June	July	August	September	October	November	December	Annual	Average
1990	1,449	1,402	1,128	766	383	136	70	68	266	681	1,103	1,720	9,172	9,552
1991	1,835	1,283	1,157	618	279	64	68	51	333	834	1,336	1,489	9,347	9,532
1992	1,526	1,297	1,092	788	304	199	166	175	368	708	1,179	1,746	9,548	9,533
1993	1,793	1,528	1,210	716	368	212	118	126	425	801	1,243	1,597	10,137	9,584
1994	2,133	1,686	1,117	723	324	109	112	151	277	601	1,020	1,455	9,708	9,593
1995	1,704	1,522	1,211	884	436	100	81	75	372	762	1,366	1,722	10,235	9,639
1996	2,055	1,579	1,504	934	498	142	93	68	361	730	1,477	1,839	11,280	9,748
1997	1,977	1,459	1,402	869	543	81	96	110	268	716	1,254	1,287	10,062	9,768
1998	1,700	1,105	1,275	569	294	205	56	35	249	668	1,144	1,573	8,873	9,715
1999	1,833	1,255	1,138	670	392	143	54	109	440	725	935	1,377	9,071	9,680
2000	1,731	1,271	1,001	764	381	220	59	92	386	677	1,216	1,986	9,784	9,685
2001	1,585	1,656	1,239	735	390	198	43	73	363	792	910	1,457	9,441	9,673
2002	1,573	1,216	1,471	828	566	120	25	114	289	969	1,191	1,426	9,788	9,678
2003	1,714	1,636	1,326	692	408	160	63	53	365	665	1,295	1,444	9,821	9,685
2004	1,960	1,454	1,177	757	589	258	138	251	324	719	1,023	1,574	10,224	9,708
2005	1,905	1,425	1,246	609	505	116	68	126	270	680	1,080	1,463	9,493	9,699
2006	1,308	1,575	1,239	567	370	98	25	68	357	827	1,116	1,388	8,938	9,669
2007	1,675	1,653	1,158	740	356	104	47	119	325	635	1,128	1,720	9,660	9,669
2008	1,822	1,698	1,338	742	413	109	17	24	225	588	1,071	1,940	9,987	9,680
2009	2,038	1,569	1,346	740	432	149	47	66	77	771	894	1,793	9,922	9,689
2010	1,778	1,576	990	466	290	69	0	21	283	526	1,145	1,749	8,893	9,662
2011	1,989	1,555	1,405	714	364	68	4	6	208	477	998	1,319	9,107	9,643
2012	1,499	1,326	829	560	250	42	0	25	256	708	1,139	1,630	8,264	9,599
2013	1,734	1,509	1,566	985	336	113	29	52	132	689	1,208	2,008	10,361	9,622
2014	1,973	1,799	1,455	824	367	46	29	25	192	577	1,321	1,452	10,060	9,636
2015	1,622	1,699	1,047	611	373	58	14	50	142	523	936	1,388	8,463	9,601
2016	1,669	1,195	889	724	221	54	12	16	168	556	716	1,604	7,824	9,550
2017	1,641	1,256	1,155	623	267	45	8	11	179	564	1,223	1,655	8,627	9,525
2018	1,697	1,653	1,252	950	221	27	1	43	301	832	1,362	1,538	9,877	9,534
2019	1,945	1,883	1,468	717	431	76	9	41	211	775	1,190	1,718	10,464	9,559
2020	1,714	1,513	1,282	874	396	42	1	18	238	238	1,030	1,359	8,705	9,537
2021	1,464	1,666	947	715	379	27	5	22	102	485	1,033	1,674	8,519	9,511
2022	1,984	1,783	1,327	990	321	68	5	11	165	562	1,175	1,743	10,134	9,527
2023	1,716	1,549	1,617	947	155	9	41	21	101	616	1,019	1,191	8,982	9,514
2024	1,578	1,115	1,155	628	271	60	1	21	48	442	985	1,433	7,737	9,457

(Beginning in 1981)

<u>EXHIBIT N</u>

SAMPLE COPY
OF
COYOTE STATION
MONTHLY OPERATING REPORT
FOR
MONTH OF DECEMBER, 2024

Coyote Station Statement of Costs
December 24

FERC account	Account	Total	NWE 10%	MDU 25%	NMPA/MPC 30%	OTP 35%	Year-to-date
151	Coal inventory	(124,028.79)	(12,402.88)	(31,007.20)	(37,208.64)	(43,410.07)	283,749.93
151	Fuel oil inventory	(173,658.03)	(17,365.80)	(43,414.51)	(52,097.41)	(60,780.31)	(765,308.33)
154	Materials & supplies inventory	(3,692.64)	(369.26)	(923.16)	(1,107.79)	(1,292.43)	678,115.54
154	Lime inventory	(2,079.65)	(207.97)	(519.91)	(623.90)	(727.87)	10,826.92
154	Carbon inventory	(26,732.81)	(2,673.28)	(6,683.20)	(8,019.84)	(9,356.49)	41,349.93
154	TIFI (Targeting In-Furnace Injection) inventory	82,324.62	8,232.46	20,581.16	24,697.39	28,813.61	161,193.10
143	Receivable Insurance	-	-	-	-	-	-
165	Prepaid insurance	-	-	-	-	-	1,428,572.00
408.1	Coal conversion tax	25,836.03	2,574.93	6,467.95	7,756.18	9,036.97	301,005.36
411.8	Gains from disposition of allowances	-	-	-	-	-	(9.36)
426.1	Donations and other deductions	1,170.00	117.00	292.50	351.00	409.50	12,360.00
431	Interest from DWC Arbitration	-	-	-	-	-	-
454	Rent from electric property	-	-	-	-	-	(11,135.25)
456	CDWW revenues	(13,481.53)	(1,348.15)	(3,370.38)	(4,044.46)	(4,718.54)	(58,455.24)
456	Other electric revenues	(19,087.74)	(1,908.77)	(4,771.94)	(5,726.32)	(6,680.71)	(196,990.28)
500	General office payroll	-	-	-	-	-	-
500	Operation supervision & engineering	158,993.58	15,899.36	39,748.40	47,698.07	55,647.75	2,374,263.04
501.1	Fuel burned	5,547,884.90	554,788.49	1,386,971.23	1,664,365.47	1,941,759.71	64,961,661.95
501.1	Fuel reconciliation	-	(16,027.00)	16,512.00	9,937.00	(10,422.00)	-
501	Other fuel expenses	13,420.63	1,342.06	3,355.16	4,026.19	4,697.22	148,746.31
502	Lime consumed	257,297.74	25,729.77	64,324.44	77,189.32	90,054.21	2,168,235.42
502	Carbon consumed	119,360.09	11,936.01	29,840.02	35,808.03	41,776.03	1,123,221.36
502	TIFI (Targeting In-Furnace Injection) Consumed	290,720.98	29,072.10	72,680.25	87,216.29	101,752.34	1,551,884.67
502	Lime reconciliation	-	(754.00)	777.00	468.00	(491.00)	-
502	Carbon reconciliation	-	(350.00)	361.00	217.00	(228.00)	-
502	TIFI (Targeting In-Furnace Injection) reconciliation	-	(852.00)	878.00	529.00	(555.00)	-
502	Other steam expenses	346,772.65	34,677.27	86,693.16	104,031.80	121,370.42	4,404,236.65
505	Electric expenses	170,046.80	17,004.68	42,511.70	51,014.04	59,516.38	2,189,770.19
506	Miscellaneous steam power expenses	717,073.14	71,707.31	179,268.29	215,121.94	250,975.60	2,965,862.75
507	Rents, steam power generation	456.13	45.61	114.03	136.84	159.65	63,681.13
510	Maintenance supervision & engineering	48,515.33	4,851.53	12,128.83	14,554.60	16,980.37	647,531.12
511	Maintenance of structures	155,518.57	15,551.86	38,879.64	46,655.57	54,431.50	1,107,897.71
512	Maintenance of boiler plant	393,769.64	39,376.96	98,442.41	118,130.89	137,819.38	6,180,958.62
513	Maintenance of electric plant	22,259.09	2,225.91	5,564.77	6,677.73	7,790.68	453,442.08
514	Maintenance of misc. steam plant	210,573.70	21,057.37	52,643.43	63,172.11	73,700.79	2,113,415.07
556	System control & load dispatching	37,821.29	3,782.13	9,455.32	11,346.39	13,237.45	453,855.48
567	Rents, transmission expenses	-	-	-	-	-	123,257.49
	Total	$ 8,237,053.72	$ 805,713.70	$ 2,077,800.39	$ 2,482,272.49	$ 2,871,267.14	$ 94,917,195.36

Coyote Station Inventories
December 24

Coal	Total Tons	Total Dollars	Total Cost/ton	NWE 10% Tons	NWE 10% Dollars	MDU 25% Tons	MDU 25% Dollars	NMPA/MPC 30% Tons	NMPA/MPC 30% Dollars	OTP 35% Tons	OTP 35% Dollars	Year-to-date Tons	Year-to-date Dollars	Year-to-date Cost/ton
Beginning inventory	46,487	$ 1,822,361.40	$ 39.202	4,649	$ 182,236.16	11,625	$ 455,590.33	13,946	$ 546,708.47	16,267	$ 637,826.44	48,438	$ 1,414,582.68	$ 29.204
Purchases	197,784	5,328,429.35	26.941	19,778	532,842.94	49,446	1,332,107.34	59,335	1,598,528.81	69,225	1,864,950.26	1,931,767	$ 63,972,807.56	$ 33.116
Available	244,271	7,150,790.75	29.274	24,427	715,079.10	61,071	1,787,697.67	73,281	2,145,237.28	85,492	2,502,776.70	1,980,205	$ 65,387,390.24	$ 33.021
Burned for generation	186,256	5,452,458.14	29.274	18,626	545,245.81	46,564	1,363,114.54	55,877	1,635,737.44	65,189	1,908,360.35	1,922,190	$ 63,689,057.63	$ 33.134
Ending inventory	58,015	$ 1,698,332.61	$ 29.274	5,801	$ 169,833.29	14,507	$ 424,583.13	17,404	$ 509,499.84	20,303	$ 594,416.35	58,015	$ 1,698,332.61	$ 29.274
Fuel reconciliation				(547)	$ (16,027.00)	564	$ 16,512.00	339	$ 9,937.00	(356)	$ (10,422.00)			

Fuel oil	Total Gallons	Total Dollars	Total Cost/gallon	NWE 10% Gallons	NWE 10% Dollars	MDU 25% Gallons	MDU 25% Dollars	NMPA/MPC 30% Gallons	NMPA/MPC 30% Dollars	OTP 35% Gallons	OTP 35% Dollars	Year-to-date Gallons	Year-to-date Dollars	Year-to-date Cost/gallon
Beginning inventory	466,245	$ 1,349,182.29	$ 2.894	46,609	$ 134,918.15	116,543	$ 337,295.49	139,864	$ 404,754.63	163,229	$ 472,214.02	617,311	$ 1,940,832.59	$ 3.14
Purchases	-	(84.59)	-	-	(8.46)	-	(21.15)	-	(25.38)	-	(29.60)	248,191	$ 623,415.90	$ 2.51
Available	466,245	$ 1,349,097.70	2.894	46,609	134,909.69	116,543	337,274.34	139,864	404,729.25	163,229	472,184.42	865,502	$ 2,564,248.49	$ 2.96
Burned for generation	32,974	$ 95,426.76	2.894	3,297	9,542.68	8,244	23,856.69	9,892	28,628.03	11,541	33,399.36	420,153	$ 1,272,604.32	$ 3.03
Burned for heat	27,003	$ 78,146.68	2.894	2,700	7,814.67	6,751	19,536.67	8,101	23,444.00	9,451	27,351.34	39,081	$ 116,119.91	$ 2.97
Ending inventory	406,268	$ 1,175,524.26	$ 2.893	40,612	$ 117,552.34	101,548	$ 293,880.98	121,871	$ 352,657.22	142,237	$ 411,433.72	406,268	$ 1,175,524.26	$ 2.89

Lime	Total Tons	Total Dollars	Total Cost/ton	NWE 10% Tons	NWE 10% Dollars	MDU 25% Tons	MDU 25% Dollars	NMPA/MPC 30% Tons	NMPA/MPC 30% Dollars	OTP 35% Tons	OTP 35% Dollars	Year-to-date Tons	Year-to-date Dollars	Year-to-date Cost/ton
Beginning inventory	1,490	$ 223,930.27	$ 150.289	142	$ 22,393.10	371	$ 55,982.60	443	$ 67,179.14	534	$ 78,375.43	1,446	$ 211,023.70	$ 145.94
Purchases	1,700	255,218.09	150.128	170	25,521.81	425	63,804.52	510	76,565.43	595	89,326.33	14,546	$ 2,179,062.34	$ 149.80
Available	3,190	479,148.36	150.203	312	47,914.91	796	119,787.12	953	143,744.57	1,129	167,701.76	15,992	$ 2,390,086.04	$ 149.46
Consumed	1,713	257,297.74	150.203	171	25,729.77	428	64,324.44	514	77,189.32	600	90,054.21	14,515	$ 2,168,235.42	$ 149.38
Ending inventory	1,477	$ 221,850.62	$ 150.204	141	$ 22,185.14	368	$ 55,462.68	439	$ 66,555.25	529	$ 77,647.55	1,477	$ 221,850.62	$ 150.20
Reagent reconciliation in tons				(5)	$ (754.00)	5	$ 777.00	3	$ 468.00	(3)	$ (491.00)			

Activated Carbon	Total Pounds	Total Dollars	Total Cost/pound	NWE 10% Pounds	NWE 10% Dollars	MDU 25% Pounds	MDU 25% Dollars	NMPA/MPC 30% Pounds	NMPA/MPC 30% Dollars	OTP 35% Pounds	OTP 35% Dollars	Year-to-date Pounds	Year-to-date Dollars	Year-to-date Cost/pound
Beginning inventory	120,185	$ 128,644.84	$ 1.070	12,018	$ 12,864.52	30,041	$ 32,161.17	36,052	$ 38,593.44	42,074	$ 45,025.71	122,101	$ 60,562.10	$ 0.50
Purchases	83,560	92,627.28	$ 1.109	8,356	9,262.73	20,890	23,156.82	25,068	27,788.18	29,246	32,419.55	1,276,360	$ 1,164,571.29	$ 0.91
Available	203,745	221,272.12	1.086	20,374	22,127.25	50,931	55,317.99	61,120	66,381.62	71,320	77,445.26	1,398,461	$ 1,225,133.39	$ 0.88
Consumed	109,908	119,360.09	1.086	10,991	11,936.01	27,477	29,840.02	32,972	35,808.03	38,468	41,776.03	1,304,624	$ 1,123,221.36	$ 0.86
Ending inventory	93,837	101,912.03	$ 1.086	9,383.00	10,191.24	23,454.00	25,477.97	28,148.00	30,573.59	32,852.00	35,669.23	93,837	$ 101,912.03	$ 1.09
Reagent reconciliation in tons				(0)	$ (350.00)	0	$ 361.00	0	$ 217.00	(0)	$ (228.00)			

TIFI (Targeting In-Furnace Injection)	Total Pounds	Total Dollars	Total Cost/pound	NWE 10% Pounds	NWE 10% Dollars	MDU 25% Pounds	MDU 25% Dollars	NMPA/MPC 30% Pounds	NMPA/MPC 30% Dollars	OTP 35% Pounds	OTP 35% Dollars	Year-to-date Pounds	Year-to-date Dollars	Year-to-date Cost/pound
Beginning inventory	115,829	$ 78,868.48	$ 0.681	11,582	$ 7,886.85	28,957	$ 19,717.10	34,749	$ 23,660.54	40,541	$ 27,603.99	-	$ -	$ -
Purchases	537,960	373,045.60	$ 0.693	53,796	37,304.56	134,490	93,261.40	161,388	111,913.68	188,286	130,565.96	2,627,960	$ 1,713,077.77	$ 0.65
Available	653,789	451,914.08	0.691	65,378	45,191.41	163,447	112,978.50	196,137	135,574.22	228,827	158,169.95	2,627,960	$ 1,713,077.77	$ 0.65
Consumed	420,725	290,720.98	0.691	42,073	29,072.10	105,181	72,680.25	126,218	87,216.29	147,253	101,752.34	2,394,896	$ 1,551,884.67	$ 0.65
Ending inventory	233,064	161,193.10	$ 0.692	23,305.00	16,119.31	58,266.00	40,298.25	69,919.00	48,357.93	81,574.00	56,417.61	233,064	$ 161,193.10	$ 0.69
Reagent reconciliation in tons				(1)	($852)	1	$878	0	$529	(0)	($555)			

Coyote Station
Net and Gross Generation (kWh)
December 24

	35% OTP	30% NMPA/MPC	25% MDU	10% NWE	100% Total	Year-to-date
Net scheduled generation	74,581,678	64,725,031	54,295,926	20,733,035	214,335,670	2,208,336,820
Net generation	74,555,358	64,725,031	54,295,926	20,733,035	214,309,350	2,208,115,780
Station power:						
Ownership % X minimum net load	3,900,745	3,343,496	2,786,247	1,114,499	11,144,987	128,165,657
Net scheduled generation % X plant shutdown at ownership %	1,385,739	1,191,270	986,151	381,443	3,944,603	31,181,903
Total station power	5,286,484	4,534,766	3,772,398	1,495,942	15,089,590	159,347,560
Gross generation	79,841,842	69,259,797	58,068,324	22,228,977	229,398,940	2,367,463,340
Station power due to	26,320				26,320	221,040

N-4

Coyote Station
Apportionment of Other Than Minimum Net Load Fuel & Reagent Costs
December 24

A. Minimum net load (MNL) fuel costs

BTUs to maintain minimum net load (constant)		1,750,000,000
divided by average monthly BTU per pound of fuel	from fuel report	6,951
equals pounds of coal required for minimum net load per hour		251762.3364
divided by 2000 pounds per ton of fuel		125.88
times average cost per ton of coal burned		29.27
equals minimum net load coal cost per hour		3,685.05
times total monthly hours of plant operation	from fuel report	659.47
Minimum net load fuel costs		2,430,176.84

B. Ratio of tons required for minimum net load to actual tons burned

Coal tons required for minimum net load	125.88
times monthly hours of plant operation	659.47
equals tons required for minimum net load	83,014.85
divided by actual tons burned	186,256.00
Ratio of minimum net load tons to actual tons burned	0.4457

C. Other minimum net load costs

Account 501 costs other than fuel burned	13,420.63
times ratio of minimum net load tons to actual tons burned	0.4457
Minimum net load ash disposal costs	5,981.61

D. Costs to be assessed against generation above minimum net load

Total account 501 charges	5,561,305.53
less minimum net load fuel costs	(2,430,176.84)
less minimum net load ash disposal costs	(5,981.61)
less fuel oil costs	(95,426.76)
Total costs for generation above minimum net load	$3,029,720.32

E. Generation above minimum net load

	NWE	MDU	NMPA/MPC	OTP
Actual generation net of regulation	20,733,035	54,295,926	64,725,031	74,555,358
ownership percentage	10.000%	25.000%	30.000%	35.000%
minimum generation (125 MW * hours)	8,243,375	20,608,438	24,730,125	28,851,813
Generation above minimum net load	12,489,660	33,687,489	39,994,906	45,703,546
Percent of generation above MNL	9.471%	25.545%	30.328%	34.656%

F. Distribution of Lignite costs above minimum net load

	NWE	MDU	NMPA/MPC	OTP
Percent of generation above MNL	0.09471	0.25545	0.30328	0.34656
less ownership percentage	0.10000	0.25000	0.30000	0.35000
equals percent above/below ownership	(0.00529)	0.00545	0.00328	(0.00344)
times cost for generation above MNL	3,029,720.32	3,029,720.32	3,029,720.32	3,029,720.32
Adjustment of fuel costs	($16,027)	$16,512	$9,937	($10,422)
Adjustment of tons (÷ ending inv. $/ton) $29.2740	(547)	564	339	(356)

Coyote Station
Apportionment of Other Than Minimum Net Load Fuel & Reagent Costs
December 24

G. Distribution of Lime costs above minimum net load

Tons of lime consumed	1,713
divided by tons of coal burned	186,256
equals percent of lime to coal	0.9197%
times minimum net load tons	83,014.85
equals minimum net load lime tons	763.49
times average cost/ton of lime burned	150.20
Minimum net load lime costs	114,678.37
Total lime costs	257,297.74
less minimum net load lime costs	(114,678.37)
Lime costs above MNL	$142,619.37

	NWE	MDU	NMPA/MPC	OTP
Percent of generation above MNL	0.09471	0.25545	0.30328	0.34656
less ownership percentage	0.10000	0.25000	0.30000	0.35000
equals percent above/below ownership	(0.00529)	0.00545	0.00328	(0.00344)
times reagent costs above MNL	142,619.37	142,619.37	142,619.37	142,619.37
Adjustment of reagent costs	($754)	$777	$468	($491)
Adjustment of reagent tons	(5)	5	3	(3)

H. Distribution of Carbon costs above minimum net load

Tons of activated carbon consumed	55
divided by tons of coal burned	186,256
equals percent of activated carbon to coal	0.0295%
times minimum net load tons	83,014.85
equals minimum net load activated carbon tons	24.49
times average cost/ton of activated carbon burned	2,172.00
Minimum net load activated carbon costs	53,199.15
Total activated carbon costs	119,360.09
less minimum net load activated carbon costs	(53,199.15)
Activated carbon costs above MNL	$66,160.94

	NWE	MDU	NMPA/MPC	OTP
Percent of generation above MNL	0.09471	0.25545	0.30328	0.34656
less ownership percentage	0.10000	0.25000	0.30000	0.35000
equals percent above/below ownership	(0.00529)	0.00545	0.00328	(0.00344)
times reagent costs above MNL	66,160.94	66,160.94	66,160.94	66,160.94
Adjustment of reagent costs	($350)	$361	$217	($228)
Adjustment of reagent tons	(0)	0	0	(0)

I. Distribution of TIFI (Targeted In-Furnace Injection) costs above minimum net load

Tons of TIFI consumed	210
divided by tons of coal burned	186,256
equals percent of TIFI to coal	0.1129%
times minimum net load tons	83,014.85
equals minimum net load TIFI tons	93.76
times average cost/ton of TIFI burned	1,382.00
Minimum net load TIFI costs	129,575.20
Total TIFI costs	290,720.98
less minimum net load TIFI Costs	(129,575.20)
TIFI costs above MNL	$161,145.78

	NWE	MDU	NMPA/MPC	OTP
Percent of generation above MNL	0.09471	0.25545	0.30328	0.34656
less ownership percentage	0.10000	0.25000	0.30000	0.35000
equals percent above/below ownership	(0.00529)	0.00545	0.00328	(0.00344)
times reagent costs above MNL	161,145.78	161,145.78	161,145.78	161,145.78
Adjustment of reagent costs	($852)	$878	$529	($555)
Adjustment of reagent tons	(1)	1	0	(0)

Coyote Station Prepaid Insurance
December 24

Excess Liability

Insurer	AEGIS/EIM
Policy #	XL5064812P
Policy term	January 1, 2024 to January 1, 2025
Premium	$264,136.50 on January 2024 SOC

General Liability

Insurer	Starr Indemnity & Liability Company
Policy #	1000090695231
Policy term	January 1, 2024 to January 1, 2025
Premium	$61,742.00 on January 2024 SOC

Auto Liability

Insurer	Everest
Policy #	EN4CA00126-231
Policy term	January 1, 2024 January 1, 2025
Premium quarterly	$6,381.00 on January 2024 SOC

Fiduciary Liability

Insurer	Hudson Insurance Company
Policy #	SFD31212099-01
Policy term	November 1, 2024 to November 1, 2025
Premium	$3,120.09 on November 2024 SOC

Fiduciary Excess Liability

Insurer	Endurance American Insurance Company
Policy #	FLX30012523402
Policy term	November 1, 2024 to November 1, 2025
Premium	$1,944.32 on November 2024 SOC

Crime Primary

Insurer	Great American Insurance Company
Policy #	SAA 51777-81-18-00
Policy term	November 1, 2024 to November 1, 2025
Premium	$1,659.025 on November 2024 SOC

Property Insurance

Insurer	FM Global
Policy #	1096734
Policy term	April 1, 2024 to April 1, 2025
Premium	1,039,018.93 on April 2024 SOC

Cyber Liability

Insurer	Travelers
Policy #	CP5733506P
Policy term	January 1, 2024 January 1, 2025
Premium	$16,510.97 on January 2024 SOC

Terrorism Insurance

Insurer	QBE UK Limited
Policy #	10910L22
Policy term	April 15, 2024 to April 15, 2025
Premium	$34,059.16 on May 2024 SOC

Coyote Station
Additional Information
December 24

Advance liability balance:	NWE	MDU	NMPA/MPC
Advance liability prior month	76,410.37	(160,602.63)	(497,992.20)
Plus current calendar month cash advances	906,203.00	2,316,350.00	2,778,933.00
Minus current month O&M, etc. costs	(805,713.70)	(2,077,800.39)	(2,482,272.49)
Minus current month CWIP costs	(67,496.37)	(168,740.95)	(202,489.13)
	109,403.30	(90,793.97)	(403,820.82)

BTUs per pound of lignite	6,951
Materials and supplies balance	$9,656,939.49
Total hours plant operated during the month	659.47

Coyote Station
Coal Conversion Tax Calculation
December 24

	9.7% NWE	25.3% MDU	30.2% NMPA/MPC	34.8% OTP	100.0% Total
Fixed tax (capacity)					
Installed capacity	41,459	103,647	124,376	145,106	414,588
Multiplier (60%)	0.60	0.60	0.60	0.60	0.60
Capacity subject to tax	24,875	62,188	74,626	87,064	248,753
Hours in month	744	744	744	744	744
KWh subject to tax	18,507,000	46,267,872	55,521,744	64,775,616	185,072,232
Tax rate (.65 mills)	0.00065	0.00065	0.00065	0.00065	0.00065
Fixed tax	12,030.00	30,074.00	36,089.00	42,103.95	120,296.95
Reduced county and lignite tax rat	19.25%	19.25%	19.25%	19.25%	19.25%
Fixed tax due	2,315.78	5,789.25	6,947.13	8,105.01	23,157.16
Variable tax (generation)					
Gross generation (kWh)	22,228,977	58,068,324	69,259,797	79,841,842	229,398,940
Station power	1,495,942	3,772,398	4,534,766	5,286,484	15,089,590
Net generation	20,733,035	54,295,926	64,725,031	74,555,358	214,309,350
Tax rate (.25 mills)	0.00025	0.00025	0.00025	0.00025	0.00025
Variable Tax	5,183.00	13,574.00	16,181.00	18,639.34	53,577.34
Lignite research tax	5.00%	5.00%	5.00%	5.00%	5.00%
Variable Tax Due	259.15	678.70	809.05	931.97	2,678.87
Total coal conversion tax	$ 2,574.93	$ 6,467.95	$ 7,756.18	$ 9,036.98	$ 25,836.03
Adjustment of coal conversion tax	$ (9.00)	$ 9.00	$ 5.00	$ (5.00)	$ -

Coyote Station Construction Work in Progress
December 24

Project	Description	Acct.	Total	NWE 10%	MDU 25%	NMPA/MPC 30%	OTP 35%	Total-to-date	In service
107870	Yard pond pump replacements	312	-	-	-	-	-	386,963.61	07/15/24
108081	Exciter Capital Spare	314	39,750.00	3,975.00	9,937.50	11,925.00	13,912.50	432,234.31	12/20/24
108101	Replace one plant vehicle	316	-	-	-	-	-	55,679.70	01/10/24
108120	BFP lube oil pump & motor replaceme	312	-	-	-	-	-	93,169.08	
108210	Miscellaneous Tools and Equipment -	316	2,578.65	257.87	644.66	773.60	902.52	19,561.88	12/20/24
108212	Replace PCs & Office Equipment-2024	316	-	-	-	-	-	2,717.55	12/20/24
108213	Contingencies - 2024	--	188,105.54	18,810.55	47,026.39	56,431.66	65,836.94	815,661.83	12/20/24
108215	HVAC replacement 2024	311	(6,196.00)	(619.60)	(1,549.00)	(1,858.80)	(2,168.60)	32,769.69	10/30/24
108217	Condensate pump replacements (3)	314	74.50	7.45	18.63	22.35	26.07	350,211.25	
108218	Baghouse bag replacement-2024	312	-	-	-	-	-	570,291.71	
108219	Glycol heater bundle replacement	312	5,153.74	515.37	1,288.44	1,546.12	1,803.81	109,674.06	
108220	Fire line in boiler building UG	311	15,372.23	1,537.22	3,843.06	4,611.67	5,380.28	184,564.67	11/27/24
108221	Bleach tank replacement	312	1,371.61	137.16	342.90	411.48	480.07	98,260.38	07/01/24
108222	Rotary Seal Replacement 2024	312	8,503.49	850.35	2,125.87	2,551.05	2,976.22	133,427.45	12/20/24
108321	Air Heater Hot and Interm Basket	312	420,250.00	42,025.00	105,062.50	126,075.00	147,087.50	1,827,341.22	
	Total CWIP costs		674,963.76	67,496.37	168,740.95	202,489.13	236,237.31	5,112,528.39	