APPENDIX A: MINNESOTA POWER'S 2024 ANNUAL ELECTRIC

Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service areas submit to the Minnesota Department of Commerce an annual report containing historical and forecast customer sales and demand values, including forecast methodology and discussion. This report is due by July 1 of each year. Minnesota Power's 2024 Annual Electric Utility Forecast Report ("AFR 2024") filed in Docket No. E-999/PR-24-11, contains all the forms and information necessary to meet this annual requirement.[1]

Minnesota Power's AFR 2024 contains historical sales and demand data, as well as the customer energy sales and demand forecasts that serve as the expected load forecast and the starting point for the 2025-2039 Integrated Resource Plan ("2025 IRP"). AFR 2024 also includes a load growth planning scenario that takes into consideration potential load growth from regional electrification expansion efforts, hyperscaler industrial customers (e.g., data centers), and/or green steel initiatives. Minnesota Power works with communities through outreach to find out more about their distributed generation goals. Trends in distributed solar and known projects that have a material impact are captured in the customer outlook used in the IRP analysis.

The 2025 IRP also includes three customer load forecast scenarios that were not filed as part of AFR 2024. These scenarios are defined as "+1100 MW," "+1500 MW," and "-200 MW." The "+1100 MW" growth scenario is the basis for the 2025 Growth Plan and the other two scenarios are used as sensitivities in the IRP analysis process. These scenarios are identical to the AFR 2024 "Expected" scenario with the following modifications:

1) The "+1100 MW" scenario includes approximately 1100 MW of load growth within the industrial class that comes online between 2028 and 2035. This scenario forms the base for the Company's "2025 Growth Plan," discussed in Section V.
2) The "+1500 MW" scenario includes an additional 1500 MW of industrial load growth that comes online between 2027 and 2032 plus 150 percent load growth amongst the residential and commercial classes.
3) The "-200 MW" scenario includes a 200 MW decline in industrial demand starting in 2028.

The growth scenarios are based on existing customer expectations of increasing energy demand. These three scenarios do not include all potential opportunities for load growth or for load loss.

As shown in Figure 1 and Figure 2, the three sensitivity scenarios outline a wide range of study for Minnesota Power's IRP analysis. They are included as -200, +1100 Growth Scenario, and +1500. All three scenarios shift Minnesota Power's energy sales and system peak significantly throughout the forecast, emphasizing how a large increase or decrease in load could change Minnesota Power's load profile. The "+1100 MW Growth Scenario," along with the Base Case are the two primary outlooks used to develop the 2025 Plan as they represent the latest in customer expectations.

[1] *In the Matter Annual Electric Utility Reports*, Docket No. E-999/PR-24-11, Minnesota Power's 2024 Annual Electric Utility Forecast Report (Aug. 1, 2024).

Figure 1. Demand Outlook Sensitivities for MISO Coincident Peak ("CP")

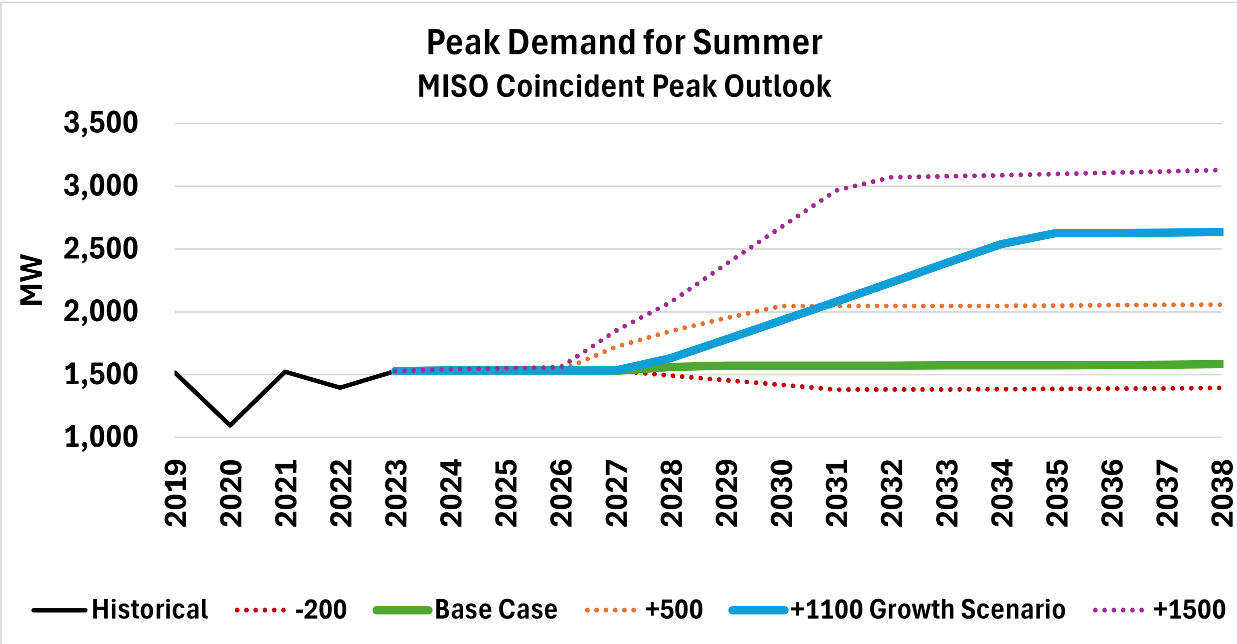
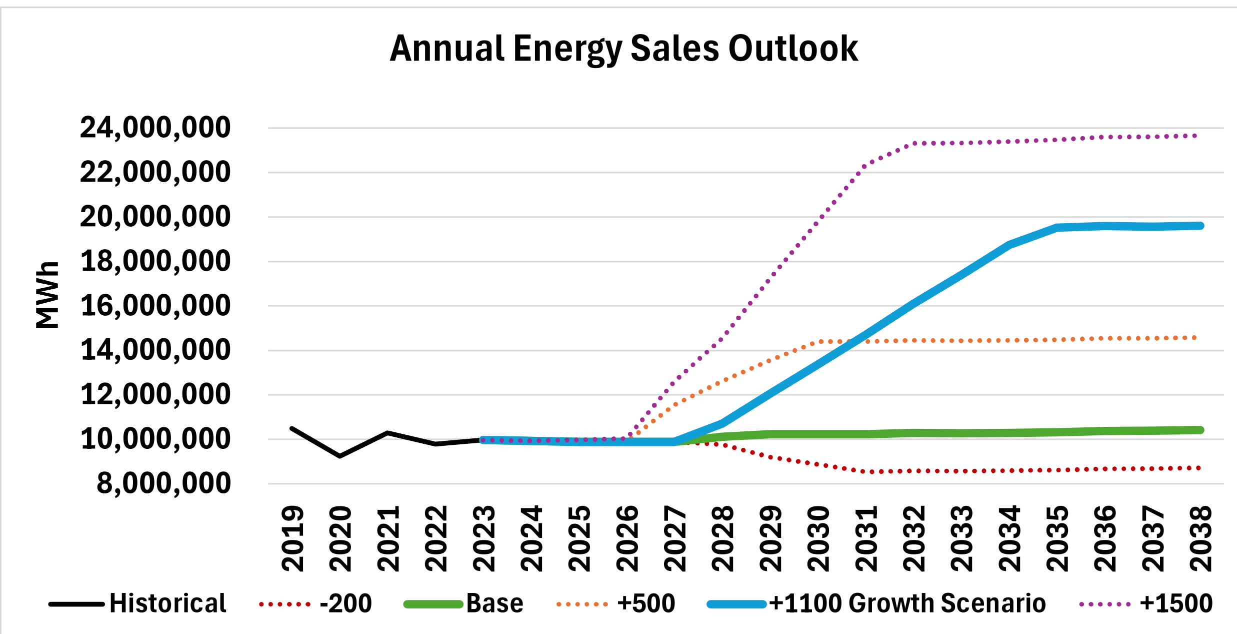


Figure 2. Energy Outlook Sensitivities



Depicted in Figure 3 and Figure 4 is the comparison of Minnesota Power's load profile between the Base Case and +1100 MW Growth Scenario. Significant load coming online, like that of the +1100 MW Growth Scenario, would redefine Minnesota Power's load profile. A change of this magnitude would greatly increase Minnesota Power's already large industrial customer class.

Figure 3. Minnesota Power Load Profile: Base Case

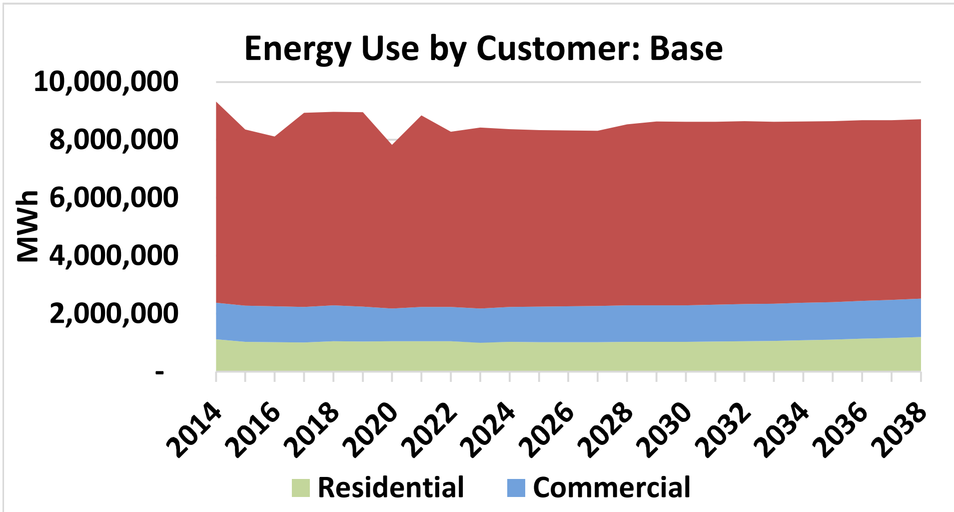
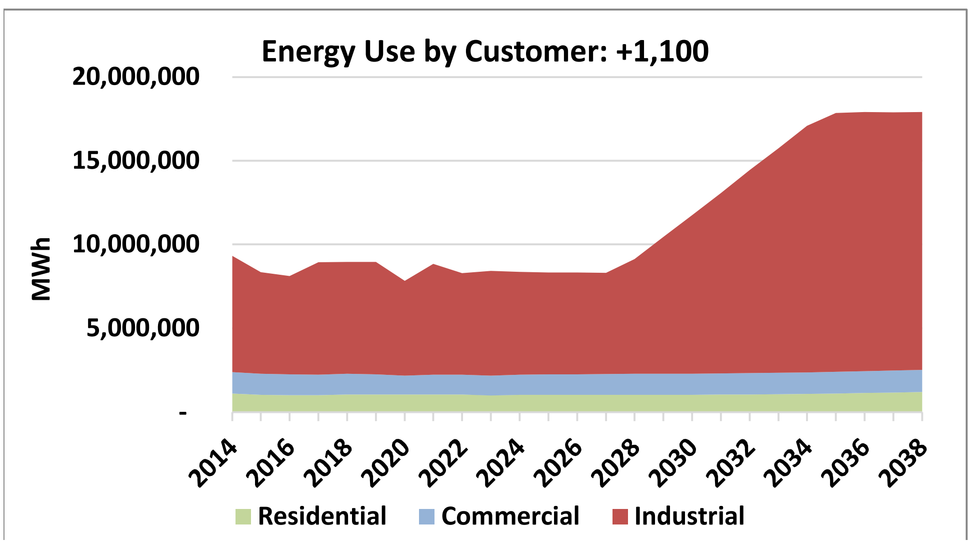


Figure 4. Minnesota Power Load Profile: +1100 MW Growth Scenario



minnesota power
AN ALLETE COMPANY

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August 1, 2024

VIA E-FILING
Ms. Anne Sell
Department of Commerce – Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN 55101-2198

Re: Minnesota Power's 2024 Annual Electric Utility Forecast Report
Docket No. E-999/PR-24-11

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2024 Annual Electric Utility Forecast Report pursuant to Minn. Stat. § 216C.17, subd. 2 and Minn. Rules Chapter 7610. As an electric utility with Minnesota service areas, Minnesota Power (or the "Company") is required to submit to the Minnesota Department of Commerce – Division of Energy Resources ("Department") by July 1 of each year an annual report specifying its short- and long-term energy demand forecasts and the facilities necessary to meet the demand.

Information included in the "**ELEC_68_2023 Largest Customer List.xlsx**" and "**ELEC_68_2023 Forecast Report.xlsx**" Excel workbooks, as well as the **Methodology** document has been designated as **TRADE SECRET**.

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Department and Minnesota Public Utilities Commission eDockets/eFiling system using Docket Number 24-11:

- ELEC_68_2023 Annual Report.xlsx
- ELEC_68_2023 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2023 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2023 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2023 MN Service Area Map.pdf
- ELEC_68_2023 USDOE EIA-861.pdf
- ELEC_68_2023 Rate Schedules.pdf
- METHOD23.pdf (**TRADE SECRET** & Public versions)

Please don't hesitate to contact me if you need additional paper copies or have any questions.

Sincerely,

Claire Vatalaro

Claire Vatalaro
Regulatory Compliance Specialist
Minnesota Power
218-355-3082
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CMRV:th
Attach.

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

In the Matter of Minnesota Power's 2024 Annual Electric Utility Forecast Report	Docket No. E-999/PR-24-11

INTRODUCTION

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption and seasonal peak demand requirements. Minnesota Power's forecast process combines a sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power (or the Company) is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2024 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, completion of systematic and replicable processes, and thorough analysis of results.

The 2024 AFR forecasts a total of 9.9M MWh of energy sales in 2024 increasing to 10.4M MWh of energy sales in 2038. The system peak forecast, by 2038, is 1,724 (winter), MP's actual system peak was 1,630 MW in 2023 with all mining and metals customers operating

Additionally, as national and regional trends continue to identify a new landscape for energy growth, the company also included in this year's submittal a new load growth Forecast Planning Scenario (Section VI) that takes into consideration potential growth from regional electrification efforts, data centers, and/or green steel opportunities. These are important components to monitor for the utility as it continues to prepare for the electric needs of its service area.

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Table of Figures

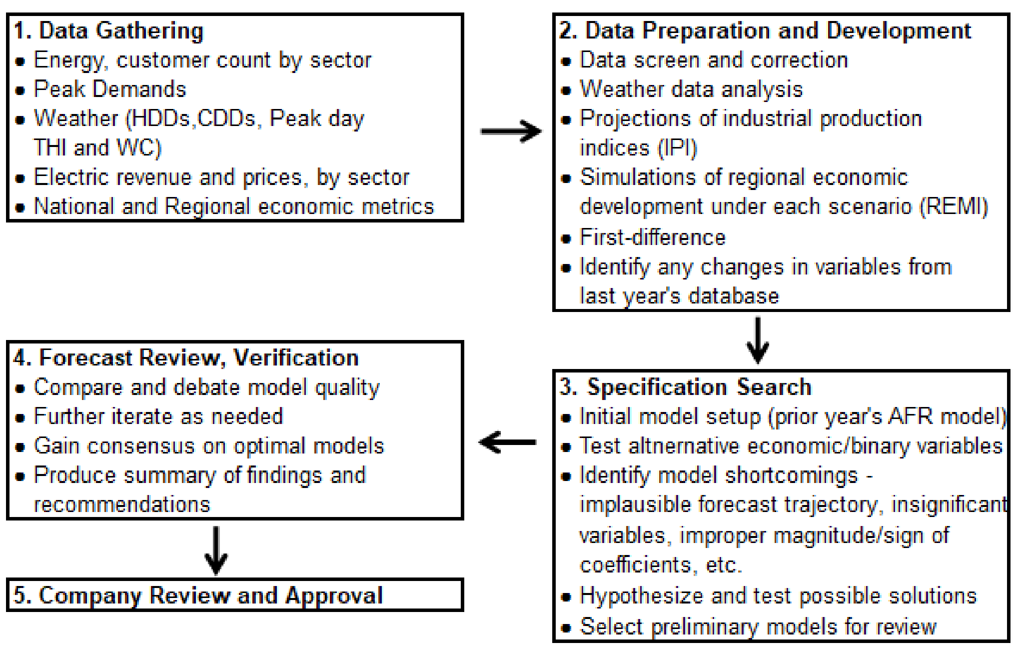
I. Forecast Methodology

A. Overall Framework (7610.0320, Subp. 1.A)

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50 percent probability that a realized actual will be less than forecast and a 50 percent probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) initial review and verification, and 5) internal company review and approval. The steps of the forecast process are sequential, and the process is diagrammed in Figure 1 below.

Figure 1: Minnesota Power's Forecast Process



B. Specific Analytical Techniques (7610.0320, Subp. 1.B) and Relation to Forecast (7610.0320, Subp. 1.C)

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency of definition in a variable series and identify different potential relationships between predictor variables and the dependent variable. Minnesota Power uses the following data transformations in data development:

- *Constant-dollar Deflating/Inflating* – is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2012 as its base year in AFR 2024. The 2012 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis (BEA).
- *Per-day Conversion* – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.
- *De-trend and De-seasonalize* – is the process of removing the historical trend/seasonality from a data series. This reduces the potential for the spurious, or *false,* correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable (peak demand).
- *First Difference* – changes the definition of the series from *level* (e.g., the number of customers in a month) to *change* (e.g., the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no potential to mistake similarity of *trend* with similarity of *variation*.
- *Exponential* – is the application of an exponent to the series; either squaring or cubing the series. This transformation of raw data was only applied to the temperature variables in the Peak Demand model so the non-linear relationship of load to temperature could be more accurately quantified.

Interpolation Technique – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly frequency (e.g., U.S. Gross Domestic Product (GDP) is only available in quarterly and annual frequencies).

Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

Modeling Techniques – Most of the dependent count and energy variables are modeled using a trend variable to explain general, underlying growth and one or two economic/demographic variables to explain any economically-driven divergence from this trend. This approach to regression modeling reduces the potential for an independent variable to be erroneously identified as significant due to spurious, or *false,* correlation.

- *Leveraging Binary Variables to Account for Recent Trends* – Several of Minnesota Power's largest industrial and resale customers are in a time of significant change, and an accurate load forecast depends on properly identifying and accounting for these changes. Minnesota Power adjusts historical sales series to "back-out" recent large customer load additions to avoid double-counting customer usage in the forecast timeframe; once (partially) embedded in the econometric projection, and again through a post-regression load adjustment. This approach is appropriate when the load addition/loss is quantifiable (e.g., a new customer, or a new customer-owned generator).

  This approach is supplemented with the use of binary and trend variables that account for large changes in load that cannot be precisely quantified (such as a customer expansion that is not metered separately). The variables denote and account for a structural shift in a dependent variable (historical sales) and are then terminated at the start of the forecast timeframe to effectively "back out" this recent change so it can be accurately quantified and explicitly applied through a post-regression adjustment to the econometric series.
- *Polynomial temperature specification for peak demand* – The AFR 2024 peak demand model uses a third-degree (cubed) temperature series alongside an un-adjusted temperature series to capture the non-linear relationship of load to temperature. The two variables (cubed and un-adjusted) create a polynomial temperature specification.
- *Modeled Peak Demand using hour-specific weather observations* – Minnesota Power has modeled peak demand as a function of the weather observations specific to the hour in which the peak occurred. The Company identified the historical peak date/times and

queried an hourly weather observation dataset to identify the hourly temperature, humidity, and wind-chill coincident with the system peak. In theory, the temperature at the time of the peak should be more closely related with the load than a daily high or low temperature. As a rule, all models are ordinary least squares (OLS), which are simple, transparent, explainable, and produce optimal estimates of the coefficients. Once input variables' coefficients are determined to be statistically significant and models are finalized, they form the basis of the "econometrically determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/losses and/or adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

C. Statistical Techniques, Typical Computations Specifying Variables and Data, and the Results of Appropriate Statistical Tests (7610.0320, Subp. 1.D)

This section presents the statistical detail of all models utilized in the development of the AFR 2024 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, P-value and Heteroscedasticity and Autocorrelation Consistent (HAC) P-value. Minnesota Power includes the HAC P-value as it adjusts for biases resulting from autocorrelation and/or heteroscedasticity. These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment. Below, for each model, a graph displays the historical series, growth rates for timeframes of interest, and a comparison of this year's forecast to last year's forecast. There is a table that shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates, and key diagnostic statistics for the OLS model are shown in a table in the bottom left corner of each page. Minnesota Power also offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues. In addition, this portion of the documentation compares this year's model with last year's model and discusses findings or insights gained.

Figure 2: Residential Customer Count – Expected Scenario

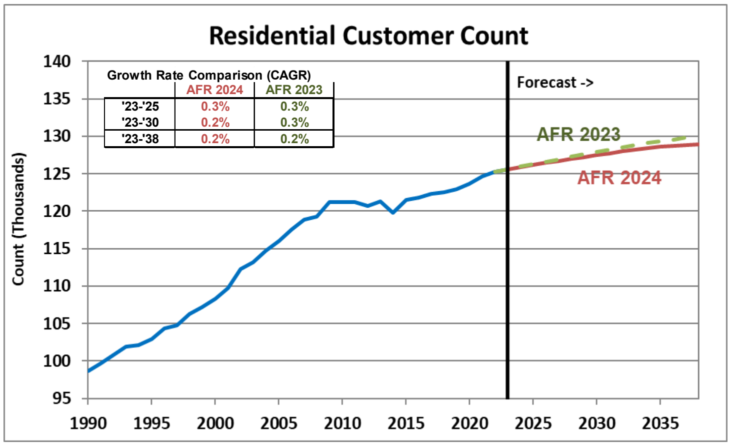
Residential Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	98,163.08	0.00%	0.00%
Bill_Res_1	(2,152.34)	0.00%	0.00%
Bill_Res_2	(2,790.01)	0.00%	0.00%
Dum_2009_2038	8,170.19	0.00%	0.00%
T_2009_2038	(33.15)	0.00%	0.00%
Res_C_2021_2038	1,573.24	0.00%	0.00%
MSA_HousStart_Cumulative	1.07	0.00%	0.00%

Residential Customer Count		
	Count	**Y/Y Growth**
2011	121,251	
2012	120,697	-0.5%
2013	121,314	0.5%
2014	121,601	0.2%
2015	121,515	-0.1%
2016	121,836	0.3%
2017	122,295	0.4%
2018	122,557	0.2%
2019	122,926	0.3%
2020	123,617	0.6%
2021	124,691	0.9%
2022	125,243	0.4%
2023	125,573	**0.3%**
2024	125,904	**0.3%**
2025	126,208	**0.2%**
2026	126,469	**0.2%**
2027	126,721	**0.2%**
2028	126,972	**0.2%**
2029	127,228	**0.2%**
2030	127,483	**0.2%**
2031	127,734	**0.2%**
2032	127,980	**0.2%**
2033	128,207	**0.2%**
2034	128,403	**0.2%**
2035	128,575	**0.1%**
2036	128,718	**0.1%**
2037	128,837	**0.1%**
2038	128,942	**0.1%**

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	6076
Durban-Watson	0.7
MAPE	0.27
In-Sample RMSE	411



Model Discussion

Both AFR 2024 and AFR 2023 had growth rates of approximately 0.2%, but AFR 2024 starts from a slightly higher level, resulting in a slightly higher residential cutomer count.

The key economic variable driving the residential customer count projection was Duluth MSA Cumulative Housing Starts, which is a rolling accumulation of annual housing starts beginning in 1990. This transformation converts a rate variable into a level variable, which better describes the underlying long-term trend of customer growth.

A combination of binary and trend variables ("Dum_2009_2038"" and "T_2009_2038") denote post-recession shifts in the relationship of MSA housing starts and residential customer count; housing starts continued, but customer counts stalled. This may be due in part to a shift towards suburban construction, where home construction continued but just outside Minnesota Power service territory. Without these corrective binary and a trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

The "Res_C_2021_2038" binary variable begins in mid-2021 and denotes a realignment of the MSA housing starts metric and customer counts; the mid-pandemic increase in demand for housing appears to be driving residential development in Minnesota Power's service territory, leading to customer growth. Two binary variables (Bill_Res) account for divergence from long-term trends due to "seasonal billing" between 1994 and 2001. This accounting practice recorded customer counts from November to May as 2,000-6,000 lower than from June to October.

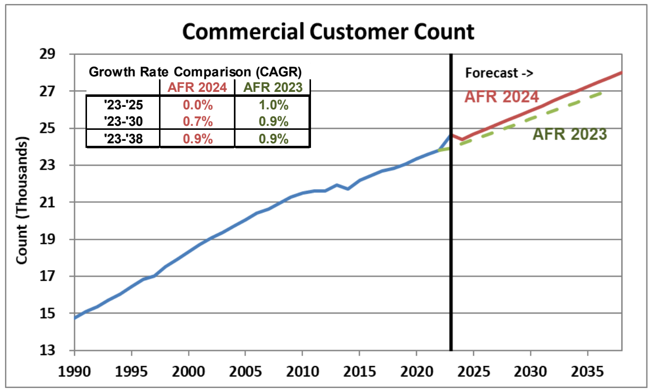
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model that's not over fit. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as the MAPE indicate model accuracy is comparable to AFR 2023 (0.27%).

Figure 3: Commercial Customer Count – Expected Scenario

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	13,174.12	0.00%	0.00%
T	26.57	0.00%	0.00%
Dum_2010_2038	1,476.72	0.00%	0.04%
T_2010_2038	(7.87)	0.00%	0.00%
MSA_Real_GMP	0.15	0.00%	0.00%



Commercial Customer Count		
	Count	Y/Y Growth
2011	21,603	
2012	21,614	0.1%
2013	21,915	1.4%
2014	22,096	0.8%
2015	22,170	0.3%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,059	1.0%
2020	23,346	1.2%
2021	23,580	1.0%
2022	23,816	1.0%
2023	24,650	**3.5%**
2024	24,405	**-1.0%**
2025	24,665	**1.1%**
2026	24,928	**1.1%**
2027	25,200	**1.1%**
2028	25,450	**1.0%**
2029	25,699	**1.0%**
2030	25,956	**1.0%**
2031	26,212	**1.0%**
2032	26,474	**1.0%**
2033	26,735	**1.0%**
2034	26,997	**1.0%**
2035	27,255	**1.0%**
2036	27,510	**0.9%**
2037	27,764	**0.9%**
2038	28,019	**0.9%**

Model Statistics	Magnitude
Adjusted R^2	99.7%
AIC	5293
Durban-Watson	0.5
MAPE	0.50
In-Sample RMSE	158

Model Discussion

The AFR 2024 Commercial Count forecast has a similar long-term annual growth rate to AFR 2023, both averaging approximately 0.9%.

The key economic driver of customer growth was Duluth MSA Real Gross Metro Product (GMP). Local GMP has historically tracked well with commercial customer counts, but COVID-19 caused the two series (GMP and commercial counts) to diverge, likely due to government supports like the Paycheck Protection Program (PPP) and Minnesota Power suspending disconnections for small business (general service) customers. A Trend variable accounts for some of this underlying customer count growth that appears unrelated to immediate economic conditions.

A combination of binary and trend variables ("Bi_2010_2038" and "T_2010_2038") denote a post-Great Recession, abrupt shift in customer count growth – customer counts grew at an average rate of 2.0% prior to 2010, and only 0.8% since. Without these corrective binary and trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

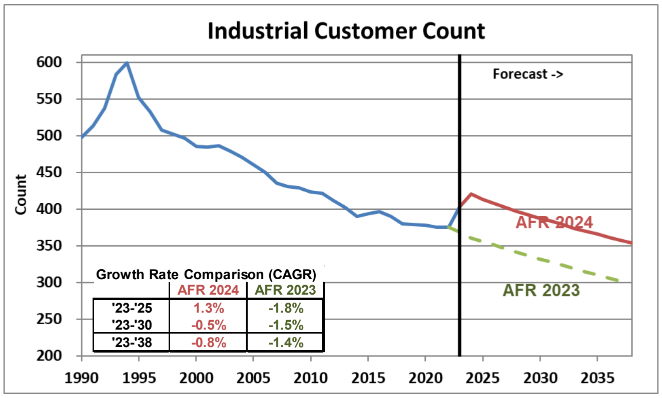
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are very similar: MAPE is the nearly the same as the 2023 model (0.37%), and RMSE is 158 vs. 107 in the 2023 model.

Figure 4: Industrial Customer Count – Expected Scenario

Industrial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	422.20	0.00%	0.00%
T	(0.35)	0.00%	0.00%
Ind_1991_1997	43.22	0.00%	0.00%
MFG_13	0.005	0.00%	0.00%
Ind_2023_2038	56.079	0.00%	0.00%



Industrial Customer Count		
	Count	Y/Y Growth
2011	421	
2012	411	-2.4%
2013	402	-2.2%
2014	394	-2.0%
2015	394	-0.1%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	378	-0.2%
2021	375	-0.7%
2022	375	0.0%
2023	403	7.4%
2024	421	4.4%
2025	413	-1.8%
2026	407	-1.4%
2027	402	-1.3%
2028	397	-1.3%
2029	392	-1.2%
2030	388	-1.1%
2031	383	-1.1%
2032	379	-1.2%
2033	374	-1.3%
2034	369	-1.2%
2035	365	-1.1%
2036	362	-1.1%
2037	358	-1.0%
2038	354	-1.0%

Model Statistics	Magnitude
Adjusted R^2	93.1%
AIC	3458
Durban-Watson	0.1
MAPE	2.21
In-Sample RMSE	17

Model Discussion

The AFR 2024 forecast annual growth rate for industrial customer count increased from -1.4% to -0.8%, with the customer count projection declining to 354 by 2038 compared to AFR 2023's customer count of 302 by 2037.

The key economic driver of industrial customer count was Manufacturing sector employment (13-County). This sector was a good representation of Minnesota Power's industrial customers as it encompasses the range of business sectors in this class, including: wood products, pulp/paper/paperboard mills, food products, foundries, and petroleum refining.

"Ind_1991_1997" is a binary variable that denotes the January-1991 through December-1997 timeframe where Industrial customer counts increased and then decreased very rapidly: a 23.7% increase from January-1991 to June-1994, followed by a 36.2% decrease from June-1994 to December-1997. These dramatic swings in customer counts were most likely due to accounting classifications of customers at the time and this binary variable effectively "backs-out" these points from consideration to avoid biasing the model.

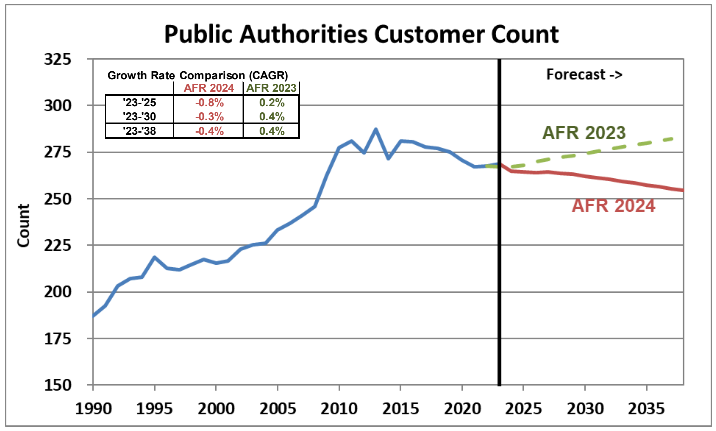
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. The MAPE has increased from 2.20 in AFR 2023 to 2.21 in the AFR 2024 model, and RMSE is unchanged at 17 from last year's model.

Figure 5: Public Authorities Customer Count – Expected Scenario

Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	139.78	0.00%	0.00%
Dum_Gov_Light_2009_2038	42.81	0.00%	0.00%
Dum_2015_2038	73.73	0.00%	0.00%
T_2015_2038	(0.23)	0.00%	0.00%
GRP_13	3.82	0.00%	0.00%



Public Auth. Customer Count		
	Count	Y/Y Growth
2011	281	
2012	275	-2.3%
2013	287	4.6%
2014	282	-1.9%
2015	281	-0.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	271	-1.5%
2021	267	-1.4%
2022	268	0.1%
2023	269	**0.5%**
2024	265	**-1.6%**
2025	264	**-0.1%**
2026	264	**-0.1%**
2027	264	**0.1%**
2028	264	**-0.2%**
2029	263	**-0.3%**
2030	262	**-0.3%**
2031	261	**-0.3%**
2032	260	**-0.4%**
2033	259	**-0.4%**
2034	258	**-0.4%**
2035	257	**-0.4%**
2036	256	**-0.4%**
2037	256	**-0.4%**
2038	255	**-0.4%**

Model Statistics	Magnitude
Adjusted R^2	96.5%
AIC	2619
Durban-Watson	0.3
MAPE	1.84
In-Sample RMSE	6.0

Model Discussion

The AFR 2024 forecast annual growth rate for public authorities customer count has increased from AFR 2023's 0.4% to now reflect a -0.4% average decrease.

The key economic driver of customer growth was 13-County Gross Regional Product (GRP). GRP is a measure of general economic health that correlates with local government revenues, and presumably local government accounts with Minnesota Power. A binary variable starting in July-2009 accounts for a step-change or "systematic shift" in the historical accounting data. The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

The combination of a binary and a trend variable for the 2015-2038 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2024) to align with the last historical year (2023). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2024 forecast value confirms this. Without these binary and trend variables, the model would project an abrupt and unreasonably large increase in customers in 2024.

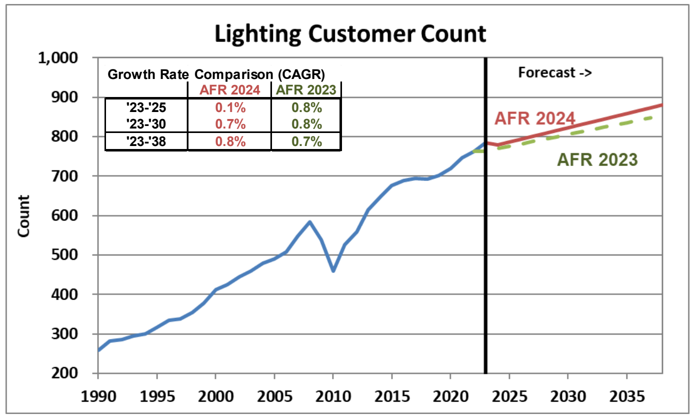
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are comparable to the AFR 2023 model: MAPE decreased slightly to 1.84 from AFR 2023's 1.89, and RMSE also decreased to 6.0 in AFR 2024 compared to 2023's 6.1.

Figure 6: Street Lighting Customer Count – Expected Scenario

Street Lighting Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	227.20	0.00%	0.00%
T	1.47	0.00%	0.00%
Light_09_14	(723.40)	0.00%	0.00%
Light_T_09_14	2.46	0.00%	0.00%
Dum_Light_2015_2038	262.37	0.00%	0.00%
T_Light_2015_2038	(0.86)	0.00%	0.00%
Light_2020_T	2.88	0.00%	0.00%



Lighting Customer Count		
	Count	Y/Y Growth
2011	527	
2012	559	6.1%
2013	615	10.0%
2014	648	5.4%
2015	677	4.5%
2016	688	1.7%
2017	695	0.9%
2018	693	-0.2%
2019	701	1.1%
2020	720	2.7%
2021	746	3.6%
2022	762	2.1%
2023	784	**2.8%**
2024	779	**-0.7%**
2025	786	**0.9%**
2026	793	**0.9%**
2027	800	**0.9%**
2028	808	**0.9%**
2029	815	**0.9%**
2030	822	**0.9%**
2031	830	**0.9%**
2032	837	**0.9%**
2033	844	**0.9%**
2034	851	**0.9%**
2035	859	**0.9%**
2036	866	**0.8%**
2037	873	**0.8%**
2038	881	**0.8%**

Model Statistics	Magnitude
Adjusted R^2	99.2%
AIC	3346
Durban-Watson	0.1
MAPE	2.61
In-Sample RMSE	14

Model Discussion

The AFR 2024 forecast annual growth rate for street lighting customer count is nearly identical to AFR 2023, increasing from 0.7% in AFR 2023 to 0.8% in AFR 2024.

A combination of a binary and trend variable starting in July-2009 account for a step-change or "systematic shift" in the historical accounting data and extends through December-2014.

A combination of a binary variable and trend variable denoting the 2015-2038 timeframe pick up where the 2009-2014 variable left off, shifting the level and trend of the estimate to align with the updated accounting data going forward.

The combination of a binary and a trend variable for the 2020-2038 timeframe (beginning early-2020) mark a shift in the level and trend of the estimate to align with recent customer growth (this was in addition to the 2015-2038 change in forecast trajectory captured by the variables above). These variables effectively shift the first forecast year (2024) to align with the last historical year (2023). Without these corrective variables, 2024 monthly forecasted values would be understated.

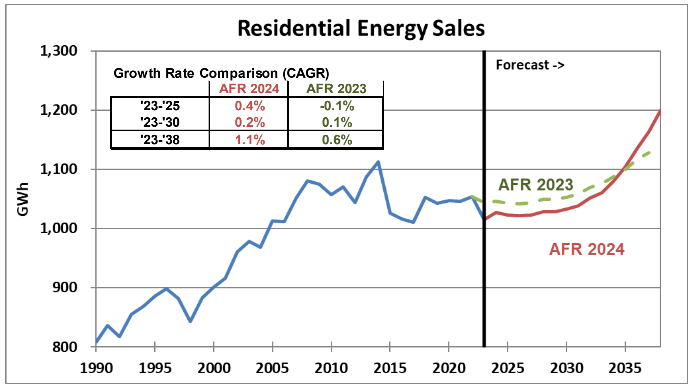
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as MAPE and RMSE are nearly identical.

Figure 7: Residential Energy Use – Expected Scenario

Residential Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	17.07	0.00%	0.00%
Feb	(1.3989039)	0.01%	0.58%
Mar	(1.9786191)	0.00%	0.00%
Apr	(1.6011437)	0.00%	0.00%
May	(1.5791483)	0.00%	0.00%
Jun	(1.2017701)	0.08%	0.00%
Oct	(2.6055470)	0.00%	0.00%
Nov	(2.1958222)	0.00%	0.00%
Dum_2008_2038	1.7123680	0.00%	0.00%
EE_Res	(0.0000150)	0.00%	0.00%
Dul_HDDpd	0.2490369	0.00%	0.00%
Dul_CDDpd	1.0347684	0.00%	0.00%



Residential Energy Sales		
	MWh	Y/Y Growth
2011	1,069,856	
2012	1,043,281	-2.5%
2013	1,086,481	4.1%
2014	1,112,579	2.4%
2015	1,026,454	-7.7%
2016	1,015,465	-1.1%
2017	1,010,955	-0.4%
2018	1,052,800	4.1%
2019	1,042,353	-1.0%
2020	1,046,910	0.4%
2021	1,046,341	-0.1%
2022	1,053,657	0.7%
2023	1,004,064	-3.6%
2024	1,027,327	1.2%
2025	1,022,502	-0.5%
2026	1,021,349	-0.1%
2027	1,022,379	0.1%
2028	1,028,339	0.6%
2029	1,028,315	0.0%
2030	1,032,462	0.4%
2031	1,038,655	0.6%
2032	1,051,307	1.2%
2033	1,060,617	0.9%
2034	1,079,267	1.8%
2035	1,103,247	2.2%
2036	1,135,054	2.9%
2037	1,163,542	2.5%
2038	1,199,628	3.1%

Model Statistics	Magnitude
Adjusted R^2	85.5%
AIC	1627
Durban-Watson	2.0
MAPE	5.45
In-Sample RMSE	1.8

Model Discussion

The graph above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of electric vehicle and distributed solar adoption.

The AFR 2024 residential per-customer use model did not use an employment or demographic indicator variable as these variables rarely correlate well with per-customer usage and often are not intuitive or explainable. Instead, the Company uses weather and seasonal binary variables to indicate month-to-month variation in sales, a time-trend to indicate long-term underlying growth, and an Energy Efficiency variable to explain recent changes (since 2007) in the underlying trend of per-customer usage growth.

The “EE_Res” variable represents the cumulative effects of all past conservation measures on each year’s sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year.

The AFR 2024 model uses simple monthly HDD and CDD (per-day) specifications. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month – this results in the “per-day” series HDDpd and CDDpd.

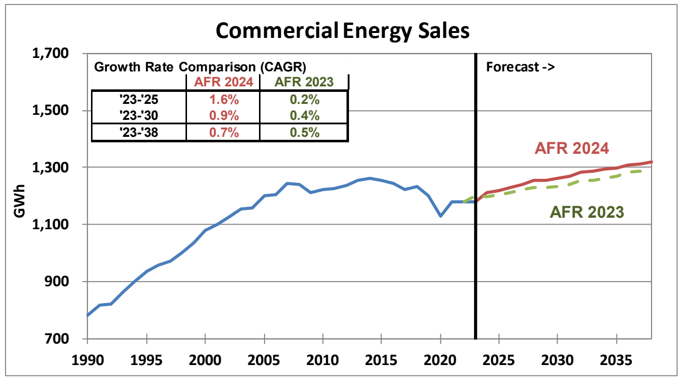
This year’s model is comparable to last year’s in terms of statistical quality. The Adjusted R-Squared indicates there’s a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values (“HAC-P-Value”) suggests all variables’ coefficients’ are significant. In-sample error metrics are similar: MAPE is 5.45% vs 5.5% in the 2023 model, and RMSE is unchanged at 1.8 compared to the 2023 model.

Figure 8: Commercial Energy Use – Expected Scenario

Commercial Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	52.42	0.00%	0.00%
Jan	(6.69)	0.04%	0.14%
Apr	(12.05)	0.00%	0.00%
May	(9.34)	0.00%	0.00%
Aug	10.61	0.00%	0.00%
Sep	7.16	0.03%	0.01%
Oct	(10.39)	0.00%	0.00%
Nov	(11.57)	0.00%	0.00%
Dum_2007_2038	3.94	0.49%	0.01%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.4608	0.00%	0.00%
Dul_CDDpd	4.04	0.00%	0.00%
EmpltoPop_13	229.23	0.00%	0.00%



Commercial Energy Sales		
	MWh	Y/Y Growth
2011	1,226,174	
2012	1,237,386	0.9%
2013	1,256,540	1.5%
2014	1,262,464	0.5%
2015	1,254,681	-0.6%
2016	1,243,045	-0.9%
2017	1,223,786	-1.5%
2018	1,233,117	0.8%
2019	1,202,403	-2.5%
2020	1,131,101	-5.9%
2021	1,181,246	4.4%
2022	1,181,683	0.0%
2023	1,178,825	0.1%
2024	1,210,954	2.4%
2025	1,219,242	0.7%
2026	1,231,776	1.0%
2027	1,241,629	0.8%
2028	1,256,379	1.2%
2029	1,257,035	0.1%
2030	1,261,194	0.3%
2031	1,271,016	0.8%
2032	1,283,584	1.0%
2033	1,286,162	0.2%
2034	1,293,535	0.6%
2035	1,299,981	0.5%
2036	1,310,508	0.8%
2037	1,313,828	0.3%
2038	1,321,005	0.5%

Model Statistics	Magnitude
Adjusted R^2	68.4%
AIC	2957
Durban-Watson	2.6
MAPE	4.57
In-Sample RMSE	9

Model Discussion

The AFR 2024 forecast of commercial energy use is higher than AFR 2023 due to forecasted higher use-per-customer. The commercial energy use forecast grows at a 0.7% per year (average) pace, compared to the AFR 2023 forecast (0.6%).

The graph above shows the final commercial energy sales outlook, which combines the econometric forecasts of use-per-customer per day and customer count, along with arithmetic adjustments for: 1) the planned installation of new generation at a specific customer's facility, and 2) the projected impacts of distributed solar adoption.

The key driver of this year's commercial energy use model was the 13-County Employment-to-Population ratio. COVID-19 resulted in a substantial loss of energy sales without any corresponding decrease in customer counts, which is unprecedented and difficult to model with the typical economic indicators. The Employment-to-Population ratio indicates the rate of employment utilization, and both correlates and explains commercial property/account energy utilization during the initial economic contraction and recovery from COVID-19.

"Dum_2007_2038" is a binary variable starting in 2007 that accounts for a step-change, or "systematic shift," in energy use for this class around the time of the 2007 Energy Act. Sales to this class have remained essentially flat since this time (aside from the COVID-19 recession of 2020).

The AFR 2024 model uses an Energy Efficiency variable as a predictor of commercial per-customer sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 68.4% indicates there's just a moderate traditional "goodness-of-fit", but this was the case in last year's model as well (Adjusted R-Squared was only 67%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power leverages other objective metrics for determining model selection such as Mean Absolute Percent Error and Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 4.57% vs. 4.5% in the 2023

Figure 9: Mining and Metals Energy Use – Expected Scenario

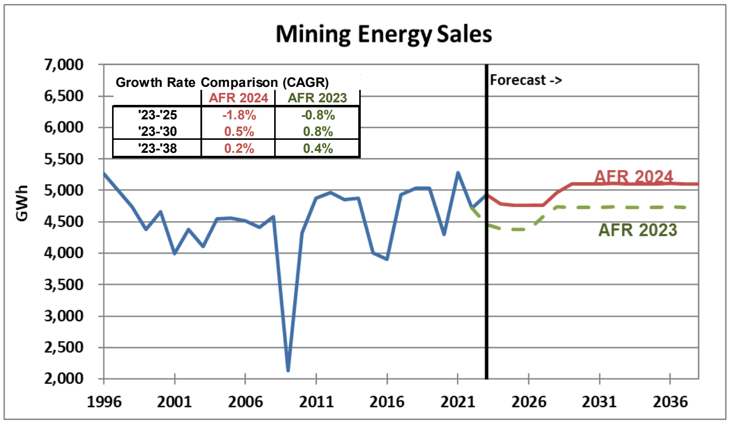
Mining and Metals Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	6,419.55	0.00%	0.00%
LTV_T	(27.43)	0.00%	0.00%
Mine_Maint	(196.44)	43.20%	27.34%
Mine_Downturn1	(3,491.96)	0.00%	0.00%
Mine_Downturn2	(1,542.14)	0.00%	0.00%
Mine_Downturn3	(1,174.41)	0.38%	0.24%
Metals	127.34	37.09%	35.83%
MN_Iron_IPI	52.37	0.00%	0.00%

Mining and Metals Energy Sales		
	MWh	Y/Y Growth
2011	4,874,331	
2012	4,968,517	1.9%
2013	4,851,094	-2.4%
2014	4,879,520	0.6%
2015	4,000,557	-18.0%
2016	3,906,570	-2.3%
2017	4,930,188	26.2%
2018	5,039,138	2.2%
2019	5,038,704	0.0%
2020	4,295,593	-14.7%
2021	5,280,743	22.9%
2022	4,712,773	-10.8%
2023	4,935,265	**4.7%**
2024	4,785,027	**-3.0%**
2025	4,758,708	**-0.6%**
2026	4,758,015	**0.0%**
2027	4,757,496	**0.0%**
2028	4,969,645	**4.5%**
2029	5,103,744	**2.7%**
2030	5,101,655	**0.0%**
2031	5,101,661	**0.0%**
2032	5,113,580	**0.2%**
2033	5,103,782	**-0.2%**
2034	5,101,717	**0.0%**
2035	5,101,749	**0.0%**
2036	5,113,694	**0.2%**
2037	5,103,919	**-0.2%**
2038	5,101,880	**0.0%**

Model Statistics	Magnitude
Adjusted R^2	71.3%
AIC	5632
Durban-Watson	0.9
MAPE	5.70
In-Sample RMSE	1018



Model Discussion

The AFR 2024 outlook for mining and metals energy use is higher than the AFR 2023 projection due to increased customer operations (post-regression adjustments). The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load adjustments.

The key economic driver of this year's mining energy use model was the Minnesota (MN) Iron IPI, which measures the real production output nationwide in the industry and is scaled to MN-only.

This year's model incorporates several binary variables to control for known or suspected definitional changes in the historical mining energy sales series. These variables have been added with the goal of avoiding bias in the IPI's coefficient for these past definitional changes in the mining and metals sales series.

"LTV_T" is a trend variable that denotes the timeframe from 1996-2001, when a large mining customer ended operations. The variable accounts for a possible change in relationship between Minnesota Power mining customer energy and the MN IPI, and allows for a more exact estimation of the relationship during the current paradigm.

The "Mine_Maint" binary variable denotes and normalizes for some of the observable seasonality in mining operations.

The "Mine_Downturn1" binary variable denotes the recession period from early 2009 to early 2010, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn2" binary variable denotes a timeframe from May-2015 to February-2017, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn3" binary variable denotes months between April-2020 and November-2020, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Metals" binary variable denotes operations of four smaller metals customers in the January-2010 to September-2016 timeframe. These customers' are backed out of the historical series prior to regression modeling, but their historical production contributed to national iron IPI. This binary variable ("Bi_Mine6") explains the temporary distortion in the energy-sales-to-National-IPI relationship.

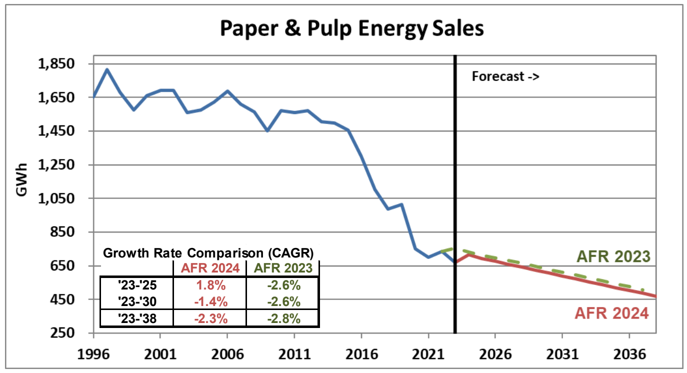
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant-with the exception of "Mine_Maint" and "Metals". It was determined this variable was needed because this variable was used in last year's model, i.e. for year-to-year consistency, and this is an important factor shaping consumption in the forecast timeframe. In-sample error metrics are similar: the MAPE is 5.7 compared to 2023 model at 4.9%, but RMSE is higher at 1018 vs. 975 in the 2023 model.

Figure 10: Paper and Pulp Products Energy Use – Expected Scenario

Paper and Pulp Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	4,699.26	0.00%	0.00%
T	(3.95)	0.00%	0.00%
Mar	131.36	16.83%	1.95%
Jun	162.24	8.92%	1.62%
Aug	280.43	0.35%	0.01%
Sep	304.00	0.17%	0.01%
Oct	261.85	0.67%	0.07%
Dec	(139.56)	14.35%	4.89%
Term_Paper_20_38	(1,521.97)	0.00%	0.00%
Paper_IPI_diff	26.34	14.89%	9.15%
Paper_22_Gen	977.44	0.47%	0.00%



Paper & Pulp Energy Sales		
	MWh	**Y/Y Growth**
2011	1,559,519	
2012	1,570,852	0.7%
2013	1,505,113	-4.2%
2014	1,498,810	-0.4%
2015	1,456,091	-2.9%
2016	1,302,920	-10.5%
2017	1,104,160	-15.3%
2018	987,208	-10.6%
2019	1,013,971	2.7%
2020	752,072	-25.8%
2021	701,549	-6.7%
2022	735,506	4.8%
2023	668,406	**-9.1%**
2024	715,022	**7.0%**
2025	693,229	**-3.0%**
2026	675,621	**-2.5%**
2027	658,337	**-2.6%**
2028	642,430	**-2.4%**
2029	624,096	**-2.9%**
2030	606,496	**-2.8%**
2031	589,220	**-2.8%**
2032	573,121	**-2.7%**
2033	554,989	**-3.2%**
2034	537,389	**-3.2%**
2035	520,113	**-3.2%**
2036	503,827	**-3.1%**
2037	485,883	**-3.6%**
2038	468,284	**-3.6%**

Model Statistics	Magnitude
Adjusted R^2	74.8%
AIC	5109
Durban-Watson	0.5
MAPE	9.40
In-Sample RMSE	466

Model Discussion

The AFR 2024 outlook for paper and wood products energy requirements is slightly lower than the AFR 2023 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The AFR 2023 model was driven by the Industrial Production Index (IPI) for Paper, which measures the real production output nationwide in the industry, and indicates an underlying secular decline of the North American Paper industry (and demand for paper products).

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's reasonable goodness-of-fit, and In-sample error metrics are a bit different: MAPE is slightly higher in AFR 2024 at 9.4 compared to 9.1 in AFR 2023, and RMSE decreased to 466 vs. 470 in the 2023 model.

The AIC indicates a highly parsimonious model. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

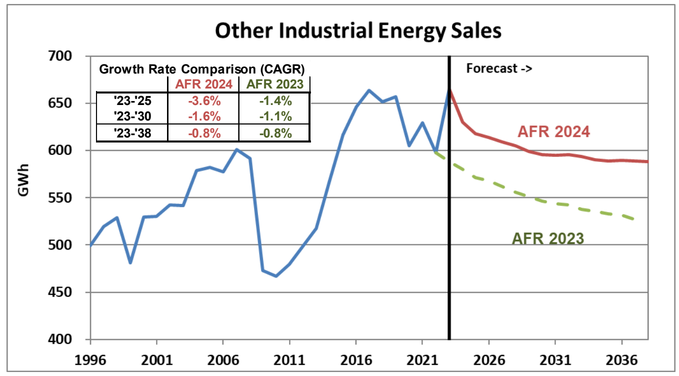
Figure 11: Other Industrial Energy Use – Expected Scenario

Other Industrial Energy Use - Expected Scenario

Estimation Start/End:	
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value

Other Industrial Energy Sales		
	MWh	Y/Y Growth
2012	498,474	
2013	517,786	3.9%
2014	568,206	9.7%
2015	616,625	8.5%
2016	646,339	4.8%
2017	663,444	2.6%
2018	651,546	-1.8%
2019	656,590	0.8%
2020	605,277	-7.8%
2021	629,017	3.9%
2022	597,430	-5.0%
2023	640,688	11.3%
2024	629,923	-5.3%
2025	617,802	-1.9%
2026	613,730	-0.7%
2027	609,354	-0.7%
2028	605,203	-0.7%
2029	599,142	-1.0%
2030	595,739	-0.6%
2031	595,220	-0.1%
2032	595,417	0.0%
2033	593,278	-0.4%
2034	590,389	-0.5%
2035	588,874	-0.3%
2036	589,668	0.1%
2037	588,895	-0.1%
2038	588,169	-0.1%



Model Discussion

Minnesota Power has broken out Other Industrial into four sectors: 1) Pipelines, 2) Foundries, 3) Food Products, and 4) Remaining.

Due to several Other Industrial sub-sectors containing just two or three customers, these sector-level forecasts could imply trade secret information. Minnesota Power will only show the aggregate of all sectors ("Other Industrial") in the graph above and table to the left. The sector-specific models of projected energy and the model discussions are discussed on the following pages, and are marked "TRADE SECRET" due to the limited number of customers in each sector.

Figure 12: Pipelines Energy Use – Expected Scenario

Pipelines Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(886.44)	0.00%	0.13%
Term_13_23	(5,176.50)	0.00%	0.00%
Term_13_23_T	18.03	0.00%	0.00%
TTU_13	0.03	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	78.1%
AIC	4050
Durban-Watson	0.6
MAPE	12.18
In-Sample RMSE	98

Model Discussion

Minnesota Power modeled and projected energy sales to pipeline customers individually, independent of total Other Industrial sales.

The AFR 2024 econometric driver for the pipelines model was 13-County Trade, Transportation, & Utilities (TTU) Employment. The TTU employment variable was selected as it directly encompasses the pipeline sector being modeled and highlights a major advantage of more granular forecasting for Other Industrial sub-sectors – economic variable specificity (last year's total Other Industrial model had 13-County Total Non-Farm Employment as the economic variable).

A binary ("Term_13_23") and a trend variable ("Term_13_23_T") denote the period in which a large pipeline customer began adding substantial load, and drove the majority of the energy use increase in the customer class. The binary and trend variables effectively "back-out" this recent load addition, so this customer's expected energy use can be addressed in isolation through a post-regression load addition to avoid double-counting.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are notably comparable to last year's model: MAPE decreased to 12.18% compared to 2023 models MAPE of 12.31%. RMSE is identical to 2023's model at 98. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 13: Foundries Energy Use – Expected Scenario

Foundries Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(422.99)	0.00%	0.01%
Foundry_1999_2000	(64.98)	0.00%	0.00%
Foundry_2011_2014	55.80	0.00%	0.00%
TotNonF_StLou	0.01	0.00%	0.00%
Foundry_IPI	1.21	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	52.2%
AIC	3278
Durban-Watson	0.9
MAPE	8.77
In-Sample RMSE	31

Model Discussion

Minnesota Power modeled and projected energy sales to foundry customers individually, independent of total Other Industrial sales.

The Foundries energy use model leveraged two economic variables: Total St. Louis County Non-Farm Employment, and IPI for Primary Metals. The IPI for Primary Metals measures the national level real output in the industry, and is the model's indicator of national demand of primary metals products. St. Louis County non-farm employment is a more granular indicator of local business operations, and explains local foundry operations that may deviate from the national trend. All of Minnesota Power's foundry customers are located in St. Louis County.

"Foundry_1999_2000" is a binary variable denoting the 1999-2000 timeframe when energy sales began decreasing ahead of the national-level Primary Metals IPI-recognized-downturn due to a local mining customer winding down operations. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

"Foundry_2011_2014" is a binary variable denoting the 2011-2014 timeframe and represents a customer that expanded operations temporarily, diverging from the national-level Primary Petals IPI. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are comparable to last year's model: MAPE is 8.77% vs 8.57% in the AFR 2023 model, and RMSE is 31, unchanged from 2023's model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 14: Food Products Energy Use – Expected Scenario

Food Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(283.15)	0.00%	0.25%
LPP_2015_2038	26.47	0.00%	0.01%
Food_IPI	4.69	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	71.9%
AIC	2888
Durban-Watson	1.2
MAPE	7.60
In-Sample RMSE	17

Model Discussion

Minnesota Power modeled and projected energy sales to food product customers individually, independent of total Other Industrial sales.

Energy sales to the food products sector was modeled using the IPI for Food Products (Food, Beverage, and Tobacco). The IPI for Food Products measures the real production output nationwide in the industry, and indicates an underlying growth trend in this class.

"LLP_2015_2038" is a binary variable denoting the 2015-2038 timeframe. This variable represents a new level of sales following period of expansion for one of the customers in this class (beginning in 2015) and continues throughout the forecast timeframe. A binary variable approach is utilized as Minnesota Power is not adjusting the econometric model in the forecast timeframe to account for increased sales.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also comparable to last year's model: MAPE is 7.60 vs. 7.67% in AFR 2023, and RMSE is 17 vs. 18 in AFR 2023 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 15: Other Industrial Remaining Energy Use – Expected Scenario

Other Industrial Remaining Energy Use - Expected Scenario

Estimation Start/End:	1/2001 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	0.66	0.00%	0.00%
Misc_Ind_2001_2002	0.34	0.00%	0.00%
Rem_2023_2038	0.09	3.30%	1.16%
MFG_StLou	0.00	12.61%	5.13%

Model Statistics	Magnitude
Adjusted R^2	22.0%
AIC	-269
Durban-Watson	2.5
MAPE	12.71
In-Sample RMSE	0.1

Model Discussion

Minnesota Power modeled and projected energy sales to other industrial: remaining customers individually, independent of total Other Industrial sales. The other industrial: remaining sub-sector includes all industrial customer usage not accounted for in: Mining, Paper, Pipelines, Foundries, and Food Product Manufacturing.

The sole econometric variable used in the other industrial remaining model was St. Louis County Manufacturing Employment. Many of the customers in this class are either directly involved in manufacturing, or supply manufacturers with the goods/inputs they need to create a finished product to sell. Several of the larger customers in this class are located in St. Louis County; because of this, Minnesota Power selected the more granular variable to inform the model, instead of a more general/broader Manufacturing employment series.

"Misc_Ind_2021_2002" is a binary that indicates months in the 2001-2002 timeframe where energy sales have erroneous values. This binary essentially removes the erroneous data points from consideration in the model as they would have a negative influence on the model's integrity.

The Adjusted R-Squared indicates there's a moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also reasonable and comparable to AFR 2023 models: MAPE is comparable to AFR 2023 at 12.71 vs. 12.88, and RMSE is similar to AFR 2023 models at just 0.1 vs. 0.02. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 16: Public Authorities Energy Use – Expected Scenario

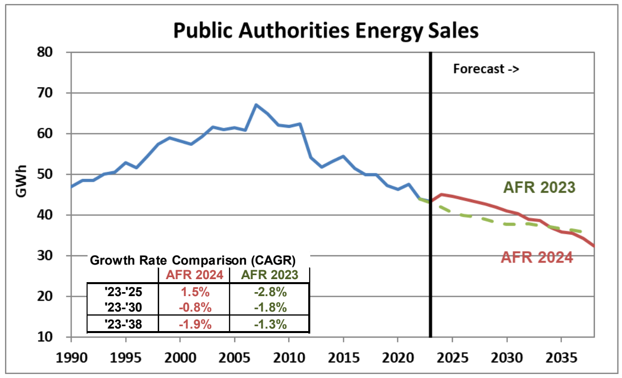
Public Authorities Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(1,215.46)	0.00%	0.00%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.16	1.41%	1.37%
Dul_CDDpd	4.24	0.00%	0.00%
MSA_Pop	4.96	0.00%	0.00%

Public Auth. Energy Sales		
	MWh	Y/Y Growth
2011	62,458	
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	53,237	2.9%
2015	54,471	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	46,375	-2.0%
2021	47,497	2.4%
2022	43,943	-7.5%
2023	43,671	**0.5%**
2024	53,252	**-1.6%**
2025	52,811	**-0.1%**
2026	52,234	**-0.1%**
2027	51,520	**0.1%**
2028	51,051	**-0.2%**
2029	50,225	**-0.3%**
2030	49,216	**-0.3%**
2031	48,592	**-0.3%**
2032	47,336	**-0.4%**
2033	46,924	**-0.4%**
2034	45,187	**-0.4%**
2035	44,070	**-0.4%**
2036	43,869	**-0.4%**
2037	42,593	**-0.4%**
2038	40,755	**-0.4%**

Model Statistics	Magnitude
Adjusted R^2	40.9%
AIC	3596
Durban-Watson	2.0
MAPE	10.35
In-Sample RMSE	20



Model Discussion

The key economic driver of this year's Public Authorities energy use model was Duluth MSA Population. This variable indicates the underlying growth trend, which impacts government entities' operations (affecting energy use).

The AFR 2024 model uses an Energy Efficiency variable as a predictor of public authorities' energy sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The commercial-sector energy efficiency variable was used for the public authorities model since: 1) both customer groups are served by the same CIP program, and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.

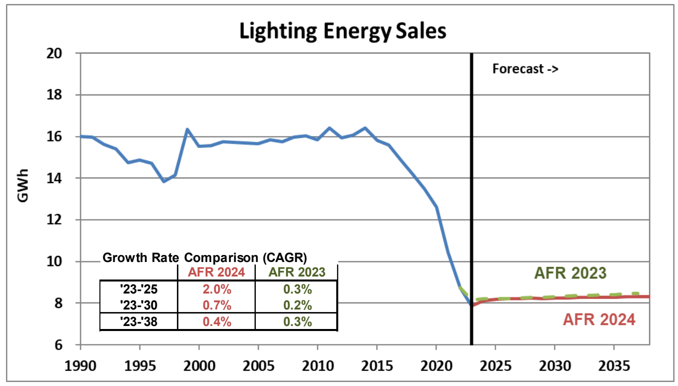
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 10.35% vs. 10.51% in the 2023 model, and RMSE is unchanged at 20 in the 2024 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 17: Street Lighting Energy Use – Expected Scenario

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2023
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	50.12	0.00%	0.00%
T	(0.01)	4.22%	5.40%
Jan	2.75	0.48%	0.11%
Feb	(2.00)	4.02%	0.58%
Mar	(9.17)	0.00%	0.00%
Apr	(13.87)	0.00%	0.00%
May	(19.70)	0.00%	0.00%
Jun	(22.80)	0.00%	0.00%
Jul	(22.40)	0.00%	0.00%
Aug	(18.95)	0.00%	0.00%
Sep	(11.57)	0.00%	0.00%
Oct	(8.30)	0.00%	0.00%
Nov	(2.87)	0.33%	0.00%
Dum_Light_1990_1999	(2.55)	0.25%	1.64%
LED_Lighting	104.37	0.00%	0.00%
LED_Lighting_T	(0.32)	0.00%	0.00%
NonWPI_StLou	0.002	1.90%	1.96%



Lighting Energy Sales		
	MWh	**Y/Y Growth**
2011	16,420	
2012	15,954	-2.8%
2013	16,066	0.7%
2014	16,400	2.1%
2015	15,801	-3.7%
2016	15,588	-1.4%
2017	14,873	-4.6%
2018	14,206	-4.5%
2019	13,482	-5.1%
2020	12,617	-6.4%
2021	10,445	-17.2%
2022	8,744	-16.3%
2023	7,864	**-10.1%**
2024	8,117	**3.2%**
2025	8,178	**0.8%**
2026	8,204	**0.3%**
2027	8,214	**0.1%**
2028	8,252	**0.5%**
2029	8,232	**-0.2%**
2030	8,247	**0.2%**
2031	8,254	**0.1%**
2032	8,291	**0.5%**
2033	8,266	**-0.3%**
2034	8,267	**0.0%**
2035	8,266	**0.0%**
2036	8,320	**0.6%**
2037	8,305	**-0.2%**
2038	8,316	**0.1%**

Model Statistics	Magnitude
Adjusted R^2	87.1%
AIC	2304
Durban-Watson	1.6
MAPE	5.97
In-Sample RMSE	4

Model Discussion

The AFR 2024 lighting per-day use model utilized St. Louis County Non-Wage Personal Income as a key economic/demographic indicator.

"Dum_Light_1990_1999" is a binary variable denoting the 1990-1999 timeframe and effectively shifts the level of the estimate to account for changes to the Company's accounting practices, which affected historical energy use data. The corrective binary shifts the forecast to avoid improbably changes in energy use, but does not impact the forecast trajectory; this is determined by the economic variables.

"LED_Lighting" and "LED_Lighting_T" are binary and trend variables denoting the 2017-2038 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2017 (this level is then held constant in the forecast timeframe after January-2024). This binary and trend combination shifts the forecast to account for Minnesota Power's LED lighting program's impact on energy use, and unlike "Dum_Light_1990_1999," it does impact the forecast trajectory; in addition to the economic variables.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 5.97% vs. 5.46% in the 2023 model, and RMSE is 4.0, the same as AFR 2023. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 18: Resale Energy Use – Expected Scenario

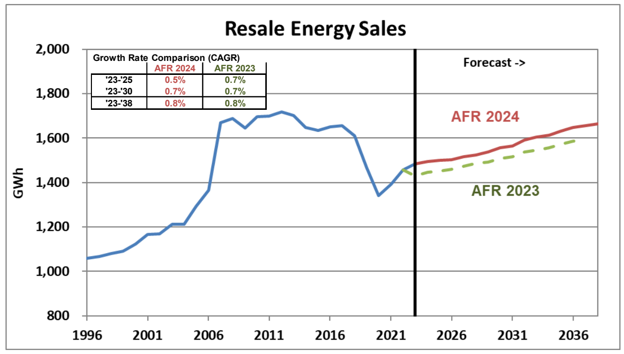
Resale Energy Use - Expected Scenario

Estimation Start/End:

Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF

Resale Energy Sales		
	MWh	Y/Y Growth
2012	1,718,819	
2013	1,700,993	7.2%
2014	1,585,993	3.3%
2015	1,634,786	3.1%
2016	1,649,405	0.9%
2017	1,656,865	0.5%
2018	1,610,792	-2.8%
2019	1,468,108	-8.9%
2020	1,340,290	-8.7%
2021	1,393,315	4.0%
2022	1,456,237	4.5%
2023	1,487,350	2.0%
2024	1,494,960	**0.7%**
2025	1,500,937	**0.4%**
2026	1,502,058	**1.5%**
2027	1,515,468	**0.9%**
2028	1,523,137	**0.5%**
2029	1,538,527	**1.0%**
2030	1,556,692	**0.7%**
2031	1,564,390	**0.5%**
2032	1,590,144	**1.6%**
2033	1,604,371	**1.0%**
2034	1,613,035	**0.5%**
2035	1,632,590	**1.2%**
2036	1,646,716	**0.9%**
2037	1,655,505	**0.5%**
2038	1,664,267	**0.5%**



Model Discussion

AFR 2024 is continuing the practice of forecasting each resale customer separately. Minnesota Power will not be providing graphs or tables that include forecast values for individual resale customers (similar to the approach mentioned above for Other Industrial).

Due to the trade secret nature of individual resale customers' forecasts, Minnesota Power will only be showing the aggregate forecast summary for total Resale energy sales in the graph above and table to the left.

Figure 19: System Peak Demand – Expected Scenario

System Peak Demand - Expected Scenario

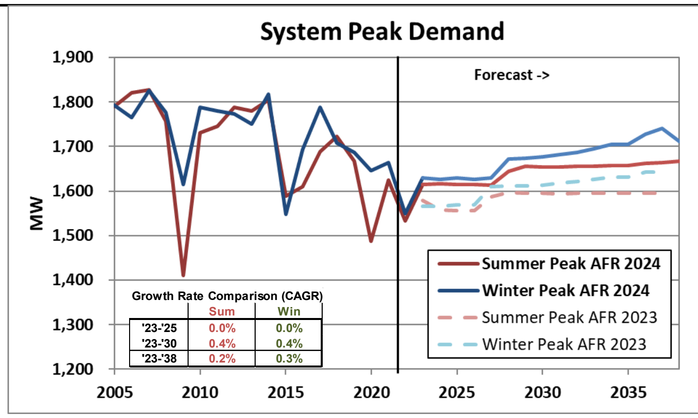
Estimation Start/End:	6/1999 - 12/2023
Unit Modeled/Forecast:	Monthly Peak Demand

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	364.25	0.00%	0.00%
WN_MWhpd	0.04	0.00%	0.00%
S	37.74	0.00%	0.02%
W	18.92	2.80%	0.30%
WC_THI	(1.17)	0.00%	0.00%
WC_THI_3	0.00	0.00%	0.00%
Dum_1999_2001	(21.17)	0.47%	0.49%
Dum_2008	115.6396	0.00%	0.00%
Dum_2017_2036	26.972	0.00%	0.00%
Jan_WN_MWhpd	(0.001)	2.71%	0.24%
Feb_WN_MWhpd	(0.001)	1.09%	0.04%
Mar_WN_MWhpd	(0.001)	0.07%	0.00%

System Peak Demand

	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2013	1,781		2013	1,751	
2014	1,805	1.4%	2014	1,818	3.8%
2015	1,589	-11.9%	2015	1,547	-14.9%
2016	1,610	1.3%	2016	1,693	9.4%
2017	1,688	4.9%	2017	1,789	5.6%
2018	1,724	2.1%	2018	1,707	-4.5%
2019	1,668	-3.2%	2019	1,687	-1.2%
2020	1,487	-10.8%	2020	1,646	-2.4%
2021	1,625	9.3%	2021	1,663	1.1%
2022	1,533	-5.6%	2022	1,550	-6.8%
2023	1,614	5.3%	2023	1,630	5.2%
2024	1,616	**0.1%**	2024	1,626	**-0.2%**
2025	1,615	**-0.1%**	2025	1,629	**0.2%**
2026	1,615	**0.0%**	2026	1,626	**-0.2%**
2027	1,612	**-0.1%**	2027	1,629	**0.2%**
2028	1,644	**2.0%**	2028	1,673	**2.7%**
2029	1,655	**0.7%**	2029	1,674	**0.1%**
2030	1,655	**0.0%**	2030	1,677	**0.1%**
2031	1,654	**0.0%**	2031	1,681	**0.3%**
2032	1,655	**0.1%**	2032	1,687	**0.3%**
2033	1,657	**0.1%**	2033	1,694	**0.4%**
2034	1,657	**0.0%**	2034	1,705	**0.6%**
2035	1,660	**0.1%**	2035	1,715	**0.6%**
2036	1,662	**0.1%**	2036	1,728	**0.7%**
2037	1,664	**0.2%**	2037	1,741	**0.8%**
2038	1,667	**0.2%**	2038	1,711	**-1.8%**

Model Statistics	Magnitude
Adjusted R^2	89.8%
AIC	2908
Durban-Watson	1.7
MAPE	1.81
In-Sample RMSE	33



Growth Rate Comparison (CAGR)

	Sum	Win
'23-'25	0.0%	0.0%
'23-'30	0.4%	0.4%
'23-'38	0.2%	0.3%

Model Discussion

The long-run outlook for Minnesota Power's system peak is higher than the 2023 outlook primarily due to a projected increase in industrial energy consumption relative to AFR 2023.

Temperature variables play a critical role in peak demand modeling, and both the definition and structure of these variables are important for interpreting the results. 2024 AFR used a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index. Peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

The 2024 AFR peak demand model utilized two binaries to indicate the month of the system's historical summer and winter peaks, and assumed this peak in July/January (respectively) throughout the forecast timeframe. Summer peaks typically occur in either July or August, historical winter peaks have occurred in November, December, February, but are most likely in January. This broad distribution of peak occurrence dilutes the model's measured seasonality, and as a result, the peak forecast will understate both the summer and winter peak demand figures. The utilization of these peak binaries focuses the seasonal peaks – which may have occurred in August or July, or December or January - into the months of July and January. This ensures seasonal peaks are not under forecast as a result of historical diversity in the timing of those seasonal peaks.

The model also includes two binaries ("Dum_1999_2001" and "Dum_2008") denoting periods of economic downturn for Minnesota Power's large industrial customers, resulting in abnormally low usage. During (or immediately following) these periods the normal relationship of Peak-to-Energy was affected by the idling of large, high load factor customers. These binaries effectively remove these downturn periods from consideration in the regression model and allow for more accurate estimation of model coefficients under more normal economic conditions.

There is no energy efficiency variable in the peak demand model and no explicit assumption for peak demand savings. Conservation impacts are accounted for by leveraging the energy sales forecast, which includes the effects of conservations, as the key input to the peak demand regression model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are very similar to the 2023 model: MAPE is 1.81% vs. 1.9% in the 2023 model, and RMSE is 33 vs. 34 in the 2023 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

D. Forecast Confidence and Historical Accuracy (7610.0320, Subp. 1.E and Subp. 1.F)

Minnesota Power has a strong record of both accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), as well as the 2020 COVID-19 recession (including 2021), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.034 percent over the prior year.

Figures 20 through 22 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, in Figure 20 the bottom value of -15.7 percent in the 2020 column is the difference between the forecast produced in 2020 (AFR 2020) and the 2020 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2015 (formulated in 2015) forecast of 2016 was 5.9 percent (581 GWh) above the actual (due to effects of the Mining downturn).

Figure 20: AFR Forecast Accuracy – Aggregate System Energy

Total Energy Sales Forecast Error

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AFR 2000	**-3.9%**	**1.5%**	0.5%	1.9%	-0.6%	**-2.2%**	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%									
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	**-4.1%**	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%								
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%							
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	**-2.7%**	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.8%	12.5%						
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%					
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%				
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%	38.1%			
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%	31.6%	18.6%		
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%	32.1%	19.5%	26.9%	
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	8.5%	10.2%	13.4%	30.2%	17.5%	24.3%	22.4%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	1.1%	**11.6%**	15.2%	6.9%	7.7%	10.1%	26.1%	13.8%	20.5%	18.8%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	7.5%	8.4%	10.8%	26.9%	14.4%	21.0%	19.3%
AFR 2012													**-1.4%**	***0.5%***	0.7%	11.5%	15.4%	**6.9%**	7.8%	10.2%	26.4%	13.9%	20.5%	18.8%
AFR 2013														**-0.2%**	***2.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	40.2%	26.2%	33.4%	31.2%
AFR 2014															**-0.3%**	***13.9%***	24.2%	13.9%	14.9%	**17.2%**	34.0%	20.3%	27.0%	24.8%
AFR 2015																**2.4%**	***5.9%***	9.9%	11.0%	13.1%	**29.4%**	16.3%	22.6%	20.5%
AFR 2016																	**-1.4%**	***-4.3%***	-2.9%	-2.2%	20.4%	**10.1%**	19.3%	17.5%
AFR 2017																		**1.8%**	***2.5%***	3.6%	24.2%	13.1%	**19.3%**	**17.4%**
AFR 2018																			**1.4%**	***1.7%***	20.4%	9.7%	16.7%	**14.7%**
AFR 2019																				**-1.8%**	***14.7%***	4.2%	12.1%	11.6%
AFR 2020																					**-15.7%**	***-7.8%***	-2.2%	-4.3%
AFR 2021																						**-8.7%**	***-2.7%***	***-3.2%***
AFR 2022																							**-1.2%**	***-1.3%***
AFR 2023																								**-4.8%**

Figure 21: AFR Forecast Accuracy – Summer Peak

Summer System Peak Error

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.1%									
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.6%	17.4%								
AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	2.3%	16.7%	16.9%							
AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-2.0%	12.4%	12.0%	7.5%						
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%	6.3%	22.5%	22.7%	18.4%	17.5%					
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%	5.2%	21.3%	22.8%	19.2%	19.1%	25.6%				
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%	7.0%	22.0%	22.0%	17.1%	15.2%	20.0%	35.2%			
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.4%	18.1%	33.4%	23.0%		
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.6%	16.3%	31.6%	21.6%	30.2%	24.8%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	2.0%	1.1%	6.1%	20.9%	12.2%	20.5%	16.0%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.7%	5.1%	9.3%	23.4%	13.6%	21.2%	15.8%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.9%	9.2%	23.3%	13.6%	21.2%	15.8%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	3.1%	7.3%	21.2%	11.7%	19.3%	14.1%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.5%	18.0%	32.9%	22.2%	30.2%	24.2%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.3%	17.6%	32.5%	21.6%	29.3%	23.2%
AFR 2015																1.0%	5.4%	10.6%	10.6%	14.9%	29.4%	18.9%	26.4%	20.6%
AFR 2016																	-1.4%	1.0%	0.0%	1.6%	24.0%	16.2%	23.9%	18.3%
AFR 2017																		4.5%	2.2%	4.0%	20.0%	11.1%	18.1%	12.8%
AFR 2018																			-0.6%	0.9%	15.4%	7.6%	14.8%	9.7%
AFR 2019																				-1.1%	11.4%	3.2%	12.1%	7.6%
AFR 2020																					-17.7%	-4.9%	1.3%	-3.9%
AFR 2021																						-6.3%	0.8%	-3.5%
AFR 2022																							3.9%	1.2%
AFR 2023																								-2.2%

Figure 22: AFR Forecast Accuracy – Winter Peak

Winter System Peak Error

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AFR 2000	0.4%	-1.0%	-2.6%	-4.1%	-6.2%	-5.7%	-3.6%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	1.8%	-1.1%									
AFR 2001		5.8%	3.1%	1.1%	-1.6%	-1.6%	0.2%	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	5.5%	2.5%	21.4%								
AFR 2002			1.1%	0.2%	-1.6%	-0.9%	1.3%	-1.3%	2.0%	15.1%	0.2%	1.8%	2.8%	4.9%	1.7%	20.1%	11.2%							
AFR 2003				-5.2%	-7.4%	-6.7%	-4.4%	-6.6%	-3.1%	9.0%	-4.1%	-2.1%	-0.3%	2.4%	-0.2%	18.4%	10.2%	5.7%						
AFR 2004					-5.0%	-4.3%	-0.9%	-3.6%	4.2%	16.6%	1.9%	5.1%	7.6%	11.2%	8.9%	29.9%	21.4%	16.9%	24.5%					
AFR 2005						-3.8%	-1.5%	-3.9%	3.2%	15.8%	1.2%	2.9%	4.4%	7.5%	5.1%	25.2%	17.0%	12.5%	19.9%	23.3%				
AFR 2006							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.9%	17.9%	20.1%	23.7%			
AFR 2007								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.5%	12.8%	15.5%	19.8%	19.8%		
AFR 2008									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.8%	15.4%	18.3%	22.8%	23.1%	35.4%	30.3%
AFR 2009										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.5%	7.8%	10.8%	15.1%	15.3%	26.6%	21.8%
AFR 2010											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	3.2%	8.7%	10.6%	14.0%	13.4%	23.7%	18.2%
AFR 2011												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.5%	9.2%	11.2%	14.7%	14.3%	24.7%	19.3%
AFR 2012													0.1%	1.3%	-1.9%	15.8%	7.1%	2.0%	7.6%	9.6%	13.1%	12.6%	23.0%	17.6%
AFR 2013														0.4%	1.5%	20.5%	16.5%	11.0%	16.9%	19.0%	22.5%	21.8%	32.8%	26.8%
AFR 2014															-2.7%	24.2%	15.7%	10.3%	15.9%	17.9%	21.3%	20.4%	31.1%	25.1%
AFR 2015																10.3%	10.5%	8.1%	13.8%	15.8%	19.3%	18.6%	29.1%	23.1%
AFR 2016																	1.8%	-2.8%	2.1%	4.8%	11.4%	15.1%	25.7%	19.8%
AFR 2017																		0.1%	4.8%	5.3%	11.1%	10.4%	20.4%	14.5%
AFR 2018																			1.7%	3.2%	6.4%	7.8%	17.3%	11.7%
AFR 2019																				-1.0%	2.8%	2.3%	14.3%	9.0%
AFR 2020																					-7.2%	-6.0%	1.8%	-3.3%
AFR 2021																						-7.0%	0.9%	-3.3%
AFR 2022																							7.1%	1.7%
AFR 2023																								0.9%

E. Methodology Strengths and Weaknesses and Suitability to the System (7610.0320, Subp. 1.F)

The Company's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads or new technology adoption. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook and capturing the historical and projected effects of energy efficiency. However, a fully econometric process would not reflect any of the substantial industrial expansions that are likely in the Minnesota Power service territory. A combined "econometric/large customer load addition" approach produces the most reasonable forecast.

The Company's econometric modeling process has two key strengths: it is both highly replicable, and adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

That said, there are some weaknesses to a combined "econometric/large customer load addition" approach. For instance, there is some subjectivity in the perceived likelihood of individual large customer load additions/losses since their magnitude or timing is difficult to estimate in a probabilistic way. To minimize subjectivity on the part of Minnesota Power, the Company utilizes information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power's system demand and energy sales at any given point in time. The Company addresses this potential for error by maintaining close contact with existing and potential customers to keep current on their plans.

F. Data Requirements (7610.0320, Subp. 1.F)

Data used in Minnesota Power's forecast can be broadly categorized as follows:

- *Historical quantities of the variables to be forecast,* which consists of energy sales and customer counts for Minnesota Power's defined customer classes, energy sales, and peak demand.
- *Regional Demographic and Economic data:*
  - *Duluth Metropolitan Statistical Area (MSA)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
  - *Aggregate 13-County Minnesota Power service territory (13-Co)* consists of population, Gross Regional Product (a Regional GDP metric), sector-specific employment, and income metrics.
  - *Individual 13-County Minnesota Power service territory (13-Co)* consists of sector-specific employment and income metrics for each individual County.
- *Indicators of National economic activity* such as the Industrial Production Indexes (IPI) or Macroeconomic indicators such as U.S. GDP or Unemployment.

- *Weather and related data* including heating degree days (HDD), cooling degree days (CDD), temperature, humidity, dew point, and wind speed.
- *Electricity and Alternative Fuel prices*, which includes the price of electricity, natural gas, and heating oil by sector for the Minnesota Power service territory.

II. Forecast Data Inputs & Adjustments

A. Forecast Database Inputs (7610.0320, Subp. 2.A)

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground (WU).[1] Minnesota Power utilizes Monthly HDDs and CDDs in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This results in the “per-day” series HDDpd and CDDpd.

Normalizing the series by transforming to a per-day unit allows for a more accurate estimate of the weather’s impact on energy sales. The forecast assumes more than a twenty-year historical average for each month (Jan 2001 – Dec 2023).

Temperature, humidity, and wind-chill data used to model peak demand are derived from Schneider Electric. In previous forecasts, the Company has leveraged either NOAA or WU for daily or monthly-frequency values. The AFR 2024 forecast database features weather observations that are specific to the historical peak hour (i.e., the temperature, humidity, and wind-chill at the time of the peak). This closer alignment between the peak demands and the weather that induced them should produce a more accurate estimate of weather-sensitivity and a more accurate forecast of future peak demand.

Development of the historical weather series begins by establishing the date and time of historical monthly peaks. Weather observations for these date/times is then gathered and organized into a monthly-frequency weather series.

[1] http://www.wunderground.com/.

A Temperature-Humidity Index (THI)[2] is utilized to consider the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 75 degrees. A Wind-Chill (WC) index[3] was also utilized to capture the cold temperatures and, when applicable, the cooling effects of wind speed. The WC index is only applicable when temperatures drop below 40 degrees and wind speeds are greater than 3 miles per hour.

IHS Global Insight

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[4] A single source for National, Metropolitan Statistical Area (MSA), and County-level outlooks ensures internal consistency of forecast assumptions.

IHS Global Insights data development process begins with producing a national-level forecast. County-level and MSA data for Northeast Minnesota is then calculated through a "Top-down/Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels.

IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect the historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Regional Economic Models, Inc. (REMI)

Minnesota Power subscribes to the latest REMI Policy Insight version (PI+) for northeastern Minnesota. This input/output econometric simulation software combines a national economic outlook[5] with specified regional economic conditions to produce a forecast for a 13-County

2 http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
3 http://www.nws.noaa.gov/os/windchill/index.shtml.
4 With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.
5 Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook.

Planning Area such as employment by sector, population, economic output by sector, and Gross Regional Product (GRP).

For AFR 2024, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e., expansions and layoffs/closures) to produce an expected economic outlook for the region.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and GRP are not provided by IHS Global Insight for the 13-County Planning area. These series are derived directly from REMI outputs and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Like IHS Global Insight, REMI relies on data from public sources that are subject to revision. These revised data inputs result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

<u>Indexes of Industrial Production (IPI series)</u>

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2017 in this case (that is, 2017 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are, therefore, ideal for forecasting future energy sales to the class.

The historical national-level IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are explained on the Federal Reserve's website.[6]

Forecasts for each national-level IPI were developed from the projections of national-level economic indicators from IHS Global Insight, and are, therefore, consistent with all other AFR

[6] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.

2023 forecast assumptions. These macroeconomic drivers are used to model and forecast the national-level IPI series.

The historical Minnesota iron IPI was developed using actual iron ore production data from the U.S. Geological Survey website (USGS).[7] The projected Minnesota iron IPI was developed by scaling the national-level Iron IPI forecast using an assumption of the industry's composition going forward. Minnesota now comprises about 83 percent of U.S. product, so the Minnesota iron IPI equals the national-level IPI x 0.83. The entire historical and forecast Minnesota iron IPI was then indexed to 2012 for consistency with past AFRs, the other IPI series used in AFR 2024, and the U.S. Federal Reserve's current standard index year.

Energy Prices

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in the Company's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy (DOE) and Energy Information Administration (EIA). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook (AEO) is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central (WNC) region, and the national total. Minnesota Power's historical average electric price data are from the Company's FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2017 base year GDP implicit price deflator (IPD).

B. Forecast Adjustments (7610.0320, Subp. 2.B)

1. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2024, which fall into three general categories:

a. **Adjustments to raw customer count data for billing anomalies:** Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts. Where there is a systemic shift (e.g., seasonal billing in residential customers count),

[7] https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/.

Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are fewer than three consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

b. **Adjustments to raw sales and peak demand data for large load additions and losses**: All adjustments to the historical database are described below in detail and organized by sector:

[TRADE SECRET DATA BEGINS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] TRADE SECRET DATA ENDS]

2. Adjustments to Econometric Forecast

Minnesota Power's forecast scenario is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These adjustments fall into the following categories:

a. **Net Load/Energy Added**: are exogenous adjustments for load added due to Distributed Solar Generation, Electric Vehicle impacts, new customers or expansion by existing customers, and lost load due to closure, loss of contract, or reduced industry operating levels. This variability and average operating levels are expected over the forecast period and are taken into account as a normalized adjustment to a representative level in the forecast. This adjustment includes all load added or lost on the system, regardless of how that load is met; "Net Load/Energy Added" accounts for any change in load at the system level. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values.

b. Customer Generation: is the demand on Minnesota Power system that is met by customer owned generation. Customer generation can fluctuate without clear economic causes, so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in three steps:

- Remove Customer Generation from the historical peak series.
- Econometrically project a less volatile "FERC load coincident w/Monthly Minnesota Power System peak (MW)" monthly peak series.
- Arithmetically account for Customer Generation after forecasting.

c. Dual Fuel: Minnesota Power has a demand response program for residential and commercial customers. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruptions as a resource and not as an adjustment to the load forecast.

d. Electric Vehicles: There are two components of the Electric Vehicle (EV) energy forecast: 1) The EV saturation rate of the total light-weight vehicles in Minnesota Power service territory and 2) the energy requirements per vehicle.

First, Minnesota Power estimated its current EV saturation rate of all light-weight vehicles in its service territory. Currently, there are 500 known electric vehicles in Minnesota Power's service territory,[8]. This equates to a 0.24 percent saturation rate of the total light-weight vehicles. To-date, this saturation rate trails the national average electric vehicle adoption rate by about eight years. The Company then identified an updated publicly available forecast that considers recent industry trends and legislative action that incentivizes EVs. The EV adoption rate forecast for the Minnesota Power service territory follows Goldman Sachs's projected national adoption rate,[9] but lagged by about eight years. The Company attributes this lag in adoption to issues of income,

8 https://mn.gov/puc/activities/economic-analysis/electric-vehicles/

9 https://www.goldmansachs.com/intelligence/pages/electric-vehicles-are-forecast-to-be-half-of-global-car-sales-by-2035.html#:~:

population density/cost-efficiency of commercial charging station locations, and reduced efficiency in cold-weather. The annual saturation rate outlook is then multiplied by the estimated number of light-weight vehicles in Minnesota Power's service territory [10] to estimate the total number of EVs.

The annual EV energy requirements forecast was calculated by multiplying the EV count and an estimate of per-unit energy requirements, which the Company assumes is about 3,262 kWh per year.[11] The Company did not attempt to modify this annual energy requirement estimate per regional commute distances or regional climate and related efficiency; both estimates would involve comparisons of national and regional characteristics that are difficult to make at this early stage of adoption. However, the Company did leverage regional temperature information to impart a seasonal (i.e., monthly) distribution to the overall annual EV energy requirements estimates.

Identifying the impact of EV charging on monthly peak demand requires information on charging patterns/characteristics – i.e., how/when customers will tend to charge their vehicles. A National Renewable Energy Laboratory (NREL) value assessment study of electric vehicles[12] contained modeled EV charging patterns for several customer types. For the purposes of determining EV charging load coincident with the system peak demand, Minnesota Power assumed the charging profile representative of level 1 charging, at a -single-family dwelling, with *no* Time of Use (TOU) restriction or rate.

Under the AFR 2024 expected scenario, Minnesota Power customers own about 56,369 EVs (approximately 24.5% saturation rate of light-weight vehicles in Minnesota Power service territory) and the added energy requirements from post-2022 EV adoption increases to about 182,200 MWh. This level of EV ownership would increase summer peak coincident demand by about 23 MW and winter peak demand by 67 MW.

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[10] Count of Standard Residential and All Electric accounts – excludes Dual Fuel and Controlled Access to avoid double counting and inflating the estimate of households served.

[11] General Motors estimates the annual energy use of a Chevy Volt is 2,520 kWh – https://www.energy.gov/eere/electricvehicles/charging-home – Rough estimates of energy requirements based on regional commuting distances and 33 kWh per 100 miles (Nissan Leaf rated efficiency) produced 2,580 kWh, so the Chevy Volt estimate is likely an accurate enough assumption for long-term forecasting.

e. **Distributed Generation** (DG): The process of forecasting DG solar generation involves two separate assumptions: 1) the rate of adoption (i.e., number of new installations each year), and 2) the average size of those new installations. Minnesota Power continued to use the following methodology for the rate of adoption to use the publicly available US Energy Information Administrations distributed residential solar generation forecast for AFR 2024. The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class. Minnesota Power then calculated estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11 percent capacity factor assumption for new distributed installations.

   Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that is likely during a specific month's likely peak time (i.e., historical median peak hour) using a simulated hourly solar production curve. Minnesota Power typically peaks at 6:00 or 7:00 PM (well after sunset) in winter months, so DG solar at the time of the peak is zero percent and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3:00 or 4:00 PM when DG solar is on average 55 percent of installed capacity (the effective load carrying capacity or ELCC is 0.55).

III. Overview of Key Assumptions (7610.0320, Subp. 3)

A. National Economic Assumptions

The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales.

B. Regional Economic Assumptions

The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the "13-County Planning Area." Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas County in Wisconsin).

The 13-County Planning Area's Gross Regional Product is forecasted to average 0.2 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages 1.4 percent per-year in the forecast timeframe. Population for the 13-County Planning Area grows at about 2.1 percent in the forecast timeframe and the Duluth MSA area population remains consistent with current levels.

IV. Subject of Assumption (7610.0320, Subp. 4)

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
  - *Minnesota Power makes no assumptions regarding the availability of alternative sources of energy*.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
  - *Minnesota Power makes no assumptions regarding the expected conversion from one fuel source to another*.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
  - *See Section II.A.*
- Assumptions made in arriving at the data requested (historical reporting).
  - *Minnesota Power makes no such assumptions*.
- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand and assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Federal or State legislation.

  Minnesota Power uses energy efficiency as an input variable to the regression models, referred to as "EE as RHS var" or "Energy Efficiency as a Right-Hand Side Variable."

The "EE as RHS var" methodology has several advantages over other common energy efficiency forecasting methodologies:

- *Avoids double-counting energy efficiency impacts in the forecast timeframe.*
- *Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.*
- *Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.*
- *Doesn't require after-the-fact adjustments to econometric outputs: the energy sales forecasts already contain the effects of energy efficiency.*

An "Energy Efficiency" variable explains recent trends in customer consumption that cannot be explained by economic, demographic, or weather effects. Further, this method allows the Company to quantify the volume of energy efficiency embedded in the load forecast.

Development of the "Energy Efficiency" variable began by gathering savings data for each retail customer class, Superior Water Light and Power, and the Company's 14 Minnesota municipal customers. Incremental (i.e., first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Historical incremental savings data for Minnesota Power was obtained from the Company's past annual energy efficiency compliance filings, Minnesota Municipal customers' historical savings information was obtained from CIP results filed with the Department of Commerce.[13] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

Forecast assumptions for Minnesota Power's residential and commercial savings were derived from the Company's most recent preliminary estimates of achieved and energy savings assumptions beyond 2023, were based on the Company's 2024-2026 Triennial ECO Plan Filing.

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings to produce a "cumulative energy savings"

[13] Historical achievements filed in Docket No. E-999/PR-22-24

series.[14] *This cumulative series is the optimal variable format/definition for modeling energy sales. A cumulative savings metric represents the lasting impacts of conservation programs by aggregating or cumulating the savings from all past conservation measures. Minnesota Power used an annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authority classes, as well as three of the Company's 14 resale customers modeled in AFR 2024.*

- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
  - *Minnesota Power makes no assumptions regarding current and future saturation levels of appliances and electric space heating*.

V. Coordination of Forecasts with Other Systems (7610.0320, Subp.5)

Minnesota Power is a member of the Midwest Reliability Organization (MRO), Midcontinent Independent System Operator (MISO), Edison Electric Institute (EEI), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

VI. Load Growth Forecast Planning Scenario

U.S. electric demand is expected to grow over the next decade due to policy focused on sustainability through electrification, onshoring of industrial manufacturing, and expansion in data processing capabilities. Minnesota Power is currently seeing interest in electrification, data centers, and green steel manufacturing opportunities, and is including a scenario in this AFR for substantial load growth representative of the possible opportunities for expansion of these technologies and customers in the region. These elements will be monitored on an ongoing basis and will be updated as needed as part of the forecast outlook for this filing and associated planning processes.

[14] Using internal estimates of Minnesota Power's past programs' life of measures. A Life of Measure (LoM) is the approximate time a conservation measure will reduce energy consumption. Most conservation measures have a 10- to 20-year life. A portfolio from any particular program year will contain measures that end earlier than others, so the overall impact of measures implemented in a program year will fade over time.

Electrification

In 2021, the Energy Conservation and Optimization Act was signed into law. ECO allows for streamlining of efficient fuel switching, which includes technologies such as air source heat pumps to replace fossil fueled heating technologies, supporting the probability of increased electricity consumption while homes and businesses reduce overall fossil fuel usage and carbon dioxide emissions.

The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) are providing funding for the expansion of clean industry and rebuilding of infrastructure in the United States, often with more electrical intensity to reduce overall carbon emissions.

Data Centers

Energy consumption by data centers in the United States is expected to double by 2030 according to a recent study by the Electric Power Research Institute (EPRI).[15] Trends in computing are shifting towards cloud-based platforms and Artificial Intelligence (AI), driving the expansion of new data centers being built with capacities ranging from 100 MW to over 1,000 MW in locations with interconnection capabilities for large loads. These loads are typically very high load factor facilities requiring high energy density to support their operation.

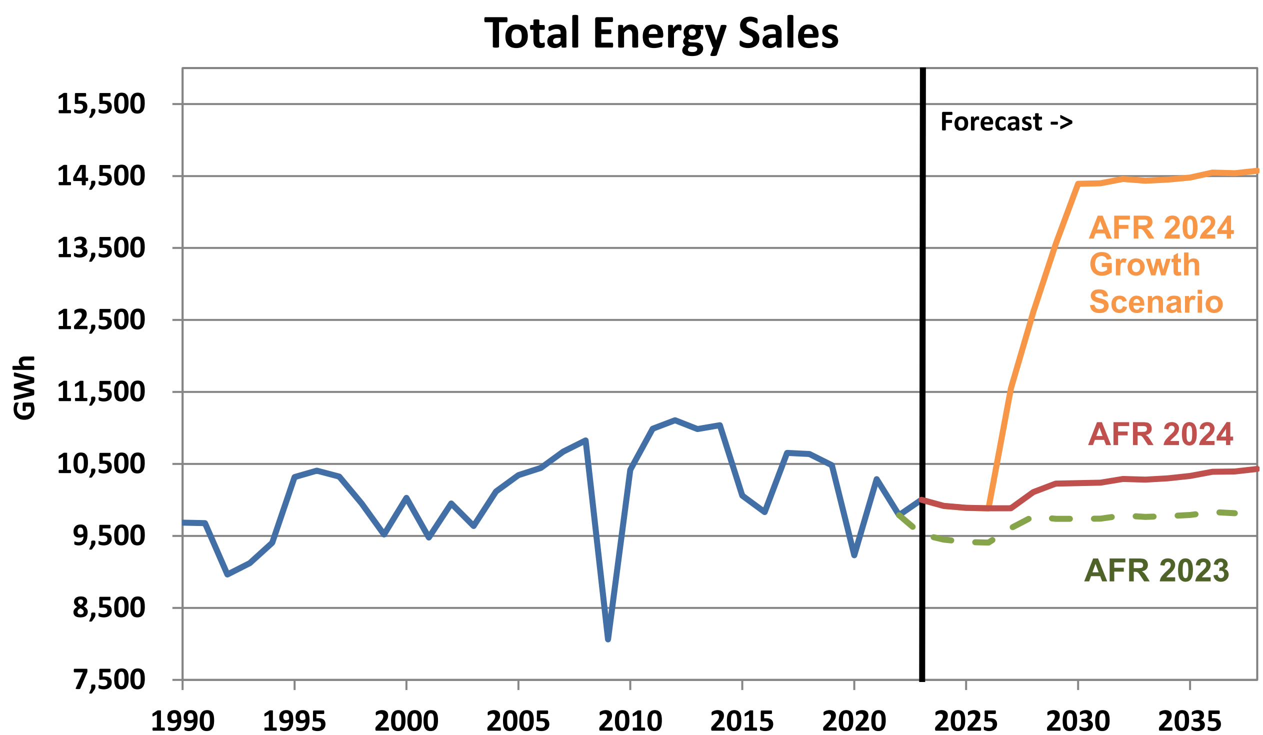
Green Steel

Steel manufacturing is transitioning to less carbon intensive methods which increase the utilization of electricity for advanced processing of minerals and ultimate manufacturing of cleaner steels. Government financial incentives and customer demand is also driving the pursuit of manufacturing of completely “green steel” which is free from the use of fossil fuels in their production. Green steel methods are electric and hydrogen intensive, and according to a recent study by the National Renewable Energy Lab (NREL), Minnesota is an ideal location for green steel production[16].

15 https://www.epri.com/research/products/3002028905.

Below, for the Load Growth Forecast Planning scenario, the total energy sales graph displays the base AFR 2024 results, along with the AFR 2024 load growth scenario.

Figure 23 Total Energy Sales for Load Growth Forecast Planning Scenario



16 https://www.energy.gov/communitiesLEAP/articles/nrel-researchers-find-minnesota-promising-state-low-emission-and.

The table below shows the peak forecast results based on the load growth forecast planning scenario included in the AFR 2024 filing.

Figure 24 Peak Forecast (MW) for the Load Growth Forecast Planning Scenario

Peak Forecast (MW)

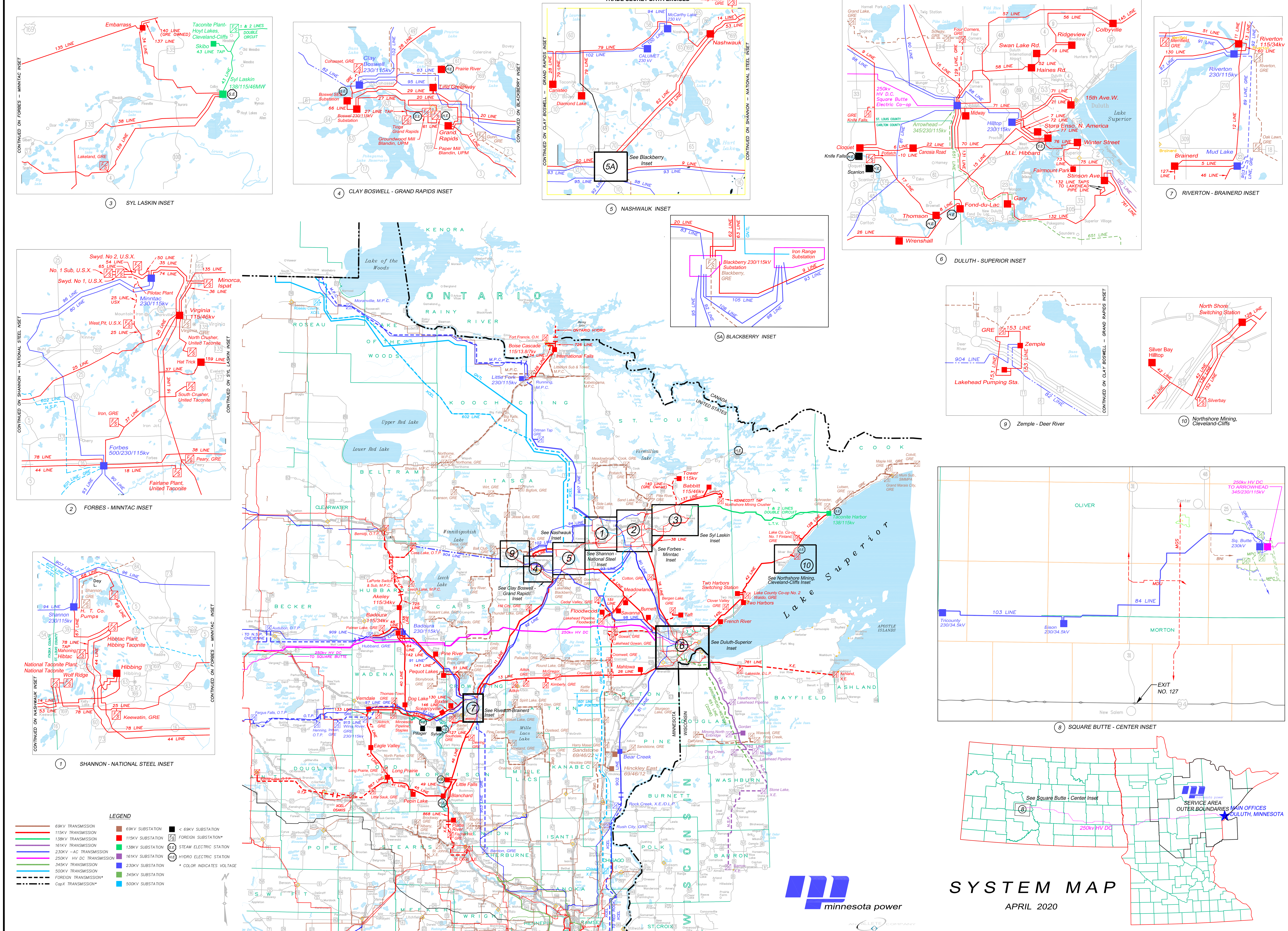
	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak		
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*
2000					1,469	1,503	242	281	1,711	1,784	*1,784*
2001					1,383	1,421	150	175	1,533	1,595	*1,595*
2002					1,464	1,455	165	287	1,629	1,742	*1,742*
2003					1,342	1,496	310	250	1,651	1,746	*1,746*
2004					1,449	1,533	218	250	1,667	1,783	*1,783*
2005					1,535	1,555	255	238	1,789	1,793	*1,793*
2006					1,584	1,534	237	232	1,821	1,766	*1,821*
2007					1,582	1,584	246	241	1,828	1,825	*1,828*
2008					1,529	1,575	228	203	1,757	1,777	*1,777*
2009					1,200	1,369	211	246	1,411	1,615	*1,615*
2010					1,591	1,599	140	190	1,732	1,789	*1,789*
2011					1,573	1,630	173	150	1,746	1,780	*1,780*
2012					1,603	1,605	186	168	1,789	1,773	*1,789*
2013					1,645	1,589	135	162	1,781	1,751	*1,781*
2014					1,620	1,637	184	180	1,805	1,818	*1,818*
2015					1,442	1,461	148	87	1,589	1,547	*1,589*
2016					1,453	1,520	157	173	1,610	1,693	*1,693*
2017					1,538	1,594	150	195	1,688	1,789	*1,789*
2018					1,585	1,557	139	150	1,724	1,707	*1,724*
2019					1,560	1,588	108	99	1,668	1,687	*1,687*
2020					1,410	1,548	78	97	1,487	1,646	*1,646*
2021					1,553	1,556	73	108	1,625	1,663	*1,663*
2022					1,484	1,456	49	94	1,533	1,550	*1,550*
2023					1,551	1,518	63	112	1,614	1,630	*1,630*
2024	1,372	1,376	132	138	**1,504**	**1,514**	112	112	**1,616**	**1,626**	**1,626**
2025	1,371	1,374	132	143	**1,503**	**1,517**	112	112	**1,615**	**1,629**	**1,629**
2026	1,371	1,376	133	339	**1,503**	**1,715**	112	112	**1,615**	**1,827**	**1,827**
2027	1,371	1,375	330	443	**1,701**	**1,818**	112	112	**1,813**	**1,930**	**1,930**
2028	1,370	1,376	462	585	**1,833**	**1,961**	112	112	**1,945**	**2,073**	**2,073**
2029	1,371	1,376	572	686	**1,943**	**2,063**	112	112	**2,055**	**2,175**	**2,175**
2030	1,372	1,377	671	688	**2,043**	**2,065**	112	112	**2,155**	**2,177**	**2,177**
2031	1,372	1,379	670	692	**2,043**	**2,070**	112	112	**2,154**	**2,182**	**2,182**
2032	1,374	1,379	670	696	**2,044**	**2,076**	112	112	**2,156**	**2,187**	**2,187**
2033	1,375	1,379	670	704	**2,045**	**2,083**	112	112	**2,157**	**2,195**	**2,195**
2034	1,375	1,380	670	713	**2,046**	**2,093**	112	112	**2,157**	**2,205**	**2,205**
2035	1,376	1,380	672	724	**2,048**	**2,104**	112	112	**2,160**	**2,216**	**2,216**
2036	1,377	1,381	674	736	**2,050**	**2,117**	112	112	**2,162**	**2,228**	**2,228**
2037	1,377	1,381	676	749	**2,053**	**2,130**	112	112	**2,165**	**2,242**	**2,242**
2038	1,378	1,351	678	748	**2,056**	**2,099**	112	112	**2,168**	**2,211**	**2,211**

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	)ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of August, 2024, she served Minnesota Power's Annual Electric Utility Forecast Report in **Docket No. E-999/PR-24-11** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

____
Tiana Heger

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED



US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 07/31/2026

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

REPORT FOR: ALLETE, Inc. 12647

REPORTING PERIOD: 2023

Contact Theodore Widmer
Title: Account Analyst II

Phone: (218) 355-3197 FAX: Email: twidmer@allete.com

Logged By / Date:
Logged In: Receipt Date (mm/dd/yyyy):

Supervisor Josh Rostollan
Title: Supervisor

Phone: (218) 355-3151 FAX: Email: jrostollan@allete.com

1	Legal Name of Industry Participant	ALLETE, Inc. **Submission Status/Date:** Not Submitted
2	Current Address of Principal Business Office	30 West Superior Street Duluth MN 55802 0000
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator ☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.				
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] FRCC [x] MRO	[ ] NPCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] SERC	[ ] SPP [ ] WECC
2	Name of RTO or ISO	[ ] California ISO [ ] Electric Reliability Council of Texas [ ] PJM Interconnection [ ] New York ISO	[ ] Southwest Power Pool [X] Midwest ISO [ ] ISO New England [ ] None	
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO		
4	Did Your Company Operate Generating Plants(s)?	[x] Yes	[ ] No	
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [x] Transmission [x] Buying transmission services on other electrical system [x] Distribution using owned/leased electric wires	[ ] Buying distribution on other electrical system [x] Wholesale power marketing [ ] Retail power marketing [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))	
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 1,551.0	Prior Year 1,485.0	
		Winter (Megawatts) 1,528.0	Prior Year 1,556.0	
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes	[ ] No	
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes	[ ] No	
	If "Yes", Please Provide Additional Contact Information	Name: Nicholas Powell Title: Supervisor, Fleet Maintenance Telephone: 218 - 355 - 2976	Fax: - -	Email: npowell@mnpower.com

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY		MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation		6,403,860	11	Sales to Ultimate Consumers	8,478,783
2	Purchases from Electricity Suppliers		6,802,288	12	Sales For Resale	4,307,131
3	Exchanged Received (In)			13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)			14	Energy Consumed By Respondent Without Charge	17,067
5	Exchanged Net					
6	Wheeled Received (In)		2,802,089			
7	Wheeled Delivered (Out)		2,716,858	15	Total Energy Losses (positive number)	488,398
8	Wheeled Net		85,231			
9	Transmission by Others Losses (Negative Number)					
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)		13,291,379	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	13,291,379

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	848,266.5
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	253,553.9
4	Electric Credits/Other Adjustments	$	-19,766.5
5	Revenue from Transmission	$	87,933.8
6	Other Electric Operating Revenue	$	27,231.8
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	1,197,219.5

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **MN**

1	Total Number of Distribution Circuits	339.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	1.0

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

		State	MN
3a.	SAIDI value including Major Event days		120.540
3b.	SAIDI value excluding Major Event days		103.600
4	SAIDI value including Major Event days minus loss of supply		108.880
5a.	SAIFI value including Major Event days		1.240
5b.	SAIFI value excluding Major Event days		1.160
6.	SAIFI value including Major Event days minus loss of supply		1.050
7.	Total number of customers used in these calculations		144,144.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		69.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[ ] Yes	[x] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State MN **Balancing Authority**	56669				
Revenue (thousand dollars)	140,937.3	168,223.2	539,106.0	0.0	848,266.5
Megawatthours	1,004,064	1,230,360	6,244,359	0	8,478,783
Number of Customers	125,573	25,703	403	0	151,679
Are your rates decoupled?	Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	14.037	13.673	8.633		10.005
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					

Total					
Revenue (thousand dollars)	140,937.3	168,223.2	539,106.0	0.0	848,266.5
Megawatthours	1,004,064	1,230,360	6,244,359	0	8,478,783
Number of Customers	125,573	25,703	403	0	151,679

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SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total

Revenue (thousand dollars)

Megawatthours

Number of Customers

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2023

SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **MN** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	18,787.176	48,555.021			67,342.197
2	Peak Demand Savings (MW)	2.199	4.272			6.471
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	274255.066	639,718.157			913,973.223
4	Peake Demand Savings (MW)	1.603	2.768			4.371
	Reporting Year Incremental Costs					
5	Customer Incentives	1,949.490	2,618.150			4,567.640
6	All other costs	1,807.620	3,370.310			5,177.930
	Incremental Life Sycle Costs					
7	Customer Incentives	1,949.490	2,618.150			4,567.640
8	All other costs	1,807.620	3,370.310			5,177.930
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	14.598	13.175			28.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

US Department of Energy
Energy Information Administration
Form EIA-861

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **MN** **Balancing Authority** **56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	7,126	490	6		7,622
2	Energy Savings (Mwh)	64.134	58.713	0.530		123.377
3	Potential Peak Demand Savings (MW)	21.219	3.461	303.045		327.725
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
5	Customer Incentives	1,518.658	615.046	10,062.653		12,196.357
6	All other costs					

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **MN** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	4,788				4,788

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **MN** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	51	2	0	0	53
2	Number of AMI Meters	125,522	25,701	403	0	151,626
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	0	0	0	0	0
5	Total Number of Meters (All Types), line 1+2+4	125,573	25,703	403	0	151,679
6	Energy Served Through AMI	1,003,656	1,178,734	6,244,359	0	8,426,749
7	Number of Customers able to access daily energy usage through a webportal or other electronic means	125,573	25,703	403	0	151,679
8	Number of customers with direct load control					

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State **MN** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photo voltaic	Net Metering Installed Capacity (MW)	7.545	6.798	0.020	0.000	14.363
	Net Metering Installations	823	167	1	0	991
	Virtual NM Installed Capacity (1 MW and greater)					0.000
	Virtual NM Customers (1 MW and greater)					0
	Virtual NM Installed Capacity (less than 1MW)	0.518	0.522	0.000	0.000	1.040
	Virtual NM Customers (less than 1MW)	94	3	0	0	97
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	2,103.495	767.732	0.000	0.000	2,871.227
Battery Storage	PV-Paired Net Metering Installed Capacity (MW)	0.299	0.006			0.305
	PV-Paired Energy Capacity (MWh)					0
	PV-Paired Installations	20.000	1.000			21.000
	Non PV-Paired Net Metering Installed Capacity (MW)					0.000
	Non PV-Paired Energy Capacity (MWh)					0
	Non PV-Paired Net Metering Installations					0.000
	Total Battery Storage Capacity	0.299	0.006	0.000	0.000	0.305
	Total Battery Storage Energy Capacity (MWh)	0	0	0	0	0
	Total Battery Storage Installations	20	1	0	0	0
Wind	Installed Net Metering Capacity (MW)	0.082	0.093			0.175
	Number of Net Metering Customers	8	7			15
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	1.038			1.038
Other	Installed Net Metering Capacity (MW)					0.000
	Number of Net Metering Customers					0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0.000

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SCHEDULE 7. PART A. NET METERING Continued

	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Installed Net Metering Capacity (MW)	8.145	7.413	.02	0	15.578
Number of Net Metering Customers	925	177	1	0	1103
If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	2103.495	768.77	0	0	2872.265

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Grand Total All States	**Net Metering Installed Capacity (MW)**	8.145	7.413	.02	0	15.578
	Net Metering Installations/customers	925	177	1	0	1103
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	2103.495	768.77	0	0	2872.265

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REPORT FOR ALLETE, Inc.

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SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	Balancing Authority	< 1MW

1. Number of generators
2. Total combined capacity (MW)
3. Capacity that consists of backup-only units
4. Capacity owned by respondent

Capacity by Technology and Sector (MW)

	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10, Photovoltaic						
11. Storage						
12. Wind turbine(s)						
13. Other						
14. Total						

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Aitkin				
2	MN - Benton				
3	MN - Carlton				
4	MN - Cass				
5	MN - Cook				
6	MN - Crow Wing				
7	MN - Hubbard				
8	MN - Itasca				
9	MN - Koochiching				
10	MN - Lake				
11	MN - Morrison				
12	MN - Otter Tail				
13	MN - Pine				
14	MN - St Louis				
15	MN - Stearns				
16	MN - Todd				
17	MN - Wadena				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part		State	BA ID	Error No.	Error Description/Override Comment	Type	Override
7	A	MN	56669	900	You must answer the AC/DC question for PV solar capacity.	W	

TITLE PAGE

MINNESOTA POWER

ELECTRIC RATE BOOK

This book contains Minnesota Power's retail rates and related information per the Minnesota Department of Public Service Initial Filing Instructions issued November 18, 1974 and is the Company's official Electric Rate Book on file with the Minnesota Department of Commerce.

The Minnesota Power official responsible for this rate book is:

Leah N. Peterson
Manager - Customer Analytics

Authorizing Signature: Leah Peterson

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESIDENTIAL SERVICE

RATE CODES

Residential - General	20
Residential - Space Heating	22
Residential - Seasonal	23

APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations, and any applicable Riders. There is a maximum of one Residential – General or Residential – Space Heating service per customer.

A customer will be billed on the seasonal rate if the dwelling is typically occupied for 182 days or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$9.00	$15.00
All kWh (¢/kWh)	9.403¢	9.624¢

0 kWh to 600 kWh discount for eligible customers -3.761¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

RESIDENTIAL SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh, along with being a low-income customer. A low-income customer is defined as eligible for the Low Income Home Energy Assistance Program ("LIHEAP") in Minnesota Power's billing system or a customer who has completed a self-declaration process. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

11. Eligible customers will receive the discount for a one year time period, at which point average monthly usage will be re-calculated to determine the continued eligibility for the following year.

RESIDENTIAL SERVICE

12. Self-declaration for the low-income eligibility will require a renewal every two years in general and every four years for those on a fixed income.

13. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

14. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)
Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus
Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20 hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)	
Small Service	6.916¢ per kWh
Large Service	6.916¢ per kWh

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

Energy Charge - Dual Fuel Plus	
Small Service	4.703¢ per kWh
Large Service	4.703¢ per kWh

Plus any applicable Adjustments.

Customers who have a qualified Air Source Heat Pump as approved by the company, may elect to be exempt from dual fuel interruptions from June through September and would pay the energy charge below.

Energy Charge	
All kWh (per kWh)	9.403¢

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. Interruption will normally occur at such times:

   (a) when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when the Company expects to incur a new system peak,
   (c) at such other times when, in the Company's opinion, system reliability is endangered,
   (d) when the Company performs necessary testing for certification of interruptibility of customers' loads.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL FIXED OFF-PEAK SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge	
Small Service (per kWh)	4.703¢
Large Service (per kWh)	4.703¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city’s Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer’s bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

RESIDENTIAL FIXED OFF-PEAK SERVICE

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer's load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

To electric service for residential customers for the sole purpose of recharging electric vehicle(s). Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	\$4.25
Off-Peak Energy Charge All kWh (per kWh)	3.145¢
On-Peak Energy Charge All kWh (per kWh)	11.233¢

Plus any applicable Adjustments.

RENEWABLE ENERGY OPTION

Customers taking service under this schedule have the option to purchase energy from the Company’s current mix of energy supply sources at the rates shown above or entirely from renewable energy sources. “Renewable energy” means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary, and Customers who elect this option shall commit to renewable energy for no less than one year. The rate for the renewable energy option will include a 2.5¢ per kWh surcharge in addition to the per kWh energy charges shown above.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city’s Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer’s bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The Residential Off-Peak Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

2. The total connected off-peak load shall not exceed 100 kW.

3. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

5. On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER

Service Charge	$15.00
Energy Charge for all kWh	9.332¢

CUSTOMERS WITH A DEMAND METER

Service Charge	$15.00
Demand Charge for all kW	$8.00
Energy Charge for all kWh	6.507¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

Filing Date November 1, 2023 **MPUC Docket No.** E015/GR-23-155
Effective Date January 1, 2024 **Order Date** December 19, 2023

Approved by: Leah N. Peterson
Leah N. Peterson
Manager – Customer Analytics

GENERAL SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

GENERAL SERVICE

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city’s Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer’s bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2,500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

Commercial and Industrial EV Service	29
Company- owned Electric Vehicle Service Equipment	31

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

Also available to Company-Electric Vehicle Service Equipment

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge for On-Peak kW	$8.00
Energy Charge for all kWh	6.507¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. CST, Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. CST, Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)

Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus

Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20-hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE (Monthly)

Service Charge

Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)

Small Service	6.916¢ per kWh
Large Service-Low Voltage	6.916¢ per kWh
Large Service-High Voltage	6.770¢ per kWh

Energy Charge – Dual Fuel Plus

Small Service	4.703¢ per kWh
Large Service-Low Voltage	4.703¢ per kWh
Large Service-High Voltage	4.601¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when the Company expects to incur a system peak,

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(c) when, in the Company's opinion, the reliability of the system is endangered, or
(d) when the Company performs necessary testing of interruptibility of customer's loads.

Interruptions shall normally occur for reliability-related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

7. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, as specified in Dual Fuel program options above.

8. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

   (a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).
   (b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer's service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time (CPT) each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge

Small Service	$6.00
Large Service	$16.00

Energy Charge

Small Service - Low Voltage	4.703¢ per kWh
Large Service - Low Voltage	4.703¢ per kWh
Large Service - High Voltage	4.710¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer’s load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company’s control point for operation of Company’s control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,050.00
All additional kW of Billing Demand ($/kW)	$9.50
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$4.00
Energy Charge	
All kWh (¢/kWh)	4.574¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will be subject to a discount of 0.800¢ per kWh of Energy. Where service is delivered and metered

LARGE LIGHT AND POWER SERVICE

at (or compensated to) the available distribution bulk delivery voltage of 23,000 to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

LARGE LIGHT AND POWER SERVICE

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the lower of:

a) 75% of the greatest adjusted demand during the preceding eleven months, or
b) The greatest adjusted demand during the preceding eleven months minus 100 kW.

However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

RATE CODES

73

APPLICATION

To the electric service requirements of a customer requiring service for no less than 2,000 kW and no more than 50,000 kW of connected load, where such electric service requirements are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at the voltage level specified in customer's contract.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

3. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Light and Power Service Rate Schedules 75 and the cost to the customer of the lowest cost competitive energy supply.

4. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

5. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Light and Power Service Rate Schedules 75 and the competitive rate times the usage level during the test year period.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

6. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

7. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

8. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

9. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

LARGE POWER SERVICE

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company (“Confidential Information”), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term “Holidays” shall mean New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year’s Eve Day.

For purposes of ESAs, the term “Office” shall mean the Minnesota Office of Energy Security or its successor organization.

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company’s available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

LARGE POWER SERVICE

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$229,330
All additional kW of Firm Demand ($/kW)	$22.25

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$5.49

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.087¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under "ENERGY."

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Interim Rate Adjustment. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

3. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Charge.

4. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

5. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

LARGE POWER SERVICE

6. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

7. CARE Low-Income Affordability Program Surcharge. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

8. Solar Energy Adjustment. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

9. Minnesota Policy Adjustment. The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

10. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

11. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

LARGE POWER SERVICE

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be based on amount specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this a mount shall be deemed to be the Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases. For all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or

LARGE POWER SERVICE

participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion
For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company’s estimated annual Revenue Requirements per kW associated with Company’s power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

LARGE POWER SERVICE

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion
For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$275,196
All additional kW of Non-Contract Billing Demand ($/kW)	$26.70

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$6.35

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.087¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY."

Plus any applicable Adjustments.

NON-CONTRACT LARGE POWER SERVICE

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge. Such Fuel Charge shall be applicable to Customer's Non-Contract Firm Energy only.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

6. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Minnesota Policy Adjustment: The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

NON-CONTRACT LARGE POWER SERVICE

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

NON-CONTRACT LARGE POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

<u>Capacity Portion</u>
For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

<u>Energy Portion</u>
For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

NON-CONTRACT LARGE POWER SERVICE

Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

RATE CODES

79

APPLICATION

To the electric service requirements of a customer requiring 10,000 kW or more, where the electric service requirements of 10,000 kW or more are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Three phase, 60 hertz at high voltage of 13,000 through 69,000 volts or at transmission voltage of 115,000 volts.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

3. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Power Service Rate Schedules 74 and the cost to the customer of the lowest cost competitive energy supply.

4. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

5. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Power Service Rate Schedules 74 and the competitive rate times the usage level during the test year period.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

6. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

7. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

8. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

9. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Lamp Type & Size		CIS Code	Rate Per Lamp Per Month Option 1	Option 2 (Option 2 Closed to New Installation)	Option 3 (Option 3 Closed to New Installation)	Option 4
Mercury Vapor Lamps (Closed to New Installation)						
7,000	Lumens (175 watts)	MV175W	$12.92	$9.03		
20,000	Lumens (400 watts)	MV400W	$20.57	$13.62		
55,000	Lumens (1,000 watts)	MV1000W	$38.33	$27.00		
Sodium Vapor Lamps						
8,500	Lumens (100 watts)	SV100W	$11.34	$6.54	$6.54	
14,000	Lumens (150 watts)	SV150W	$13.07	$8.34		
23,000	Lumens (250 watts)	SV250W2	$18.54	$11.11	$11.19	
45,000	Lumens (400 watts)	SV400W	$24.83	$16.35	$11.87	
Metal Halide Lamps						
17,000	Lumens (250 watts)	MH250W	$18.34			
28,800	Lumens (400 watts)	MH400W	$22.34		$13.24	
88,000	Lumens (1,000 watts)	MH1000W	$37.22		$24.18	
Light Emitting Diodes (LED)						
4,000	Lumens (48 watts or less)	LED48W	$9.89	$9.89		
10,000	Lumens (71 watts or less)	LED71W	$13.21			
24,000	Lumens (184 watts or less)	LED184W	$19.96			
46,800	Lumens (320 watts or less)	LED320W	$28.71			

OUTDOOR AND AREA LIGHTING SERVICE

Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$11.54	$11.54	$11.54	
Monthly Service Charge		Included	Included	Included	$3.67
Energy Charge - Per kWh		Included	Included	Included	6.583¢

Plus any applicable adjustments

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

OUTDOOR AND AREA LIGHTING SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
	Daily Estimates	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours		4200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH250W	3	1,260	139	114	110	91	79	70	76	88	101	120	130	142
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MH1000W	12	4,410	485	398	385	317	277	245	264	309	353	421	457	499
LED48W	1	207	23	19	18	15	13	11	12	14	17	20	21	24
LED71W	1	299	33	27	26	21	19	17	18	21	24	28	31	34
LED184W	2	774	85	70	68	56	49	43	46	54	62	74	80	87
LED320W	4	1,344	148	121	117	97	84	75	81	94	108	128	139	152

Company shall furnish all electric energy required for service under this schedule.

OUTDOOR AND AREA LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, photo-electric control and wiring.

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include, but not be limited to, the fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option, including poles, except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

OUTDOOR AND AREA LIGHTING SERVICE

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include, but not be limited to, the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, over and above those which would be required for a single standard bracket mounting, shall not exceed $15.00 per light. Additional required investment will be at Customer's expense.

OUTDOOR AND AREA LIGHTING SERVICE

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. The Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Materials charges per the Company's cost for lighting replacement equipment plus the then current Material Handling Expense and A&G expense per Company's Accounting Manual.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Lamp Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Option 2 Closed to New Installation)	Option 3 (Option 3 Closed to New Installation)	Option 4
Mercury Vapor Lamps (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$17.85	$10.65	$8.89	
10,000 Lumens (250 watts)	MV250W			$11.30	
20,000 Lumens (400 watts)	MV400W	$24.28	$16.47	$15.27	
55,000 Lumens (1,000 watts)	MV1000W2			$27.46	
Sodium Vapor Lamps (Closed to New Installations)					
8,500 Lumens (100 watts)	SV100W	$15.77	$8.36	$7.14	
14,000 Lumens (150 watts)	SV150W	$17.45	$9.79	$10.05	
14,000 Lumens (150 watts)	SV150W-P			$9.11	
20,500 Lumens (200 watts)	SV200W	$21.58	$13.24	$10.98	
23,000 Lumens (250 watts)	SV250W	$21.73	$13.95	$11.86	
45,000 Lumens (400 watts)	SV400W	$26.69	$19.75	$14.28	
Metal Halide Lamps (Closed to New Installations)					
28,800 Lumens (400 watts)	MH400W		$17.46		

STREET AND HIGHWAY LIGHTING SERVICE

Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$14.95			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$19.89			
23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$24.73			
Monthly Service Charge		Included	Included	Included	$3.67
Energy Charge - Per kWh		Included	Included	Included	6.583¢
Plus any applicable adjustments					

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 13.82% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. The monthly fuel and purchased energy adjustment per fixture shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

STREET AND HIGHWAY LIGHTING SERVICE

9. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	Daily Estimates	4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W2	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV150W-P	1	468	51	42	41	34	29	26	28	33	37	45	48	54
SV200W	3	1,140	125	103	100	82	72	63	68	80	91	109	118	129
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

Company shall furnish all electric energy required for service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, fixture, ballast, photo-electric control, driver, and wiring.

Option 2

The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's facilities. The equipment shall include, but not be limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications. In all cases, poles are owned by Company.

The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls. Option 2 is closed to new installations.

Option 3

The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, lamp, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

STREET AND HIGHWAY LIGHTING SERVICE

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out lamps and photo-electric controls and will clean or replace glassware at the time of lamp replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of fixtures of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For fixtures which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

7. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73. and 79.

FUEL AND PURCHASED ENERGY CHARGE

The Forecasted System Average Fuel and Purchased Energy (FPE) Charge for each month shall be the forecasted FPE Charge for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted FPE Charge shall be added to customers' monthly bill according to each customer's rate class and Fuel and Purchased Energy Adjustment (FPEA) Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve month recovery period the true-up rate will be in effect and then multiplied by the applicable FPEA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly FPE Charge.

FORECASTED SYSTEM AVERAGE FUEL AND PURCHASED ENERGY CHARGE

The monthly Forecasted Average Fuel and Purchased Energy Charge shall be the **sum** of the following:

(a) The fossil and nuclear fuel forecasted to be consumed in Company's generating stations,

(b) The forecasted net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is to be purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

(c) The forecasted identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,

(d) The forecasted cost of steam from other sources to be used in the generation of electricity at the Company's generating stations,

(e) The forecasted cost of the Released Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

(f) The forecasted cost of the Buyback Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

(g) Forecasted fuel and purchased energy expenses to be incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691 excluding the cost of fuel and purchased energy related to meeting the Solar Energy Standard,

(h) All forecasted RTO (Regional Transmission Organization) energy market costs net of revenues, excluding administrative costs,

(i) The forecasted cost of the purchase of SO_2 allowances,

(j) The forecasted Time of Generation Adjustment as calculated in the Rider for Solar Energy Adjustment

and **less**

(k) Forecasted revenues from the sale of SO_2 allowances,

(l) The forecasted cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis,

(m) Forecasted net revenues from the sale of environmental attributes from any Commission approved contract, and

(n) Forecasted net revenues (margins) from asset-based wholesale energy and capacity sales.

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (l) above and solar energy production and purchases referred to in (g) above.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

FUEL AND PURCHASED ENERGY ADJUSTMENT (FPEA) FACTORS

A separate FPEA Factor shall be applied to calculate the Forecasted FPE Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) customers a TOD Factor shall also be calculated for each TOD period. The FPEA Factor is the Class Cost Factor multiplied by the corresponding TOD Factor.

Rate Class	Class Cost Factor	TOD Factor	FPEA Factor
Residential	1.01868	1.00000	1.01868
Residential On-Peak	1.01868	1.17042	1.19228
Residential Off-Peak	1.01868	1.03330	1.05260
Residential Super Off-Peak	1.01868	0.75930	0.77348
General Service	1.03138	1.00000	1.03138
Large Light & Power	1.00656	1.00000	1.00656
Large Power	0.99026	1.00000	0.99026
Lighting	0.85420	1.00000	0.85420

2024 FORECASTED and 2022 TRUE-UP FPE RATE

The monthly forecasted 2024 FPE Rate was approved by the Minnesota Public Utilities Commission ("Commission") Order issued on November 9, 2023, in Docket No. E015/AA-23-180.

The 2022 FPE True-up Rate was approved in the Commission Order issued on July 31, 2023, in Docket No. E015/AA-21-312.

Applicable Month	FPE 2024 Forecasted Rate (¢/kWh)	FPE 2022 True-up Rate (¢/kWh)
January	3.521	0.167
February	3.421	0.183
March	2.937	0.175
April	2.884	0.193
May	3.096	0.190
June	2.740	0.195
July	3.173	0.182
August	3.229	0.184
September	2.961	
October	2.874	
November	2.830	
December	3.159	

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

A breakdown by month and Rate Class can be found on Minnesota Power's website at https://www.mnpower.com/CustomerService/YourBill

TEMPORARY SERVICE RIDER TO GENERAL SERVICE SCHEDULES

Any customer whose use of service may be temporary (less than one year duration) shall receive service under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Customer will pay in advance the estimated cost of installation and removal, less salvage, of facilities required to render service. Where the actual cost of providing such facilities is different from the advance payment, as determined upon completion of temporary service, Company will refund any excess payment made by Customer or render a bill for any additional costs.

2. Customer may at any time terminate service under this Rider and contract to receive future service under any applicable Schedule.

3. If Customer requests that service be discontinued and subsequently requests restoration of service at the same premises within 12 months of discontinuance, the charge for restoring service will be the sum of the minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service. The minimum bills during the elapsed period shall also include any billings which would have been applicable as a result of the minimum under the below Modification.

MODIFICATION

The second paragraph under DETERMINATION OF THE BILLING DEMAND in the applicable General Service rate schedule shall be changed to read as follows:

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the greatest adjusted demand during the preceding eleven months, nor less than the minimum demand specified in customer's contract.

SPORTS FIELD LIGHTING RIDER TO GENERAL SERVICE SCHEDULES

Any customer may elect to receive service for sports field lighting under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Service is available hereunder only to the extent that Company has unused capacity in facilities at the location. Customer shall pay any cost of extending or increasing the capacity of facilities.

2. Customer will own, install and maintain any transformers or other facilities required to utilize the available line voltage.

MODIFICATIONS

1. Service will be at the available line voltage (and phase).

2. The HIGH VOLTAGE SERVICE provision will not be applicable.

3. Demand will not be measured.

RIDER FOR MULTIPLE METER SERVICE

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through more than one meter, and such services were being received on April 1, 1977. It is anticipated that after April 1, 1977, there may be conditions under which it will be desirable and/or necessary to provide service to customers at more than one point of delivery (Multiple Meter Service). Therefore at Company's discretion, a customer not receiving multiple meter service on April 1, 1977, or receiving multiple meter service but desiring an additional point of delivery may receive such service upon completion and proper approval of "Request for Multiple Meter Service".

CONDITIONS

1. When service is being taken through more than one meter, the metered quantities of demand (kW) and energy (kWh) at each metered point of service shall be billed under a separate application of a standard rate schedule.

2. The conditions under which a "Request for Multiple Meter Service" may be approved include but are not limited to:

   a. Customer's premises are divided by a public road or alley preventing the customer from performing its own distribution of service.

   b. Customer's buildings or operations are geographically separated to the extent that it is not electrically feasible for the customer to perform its own distribution of service.

   c. The location and/or adequacy of existing Company facilities make it economically more advantageous for Company to provide an additional point of delivery.

   d. Customers having two or more separate businesses on one premises for which the electric service costs must be accounted for separately.

RIDER FOR EXPEDITED BILLING PROCEDURES

APPLICATION

Applicable to taconite producing customers taking Large Power Service under Schedule 74 under Non-Contract Large Power Service Schedule 78, and under any other Large Power rate schedules in effect from time to time.

Service received under Large Light and Power Schedule 75 by a taconite producing Large Power customer may also be billed in accordance with this Rider, at the option of Minnesota Power.

Non-taconite customers taking service under a Large Power Service rate schedule may, at their option, be billed in accordance with the terms of this Rider.

The monthly billing requirement of Minnesota Rule 7820.3300 is modified to permit expedited weekly billing of a customer's electric service in accordance with the terms of this Rider.

TERMS

1. After instituting weekly billing, the bill payment is due in "same day funds" seven (7) days following issuance of the bill, the "Due Date" for payment. "Same day funds" means funds that are available for the Company's use on the same day as the Due Date. Bills not paid in "same day funds" on or before such Due Date as printed on the bill are "past due", or "delinquent." The weekly billing is based on estimated weekly electric service usage, including the minimum demand charge, not on an actual meter reading. Weekly billing payments received and charges for actual electric service usage will be reconciled each month ("actual billing true-up"). The monthly actual billing true-up shall be reflected on the first weekly billing rendered after such true-up amount has been determined. See Exhibit 1 to this Rider.

2. Customers subject to this Rider will receive credit for expedited billing payments reflecting the time value of funds made available to Minnesota Power earlier than such funds otherwise would have been available under the Company's standard monthly billing cycle. When the customer makes its first payment under the expedited cycle, the time value of money associated with that payment will be determined from the due date of that payment to the customer's due date under the standard monthly billing cycle, using prime plus two and one-half percent (2.5%) as the interest rate.

RIDER FOR EXPEDITED BILLING PROCEDURES

This time value of money credit ("TVMC") will be determined for each of the succeeding expedited payments. If the customer has not made timely payment of the estimated bills in full in "same day funds" as they become due on the expedited due dates, no time value of money associated with such late payment will be included in the TVMC. The total TVMC determined in a month shall be given by Minnesota Power to the customer as a credit on the weekly bill that falls on the same week as the due date under the standard monthly billing cycle. If the credit exceeds $100,000, the customer has the option to have Minnesota Power wire the credit to the customer's bank account. The mechanics of this credit are shown on Exhibit 1 of this Rider. The prime rate is defined as the average of the daily prime lending rates offered to preferred customers at the largest bank in the Ninth Federal Reserve District in effect during the month preceding the bill.

Exhibit 1
Page 1 of 3

MINNESOTA POWER
Sample Weekly Billing Procedure
Assuming Procedure Commences January 1

Jan	Tue	1	
	Wed	2	
	Thu	3	
	Fri	4	Bill #1 Issued = 4/31 x Estimated Monthly Billing (EMB) for January
	Fri	11	Bill #2 Issued = 7/31 x EMB for January Bill #1 Due
	Fri	18	Bill #3 Issued = 7/31 x EMB for January Bill #2 Due
	Fri	25	Bill #4 Issued = 7/31 x EMB for January Bill #3 Due
Jan	Thu	31	Meter Read
Feb	Fri	1	Bill #5 Issued = 6/31 x EMB for January + 1/28 x EMB for February Bill #4 Due
	Mon	4	Charges for actual January usage determined January TVMC calculated to February 19th
	Fri	8	Bill #6 Issued = 7/28 x EMB for February Bill #5 Due January Actual Billing True-Up amount determined
	Fri	15	Bill #7 Issued = 7/28 x EMB for February + Actual Billing True-Up amount for January Bill #6 Due
	Tue	19	January TVMC is applied to bill or wire transferred
	Fri	22	Bill #8 Issued = 7/28 x EMB for February Bill #7 Due
Feb	Thu	28	Meter Read
Mar	Fri	1	Bill #9 Issued = 6/28 x EMB for February + 1/31 x EMB for March Bill #8 Due
	Mon	4	Charges for actual February usage determined February TVMC calculated to March 19th
	Fri	8	Bill #10 Issued = 7/31 x EMB for March Bill #9 Due February Actual Billing True-Up amount determined
	Fri	15	Bill #11 Issued = 7/31 x EMB for March + Actual Billing True-Up amount for February Bill #10 Due
	Tue	19	February TVMC is applied to bill or wire transferred

Exhibit 1
Page 2 of 3

MINNESOTA POWER
Sample Monthly Adjustments

January Time Value of Money Credit (TVMC from page 1) assuming Bill #'s 1 thru 5 are paid in full and when due:

January TVMC =
Bill #1 x [(# days from Jan 11 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #2 x [(# days from Jan 18 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #3 x [(# days from Jan 25 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #4 x [(# days from Feb 1 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Jan portion of Bill #5 x [(# days from Feb 8 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%)

January Actual Billing True-Up Adjustment =
Sum of Payments for January service received on or before Feb 19 - Actual Charges for January usage

February Time Value of Money Credit (TVMC from page 1) assuming only Bill #'s 5 and 6 are paid in full and when due:

February TVMC =
Feb portion of Bill #5 x [(# days from Feb 8 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%) +

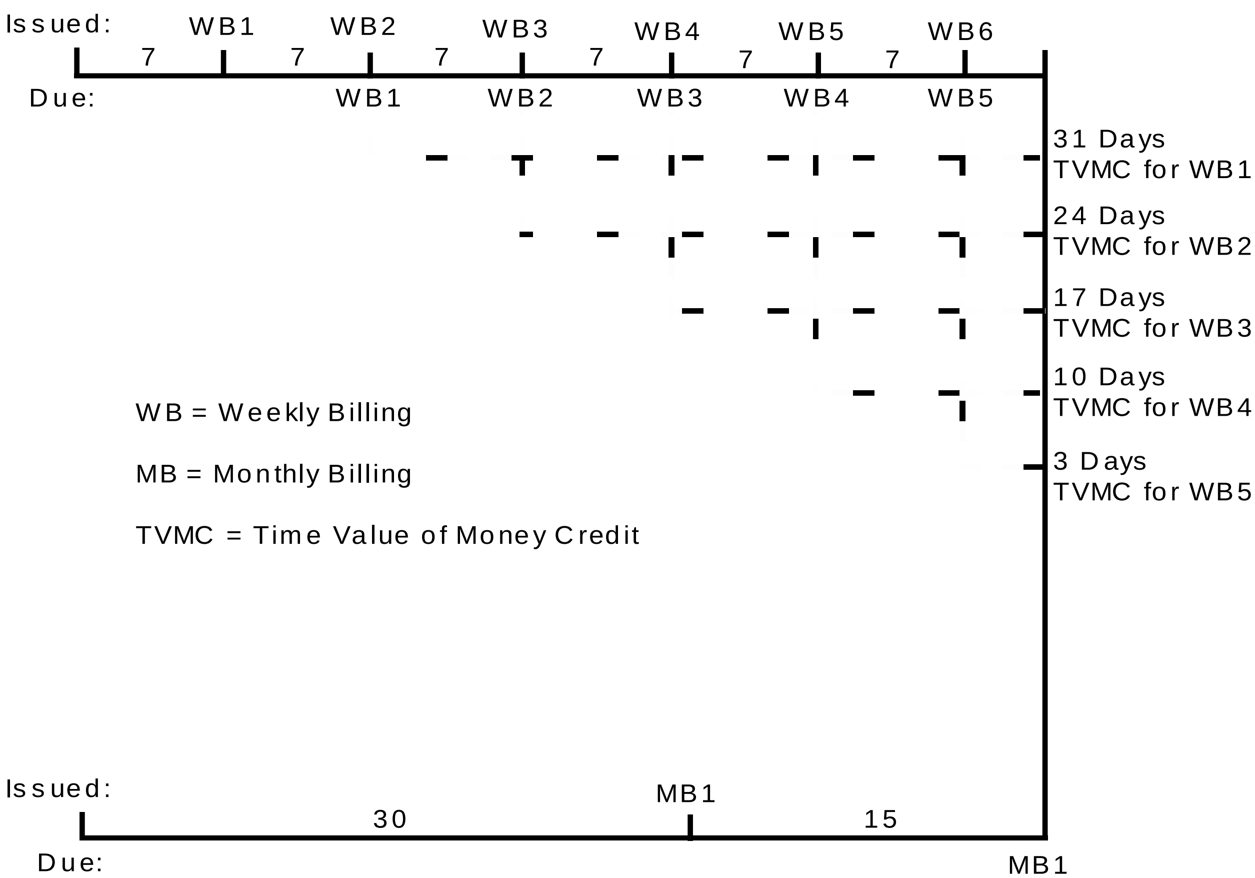
Bill #6 x [(# days from Feb 15 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%)

February Actual Billing True-Up Adjustment =
Sum of Payments for February service received on or before Mar 19 - Actual Charges for February usage

Note:
1) Time Value of Money Credit will not be reflected for any Weekly Billing which has not been received in same day funds, in full and on or before the Due Date.
2) The TVMC is calculated to (and applied to bill or wire transferred on) the standard monthly billing cycle due date which is 15 days from the date customer is notified of the charges for actual monthly usage.

Exhibit 1
Page 3 of 3

MINNESOTA POWER
METHOD FOR DETERMINING
TIME VALUE OF MONEY CREDIT



Note: This example assumes a 30 day month and the due date under the standard monthly billing cycle to be the 15th of the following month.

RIDER FOR SCHOOLS

APPLICATION

To Large Light and Power Service Schedule 75 for schools which are part of the elementary and secondary school system.

MODIFICATIONS

The RATE (Monthly) and other provisions of the applicable schedule shall apply except that:

1. The first block under Demand Charge shall be changed to read, "$10.50 per kW for the first 100 kW of Demand" or less as determined below.

2. Determination of the Billing Demand shall be replaced by the following:

   "Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month as adjusted for power factor, but not less than the minimum demand specified in customer's contract and in no case will the billing demand be less than 50 kW. For all Billing Demand between 51 kW and 100 kW the demand will be billed at the $10.50 per kW rate. All Billing Demand above 100 kW shall be billed at the third block demand rate of $9.50 per kW.

   Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%."

RIDER FOR REVENUE CREDIT FROM NON-CONTRACT LARGE POWER SERVICE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Non-Contract Large Power Service Schedule 78.

REVENUE CREDIT

There shall be deducted from each Customer's monthly bill, as computed under the applicable rate schedule, a Revenue Credit. Such Revenue Credit for each Customer, other than Large Power Service Schedule 74 Customers, shall be a monthly Revenue Credit Rate (¢/kWh) multiplied by the kWh billed in the current month. Such Revenue Credit for Large Power Service Schedule 74 Customers shall be a monthly Revenue Credit Rate ($/kW) multiplied by the Firm Power Billing Demand (kW) billed.

DETERMINATION OF REVENUE CREDIT AMOUNT

The Revenue Credit Amount in month shall be one-sixth (1/6) of the total of all Non-Contract Large Power Service Demand Charges billed in the second preceding month.

REVENUE CREDIT RATES

(a) Applicable to Non-Large Power Service (in ¢/kWh)

The Revenue Credit Amount in month multiplied by .3606; divided by Company's total kilowatt-hour Sales of Electricity, excluding Non-Contract Large Power Service, non-firm service, Resale Service and Large Power Service sales, in the second preceding month.

(b) Applicable to Large Power Service (in $/kW)

The Revenue Credit Amount in month multiplied by .5207; divided by the sum of all Firm Power Billing Demand (kW) billed to Customers under Company's Large Power Service Schedule 74 in the current month.

RIDER FOR CITY OF DULUTH FRANCHISE FEE

APPLICATION

Applicable to bills for electric service within the corporate limits of the City of Duluth, except bills for service to the City of Duluth.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Duluth Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Duluth, which is currently 3% of the total bill excluding sales taxes and is billed per electric service agreement. The fee is listed on the bill as "Duluth Franchise Fee (3%)" and is effective as January 1, 2017.

The total amount assessed to any Minnesota Power customer shall not exceed $420,000 per year.

100% of the City of Duluth Franchise Fee assessment collected will be passed along to the City of Duluth.

RIDER FOR PARALLEL GENERATION

APPLICATION

Applicable to cogenerator or small power producers less than 1,000 kW AC capacity. To any customer taking single or three phase service under one of the Company's standard electric rate schedules and who has entered into a contract with the Company for the sale of electricity as a cogenerator or small power producer (Seller) as defined under State or Federal Law.

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Sellers with Distributed Energy Resources less than 40 kW AC capacity shall have the option of selling to Company under either the Average Retail Energy Rate, the Simultaneous Purchase and Sale Rate or the Time-of-Day Purchase Rate. The Rate selected shall be as specified in the Cogeneration and/or Small Power Production Facilities Agreement between Seller and Minnesota Power.

A. Average Retail Energy Rate
The Seller shall be billed according to the Company's applicable standard rate schedule for the energy (kWh) supplied by the Company that exceeds the amount of energy supplied by the Seller to the Company's distribution system during each billing period. The Seller will be subject to the following Meter Aggregation Charge. When energy supplied by the Seller exceeds the amount of energy supplied by the Company, the Seller shall be subject to the following Average Retail Energy Rate Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Average Retail Energy Rate Credit
12.20¢ per kWh of Net Energy - Residential Customers
13.48¢ per kWh of Net Energy - General Service Customers
10.44¢ per kWh of Net Energy - Large Light & Power Customers

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.71¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
3.71¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.60¢ per kWh delivered to Company during On-Peak periods.
2.80¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
4.70¢ per kWh delivered to Company during On-Peak periods.
2.80¢ per kWh delivered to Company during Off-Peak periods.

II. Distributed Energy Resources at 40 kW AC capacity or greater and less than 500 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate. Customers who do not elect to be compensated for net input in the form of a kilowatt-hour credit under the Kilowatt-Hour Energy Credit rate will be compensated for the net input at the Company's Simultaneous Purchase and Sale Rate or Time-of-Day Purchase Rate.

A. Kilowatt-Hour Energy Credit Rate
The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any

remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.71¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
3.71¢ per kWh delivered to Company

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.71¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
3.71¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and Energy and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.60¢ per kWh delivered to Company during On-Peak periods.

2.80¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
4.70¢ per kWh delivered to Company during On-Peak periods.
2.80¢ per kWh delivered to Company during Off-Peak periods.

III. Distributed Energy Resources at 500 kW AC capacity or greater and less than 1,000 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate.

A. Kilowatt-Hour Energy Credit Rate
The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.71¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
3.71¢ per kWh delivered to Company.

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.71¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
3.71¢ per kWh delivered to Company.

RIDER FOR PARALLEL GENERATION

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and appliable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.60¢ per kWh delivered to Company during On-Peak periods.
2.80¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
4.70¢ per kWh delivered to Company during On-Peak periods.
2.80¢ per kWh delivered to Company during Off-Peak periods.

DETERMINATION OF FIRM POWER

Energy delivered by the QF to the Company must have a 65 percent on-peak capacity factor in the month to be considered "firm power". The capacity factor is based upon the QF's maximum on-peak metered capacity delivered to the Company during the month. If the QF does not meet the firm power requirements, compensation will be for the energy portion only.

INDIVIDUAL SYSTEM CAPACITY LIMITS

1) Customers with a facility of 40-kilowatt AC capacity or more and participating in net metering and net billing may be required to limit the total generation capacity of an individual Distributed Energy Resource by either:
   a. for wind generation systems, limiting the total generation system capacity kilowatt alternating current to 120 percent of the customer's on-site maximum electric demand; or
   b. for solar photovoltaic and other distributed generation, limiting the total generation system annual energy production kilowatt hours alternating current to 120 percent of the customer's on-site annual electric energy consumption.
2) Limits under paragraph (a) applicable to measuring on-site maximum electric demand must be based on standard 15-minute intervals, measured during the previous 12

calendar months, or on a reasonable estimate of the average monthly maximum demand or average annual consumption if the customer has either:
   a. less than 12 calendar months of actual electric usage; or
   b. no demand metering available.

3) The total generation capacity of an individual Distributed Energy Resource is determined by the total capacity of all of the customer's systems which are on the same set of aggregated meters. On-site maximum electric demand and on-site annual electric energy consumption are determined by total demand or electric energy consumption associated with the same set of aggregated meters.
4) For wind generation systems, the Company will estimate customer demand use for purposes of calculating the 120 percent rule by determining a demand-billed customer's highest billed on-site kW demand in all bills issued during the most recent calendar year. For non-demand customers, the Company shall impute the equivalent peak demand level by first determining the customer's most recent on-site annual (12-month) billed kWh sales. Those kWh sales shall be divided by the product of the annual load factor for the applicable customer class and the number of actual hours in that year (either 8,760 hours in a standard year or 8,784 hours in a leap year). The resulting quotient will serve as the customer's estimated on site maximum electric demand. The load factor is 19.3 percent for the residential customer class and 24.2 percent for the non-demand general service customer class as calculated in the Company's 2013 Load Research study.
5) For solar photovoltaic and other Distributed Energy Resources, where 12 months of usage data is not available, the Company will estimate customer energy use for purposes of calculating the 120 percent rule by averaging four months of usage. If four months of usage is not available, the Company will estimate usage based on home size for residential customers and other substantiating documentation for commercial and demand billed customers.

METER AGGREGATION

The Company will aggregate for billing purposes a Customer's designated distributed generation bidirectional meter with one or more aggregated retail meters if a Customer requests that it do so and the following conditions are satisfied:

1) the meters must be located on contiguous property owned by the customer requesting the aggregation;
2) the account(s) associated with the meters must be in the name of the customer;
3) the retail services associate with the aggregated meters of a customer must be either all time-of-day or all non-time-of-day;
4) the total of all aggregated meters must be subject in the aggregate to the size limitation under the single rate chosen by the Customer applicable to all of the aggregated meters; and
5) the total of all aggregated meters is subject in the aggregate to the Individual System Capacity Limits.

RIDER FOR PARALLEL GENERATION

As the term is used here, “contiguous property” means property owned or leased by the Customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or Company rights-of-way. The Company must comply with a request by a customer-generator to aggregate additional meters within 90 days. The specific meters must be identified at the time of the request. In the event that more than one meter is identified, the Customer must designate the rank order for the aggregated meters to which the net metered credits are to be applied. At least 60 days prior to the beginning of the next annual billing period, a Customer may amend the rank order of the aggregated meters.

The aggregation of meters applies only to charges that use kilowatt-hours as the billing determinant. All other charges applicable to each meter account shall be billed to the customer. The Company will first apply the kilowatt-hour credit to the charges for the designated meter and then to the charges for the aggregated meters in the rank order specified by the customer. If the Net Metered Facility supplies more electricity to the Company than the energy usage recorded by the customer-generator's designated and aggregated meters during a monthly billing period, the Company will apply, at the election of the Customer, any excess production based on a monthly credit or the Annual Net Metering (kWh) Banking Option. Where a monthly credit is selected, the Company shall apply monetary credits to the customer's next monthly bill for the excess kilowatt-hours.

DISTRIBUTED ENERGY RESOURCES OF 1,000 KILOWATT CAPACITY OR MORE

A Seller with 1,000 kW AC capacity or more must negotiate a contract with the Company to set the applicable rates for payments to the customer of avoided capacity and energy costs. Sellers fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10,000 kW AC capacity of interconnected capacity at a point of common coupling to Company’s distribution system may also apply for service under the Company’s Rider for Distributed Generation Service.

DEFINITIONS

"Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available before each filing required by parts 7835.0300 to 7835.1200 must be used in the computation.

“Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and a utility's electric system.

RIDER FOR PARALLEL GENERATION

"Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum on-peak metered capacity delivered to the utility during the month.

"Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical Distributed Energy Resources necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated from its own Distributed Energy Resources or purchased from other sources an equivalent amount of electric energy or capacity. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

"Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

“Off-Peak periods” shall include all hours not included in On-Peak periods.

“On-Peak periods” shall include all hours between 7 a.m. and 10 p.m. Monday through Friday excluding holidays.

"Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions.

"Standby charge" means the rate or fee a utility charges for the recovery of costs for the provision of standby service or standby power.

"Standby service" means:
A. for public utilities, service or power that includes backup or maintenance services, as described in the public utility's commission-approved standby tariff, necessary to make electricity service available to the distributed generation facility; and
B. for a utility not subject to the commission's rate authority, the service associated with the applicable tariff in effect under Minnesota Statutes, section 216B.1611, subdivision 3, clause (2).

RIDER FOR PARALLEL GENERATION

TERMS AND CONDITIONS

1. The interconnection between the QF and the Company must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers.
2. The QF is responsible for complying with all applicable local, state, and federal codes, including building codes, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The Company requires proof that the QF is in compliance with the NEC before the interconnection is made. The QF must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.
3. The QF's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.
4. Any existing Interconnection Agreement executed between the Company and a QF with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract.
5. In accordance with Minnesota Rules 7835.5950, generators own all renewable energy credits unless other ownership is expressly provided for by a contract between the generator and the Company, state law specifies a different outcome, or specific commission orders or rules specify a different outcome.
6. Customers with a Distributed Energy Resource under 40 kW AC capacity shall execute a Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910. Additionally, customers with a Distributed Energy Resource of 40 kW AC capacity or greater and less than 1,000 kW AC capacity may execute the Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910 to elect an eligible rate. Customers with a Distributed Energy Resource less than 40 kW AC capacity and less than 10,000 kW AC capacity shall execute the Minnesota Distributed Energy Resource Interconnection Agreement with the Company. Before the Customer signs the Uniform Statewide Contract or the Minnesota Distributed Energy Resource Interconnection Agreement, the Company shall provide the Customer a copy of, or link to current interconnection standards in accordance with Minnesota Rules 7835.4750.
7. In accordance with Minnesota Rules 7835.4500, in case of a dispute between the Company and a QF or an impasse in the negotiations between them, either party may request the Minnesota Public Utilities Commission (MPUC) to determine the issue. When the MPUC makes the determination, the burden of proof must be on the utility. Fees and costs for dispute resolution shall be in accordance with Minnesota Rules 7835.4550.
8. QFs with Distributed Energy Resources more than 100 kW AC capacity may be required to take service under the Company's Rider for Standby Service, as described in the tariff.

RIDER FOR PARALLEL GENERATION

9. Customers with a Distributed Energy Resource sized between 40 kW AC capacity and 1,000 kW AC capacity taking service under the Rider for Parallel Generation will be required to install a separate production meter to record generation.

RIDER FOR STANDBY SERVICE

APPLICATION

Applicable to any Customer with on-site generation of 10 MW or less and taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75) and Large Power Service (Schedule 74) who has a distributed generation system which is able to generate on a continuous basis and who has entered into the "Minnesota Power's standard interconnection agreement" with the Company.

Service under this Rider shall be required for a Customer who has a distributed generation system that is run on a continuous basis and for non-emergency purposes which normally serves all or a portion of that Customer's electric load requirements, and who desires use of the Company's electric service for temporary backup. Exceptions to this Application include: (i) For any Customers with distributed generation systems rated at 100 kW or less, standby service will be available through their standard rate schedules; or (ii) any Customer, in lieu of service under this Rider, who provides physical assurance that standby service is not taken. A Customer requesting physical assurance shall agree to furnish and install an approved load limiting device which shall be set and sealed by the Company to prevent the Customer from utilizing standby service. The cost of the load limiting device shall be paid by the Customer.

The Customer shall execute a Standby Service Agreement with the Company for service under this Rider. The initial minimum term of service taken under this Rider shall be one (1) year. At the end of the initial term the contract will be automatically renewed on an annual basis, unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the initial term or any subsequent renewal thereof.

Energy provided to the Customer under this rider is limited to energy for Scheduled and Unscheduled Outages as defined below. The Customer shall not generate and allow energy flow onto the Company's system unless it is separately metered and permitted in accordance with the Company's Electric Service Regulations.

All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Service shall be taken at 60 hertz and at the voltage and phase relationship specified under the Company's applicable standard rate schedule for service to the Customer.

DEFINITIONS

Nominated Standard Service

Billed demand up to the level specified in the Standby Service Agreement under the Customer's standard rate schedule.

RIDER FOR STANDBY SERVICE

Reserved Standby Service
Maximum Scheduled Outage or Unscheduled Outage service allowed under this Rider for Standby Service as stated in the Standby Service Agreement. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

Excess Standard Service
Demand utilized in excess of the aggregation of the Customer's Nominated Standby Service and Reserved Standby Service billed on the Customer's standard rate schedule.

Scheduled Standby Service Demand
Measured demand during Scheduled Outages greater than the Nominated Standard Service that is not Excess Standard Service.

Unscheduled On-Peak Standby Service Demand
Measured demand during Unscheduled Outages and on-peak periods greater than the Nominated Standard Service that is not Excess Standard Service. On-peak periods shall include all hours between 6 a.m. and 10 p.m. Monday through Friday excluding holidays.

Unscheduled Off-Peak Standby Service Demand
Measured demand during Unscheduled Outages and off-peak periods in excess of Unscheduled On-Peak Standby Service Demand and greater than the Nominated Standard Service that is not Excess Standard Service. Off-peak periods shall include all hours not included in on-peak periods.

Generator Outage Rate
The unplanned generator outage expressed as a percentage. For the first twelve (12) months the Customer takes service under this Rider, such rate shall be the Equivalent demand Forced Outage Rate (EFORd) class average published on the Midcontinent Independent System Operator (MISO) website most similar to the Customer's generation. The EFORd measures the probability that a generating unit will not be available. For subsequent 12-month periods, the Generator Outage Rate will be calculated based on generator availability for the Customer's generating facilities within the previous 12-month period. The Generator Outage Rate for the Customer's generating facilities shall be calculated as the number of hours the generator was not available in the prior 12-month period excluding Scheduled Outages divided by the number of hours in a year.

Scheduled Outage
Planned outage periods that shall be prearranged by the Customer with the Company. Scheduled outages are available in April, May, October, November during any hours, and in all other months during off-peak hours between 10:00 p.m. and 06:00 a.m. Monday through Friday, and all hours on weekends and holidays. The Customer must provide at

RIDER FOR STANDBY SERVICE

least a 45-day notice of its proposed timeline for a Scheduled Outage. The Customer may modify the outage schedule with 45 days' notice to the Company.

Scheduled Outages may not exceed 60 days in any continuous 12-month period unless otherwise agreed to by the Company in writing. Any extension of the outage period may be requested by the Customer in writing and shall be responded to by the Company in writing.

Customers that do not comply with the terms and conditions for qualifying Scheduled Outage periods will be subject to Unscheduled Outage charges as defined below.

Unscheduled Outage
Any outage that occurs outside of the allowed months listed above or which occurs without a 45-day notice to the Company. Any usage above the Nominated Standard Service that does not occur during the Scheduled Outage periods as defined above or that exceeds the allowed number of Scheduled Outage days will be treated as an Unscheduled Outage.

RATE (Monthly)
The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Standby Reservation Fee ($/kW)
For purposes of applying the Standby Reservation Fee, the contracted Reserved Standby Service shall be the quantity specified by the Customer in the Standby Service Agreement with the Company. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

The Customer shall pay a Standby Reservation Fee equal to the rate specified below times the contracted Reserved Standby Service and multiplied by the Generator Outage Rate as stated in the Customer's Standby Service Agreement.

Standby Reservation Fee Rate

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	18.46	30.40
Primary	17.52	23.81	NA
Secondary	19.18	24.49	NA

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During months in which Scheduled or Unscheduled Outages occur, the Standby Reservation Fee shall apply only if the Standby Demand Charge as defined below is less than the Standby Reservation Fee.

Standby Demand Charge ($/kW)

The Standby Demand Charge shall be sum of Scheduled and Unscheduled Standby Demand Charges as defined below. During months in which Scheduled or Unscheduled Outages occur, the Standby Demand Charge shall only apply if the Standby Reservation Fee as defined above is less than the Standby Demand Charge.

Scheduled Outage

For purposes of applying the Standby Demand Charge during Scheduled Outages, the measured demand shall be determined during the 15-minute period of the Customer's greatest Scheduled Standby Service Demand during the billing month. To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the billing month and divided by the number of days in the billing month.

During Scheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate established in the standard rate schedule times the standby billing demand.

Unscheduled Outage

For purposes of applying the Standby Demand Charge during Unscheduled Outages, the demand shall be determined during the 15-minute periods of the Customer's greatest Unscheduled On- and Off-Peak Standby Service Demands during the billing month.

During Unscheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate defined below times the corresponding Unscheduled On- and Off-Peak Standby Service Demand.

On-Peak Standby Demand Charge

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	19.57	32.24
Primary	18.58	25.25	NA
Secondary	20.34	27.03	NA

RIDER FOR STANDBY SERVICE

Off-Peak Standby Demand Charge

Service Voltage Level \ Rate Schedule	General Service	Large Light and Power	Large Power
Transmission	NA	17.40	28.66
Primary	16.52	22.46	NA
Secondary	18.09	24.03	NA

Energy Charge

Scheduled Outage

The Customer shall pay for all energy usage during a Scheduled Outage according to their standard rate schedule, plus any applicable adjustments.

Unscheduled Outage

For all energy usage during an Unscheduled Outage, the Customer shall pay the Company's hourly incremental energy costs during the time of the sale, including third-party transmission costs incurred by the Company, plus an energy surcharge of $0.02 per kWh. Incremental energy costs are determined after assigning lower-cost energy to all firm retail and firm wholesale Customers including all inter-system pool sales which involve capacity on a firm or participation basis and to all interruptible sales to Large Power, Large Light and Power, and General Service Customers.

SERVICE CONDITIONS

1. All electricity delivered to the Customer by the Company shall be measured by one or more meters installed at a single point of common coupling or as determined by the Company. The Company's meter for standby service shall measure the flow of capacity and energy from the Company to the Customer only. Any flow of capacity and energy from the Customer to the Company shall be separately metered.

2. The Customer shall be required to pay the installation, operation, and maintenance costs incurred by the Company for the metering equipment installed on the Customer's generation equipment. Access shall be provided by the Customer to the Company for maintaining and operating such equipment.

3. The Company shall not be obligated to supply standby service to back up the Customer's distributed generation system at a level in excess of Reserved Standby Service. This restriction in no way limits the electric load requirements for which the Customer may require service from the Company under the standard rate schedule to which this Rider is attached.

RIDER FOR STANDBY SERVICE

4. Service shall be provided under this Rider if the Company has sufficient capacity available in existing production, transmission and distribution facilities to provide such service at the location where service is requested.

5. The Customer shall pay the Company the installed cost of any additional required facilities which are not supported by this Rider.

6. The Company may be reimbursed by the Customer for costs which are incurred, or which have been incurred, in providing facilities which were utilized principally or exclusively in providing service for any portion of the Customer's electric load requirements which are to be normally provided from the distributed generation system.

7. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

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Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Unscheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge
General Service			
Reservation Fee	N/A	$17.52 ($/kW)	$19.18 ($/kW)
On-Peak Demand Charge	N/A	$18.58 ($/kW)	$20.34 ($/kW)
Off-Peak Demand Charge	N/A	$16.52 ($/kW)	$18.09 ($/kW)
Energy Charge	N/A	incremental	incremental
Large Light & Power			
Reservation Fee	$18.46 ($/kW)	$23.81 ($/kW)	$25.49 ($/kW)
On-Peak Demand Charge	$19.57 ($/kW)	$25.25 ($/kW)	$27.03 ($/kW)
Off-Peak Demand Charge	$17.40 ($/kW)	$22.46 ($/kW)	$24.03 ($/kW)
Energy Charge	incremental	incremental	incremental
Large Power			
Reservation Fee	$30.40 ($/kW)	N/A	N/A
On-Peak Demand Charge	$32.24 ($/kW)	N/A	N/A
Off-Peak Demand Charge	$28.66 ($/kW)	N/A	N/A
Energy Charge	incremental	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.

RIDER FOR STANDBY SERVICE

Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule, plus any applicable adjustments:

Scheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments
General Service without a Demand Meter			
Reservation Fee	N/A	$17.52 ($/kW)	$19.18 ($/kW)
Demand Charge[1]	N/A	N/A	N/A
Energy Charge	N/A	9.332 (¢/kWh)	9.332 (¢/kWh)
General Service with a Demand Meter			
Reservation Fee	N/A	$17.52 ($/kW)	$19.18 ($/kW)
Demand Charge[1]	N/A	$8.00 ($/kW)	$8.00 ($/kW)
Energy Charge	N/A	6.507(¢/kWh)	6.507(¢/kWh)
Large Light & Power			
Reservation Fee	$18.46 ($/kW)	$23.81 ($/kW)	$25.49 ($/kW)
Demand Charge[1]	$9.50 ($/kW)	$9.50 ($/kW)	$9.50 ($/kW)
Energy Charge	4.574 (¢/kWh)	4.574 (¢/kWh)	4.574 (¢/kWh)
Large Power			
Reservation Fee	$30.40 ($/kW)	N/A	N/A
Demand Charge[1]	$29.43 ($/kW)	N/A	N/A
Energy Charge	2.778 (¢/kWh)	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.
[1] The demand charge is calculated based on a daily proration.

RIDER FOR STANDBY SERVICE

STANDBY BILLING EXAMPLES

Scheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Scheduled Standby Service Demand	2,000	kW
Outage Days	5	
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		Rate	Billing
Reservation Fee	200	kW	$ 18.46	$ 3,692.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
	2,000	kW	$ 9.50	$ -
	2,000	kW	$ (2.00)	$ -
*Scheduled Standby Service Demand * Standard Service Rate * (# of Outage Days/Days in Month)*				
Energy Charge	156,000	kWh	$ 0.04574	$ 7,135.44
	TOTAL STANDBY SERVICE BILLING			**$10,827.44**
Also subject to other applicable adjustments				

RIDER FOR STANDBY SERVICE

Unscheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Unscheduled Off-Peak Standby Service Demand	500	kW
Note: Customer standby demand peaked at 2,000 kW in off-peak hour		
Unscheduled On-Peak Standby Service Demand	1,500	kW
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		Rate	Billing
Reservation Fee	200	kW	$18.46	$0.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
Unscheduled Off-Peak Standby Service Demand	500	kW	$17.40	$8,700.00
*Unscheduled Off-peak Standby Service Demand * Off-peak Standby Demand Charge*				
Unscheduled On-Peak Standby Service Demand	1,500	kW	$19.57	$29,355.00
*Unscheduled On-peak Standby Service Demand * On-peak Standby Demand Charge*				
Energy Charge	156,000	kWh	$0.0550	$8,580.00
Company's hourly incremental energy costs during the time of sale				
Rate of $0.055 per kWh is for example purposes				
	TOTAL STANDBY SERVICE BILLING			**$46,635.00**
Also subject to other applicable adjustments				

RIDER FOR FOND DU LAC RESERVATION BUSINESS LICENSE FEE

APPLICATION

Applicable to billings for electric service provided within the Fond du Lac Reservation located in the southern portion of St. Louis County and the northern portion of Carlton County, Minnesota.

ADJUSTMENT

In accordance with the Corporate Code, Business License System and Employment Rights Law contained in the Fond du Lac Reservation Ordinance 5/84, businesses operating within the Reservation shall pay an assessment of 0.5 percent on revenues from sales within the Reservation. Therefore, there shall be added to each customer's monthly electric service bill a Fond du Lac Reservation Business License Fee assessment. The amount of the fee to be assessed shall be the applicable Assessment Rate multiplied by the Customer's bill for electric service. Compliance by Minnesota Power with the Business License System is governed by the terms of an agreement dated September 25, 1985, as amended by letter dated January 6, 1986, made with the Reservation Business Committee. Since the License Fee assessable by Minnesota Power applies retroactively to October 2, 1985, the initial Assessment Rate shall be 1.0 percent until such time as all retroactive amounts have been collected. Thereafter, the Assessment Rate shall be 0.5 percent.

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

APPLICATION

Applicable to bills for electric service under all Retail Rate Schedules except for Company's Competitive Rate Schedules 73 and 79. This Rider shall not be applicable to Economy or Standby service to retail customers.

Except as provided below in the CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section, there shall be added to each non-CIP exempt customer's monthly bill a Conservation Program Adjustment (CPA) charge which shall be the applicable CPA factor multiplied by the customer's monthly kWh of energy usage. The applicable CPA factor per kWh shall be determined annually as described below.

DETERMINATION OF THE CONSERVATION PROGRAM ADJUSTMENT FACTOR

The Conservation Program Adjustment factor shall be the quotient of the Recoverable Tracker balance, divided by projected retail energy sales (exclusive of those energy sales from customers who have been granted an exemption from CIP costs (see CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section). The CPA factor will remain in effect until subsequent MPUC approval of an updated factor. The Recoverable Tracker balance shall be determined by adjusting the prior year-end Conservation Improvement Program (CIP) Tracker balance by:

1) Subtracting the unamortized beginning CIP Tracker account balance;
2) Adding financial incentives awarded by the MPUC not reflected in the prior year-end balance;
3) Adding actual and anticipated CIP program expenditures at their approved and/or budgeted level for the applicable time period; and
4) Subtracting actual and anticipated CIP cost recovery through base rates, determined by multiplying the CCRC (shown below) by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the applicable time period; and
5) Subtracting actual and anticipated CIP cost recovery from the applicable CPA factor not accounted for in the prior year-end balance, as determined by multiplying the applicable CPA by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the remaining applicable time period. The remaining applicable time period for the applicable CPA is dependent upon subsequent MPUC approval which, for the purposes of this calculation, Minnesota Power assumes to align with the end of the current fiscal year (June 30, 2023).

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

All costs appropriately charged to the CIP Tracker account shall be eligible for recovery through this adjustment and all revenues received from the application of the CPA factor shall be credited to the CIP Tracker account.

In order to normalize the effect of significant changes in the CPA factor, the Company may request approval of an upper limit or cap on the calculated CPA factor.

The CPA factor effective August 1, 2023 for all non-CIP exempt customers shall be 0.0306¢ per kWh.

DETERMINATION OF CONSERVATION COST RECOVERY CHARGE (CCRC)

The CCRC is the amount included in base rates dedicated to the recovery of CIP costs as approved by the Minnesota Public Utilities Commission in the Company's last general rate case. The CCRC is approved and applied on a per kWh basis by dividing the test-year CIP expenses by the test-year sales volumes (net of CIP-exempt volumes). All revenues received from the CCRC shall be credited to the CIP Tracker Account.

The CCRC effective October 1, 2023 for all non-CIP exempt customers is 0.395703¢ per kWh.

CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS

For customers granted an exemption from CIP costs by the Commissioner of the Minnesota Department of Commerce, pursuant to Minn. Stat. § 216B.241, the CPA factor shall not be applicable. No CCRC is included in base rates for Large Power customers. For Large Power customers who have not been granted an exemption, the CCRC of 0.395703¢ per kWh shall apply to the total billing energy. In addition, non-Large Power customers who have been granted an exemption shall receive a billing credit of 0.395703¢ per kWh to offset the CCRC that is included in base rates under the applicable rate schedule. For those customer accounts granted exemption by a decision of the Commissioner after the beginning of a calendar year, any CIP collections billed after January 1 of the year following the Commissioner's decision shall be credited back to customers.

RIDER FOR NON-METERED SERVICE

APPLICATION

To General Service Schedules 25

DISCUSSION

Minnesota Power provides service for several types of operations that would normally be a part of the General Service class of customers. However, due to the unique nature of the customer's operations it is not always practical to meter the service points. Therefore, at Company's discretion, a customer may receive service under the General Service - Non-Demand Schedule without the metering requirements of that schedule and be billed for energy usage based on the table below. Additional end-use types and associated energy usages per unit may be added from time to time to address new situations. For purposes of applying the appropriate service charge, one service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required for service under the applicable General Service Schedule. In the case of Holiday decorative lighting, the customer shall be billed with a single service charge and energy usage per the table below one time per the holiday season, estimated at 45 operating days for 12 lighting hours per day.

Item Type	Description	Units	Estimated Monthly Energy Usage/Unit
SEC-CAM	Security Cameras	kWh	43 kWh
CBL2WY90	90v 2-Way Comm Cable PS	Volts	617 kWh
AMP-CBL	Amplifier Cable	Amplifiers	377 kWh
XFLSHR60	Crossing Flashers-60kWh	kWh	60 kWh
HS160W	Strip Heaters-160Watts	kWh	65 kWh
HSGREHRT	Strip Heaters-GRE Hartford 99	kWh	58 kWh
SIGN-LTG	Sign Lighting	Signs	25 kWh
SIRENS	Civil Defense Sirens	Sirens	1 kWh
RR-XING	Railroad Crossings	Crossings	39 kWh
NOWIRE15	Wireless Metering-15kWh	kWh	15 kWh

RIDER FOR NON-METERED SERVICE

HL-LED	Holiday Lighting – LED	kWh	270 kWh
HL-INCT	Holiday Lighting – Incandescent	kWh	3,780 kWh

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

APPLICATION

Applicable to any Customer taking service under General Service (Schedule 25) or Large Light and Power Service (Schedule 75) and which has at least 200 kW of Interruptible Load that qualifies for interruptible service. All provisions of the applicable standard Service Schedule shall apply to interruptible service under this Rider except as noted below.

RATE MODIFICATION

The Rates (Monthly) of the applicable General Service or Large Light and Power Service Schedules shall apply. Additionally, the Customer shall receive a billing credit which will be 11 percent of the Customer's interruptible billing before any other applicable Adjustments.

INTERRUPTIBLE ENERGY CONDITIONS

Interruptible energy must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur. During a Midcontinent Independent System Operator (MISO) emergency event the Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events. Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that is required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

PRICE RECALL CONDITIONS

The Company shall have the right to re-price the Customer's Interruptible Load energy at 110% of the Company's incremental supply cost for up to 100 hours per year. During a price recall period the Customer will be given the option to continue service without interruption under the terms of this Rider. The Company will provide day-ahead email notice by 4:00 p.m. Central Prevailing time on the day prior to the price recall period(s), which will include the estimated prices during the price recall period(s). The Customer will have the option to curtail during the re-pricing periods or continue normal operation and pay 110% of the incremental supply cost for all Interruptible Load during the re-pricing period. Re-pricing periods will occur between the hours of 6:00 a.m. to 10:00 p.m. with the exception of time periods when MISO has declared an alert or emergency for the Minnesota Power service area.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED PHYSICAL INTERRUPTION

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the targeted demand reduction

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

threshold specified in the Customer's annual contract. In the event that the Customer fails to follow an Interruption request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Interruption conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

SERVICE CONDITIONS

1. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than the Customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) at such other times when in the Company's opinion the reliability of the system is endangered,
   (d) when MISO declares an emergency event, or
   (e) when the Company performs necessary testing for certification of interruptibility of Customer's loads.

2. The Company shall not be liable for any loss or damage including consequential damages, caused by or resulting from any interruption of service.

3. The Customer must be able to physically interrupt its Interruptible Load when notified by the Company.

4. The Company may accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with the Module E Tariff and Business Practices Manual for Resource Adequacy. The Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the parties shall in good faith determine the most appropriate substitute and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either parties rights or obligations

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

under the Electric Service Agreement. Any changes would be subject to regulatory approval.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. The Customer shall pay the Company the installed cost of any additional facilities required which are not supported by this rate.

7. The term of service under this Rider shall be no less than one year and must be consistent with the MISO or successor Planning Year or other planning criteria as determined by the Company. However, the Company, at its sole discretion, reserves the right to provide the Customer with a three-month notice to discontinue providing service under this Rider.

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

APPLICATION

Applicable to any Customer taking service under Large Power Service Schedule 74, whose Electric Service Agreement has a minimum term of at least four (4) years beyond the initiation of Incremental Production Service hereunder and which provides for the sale by the Company and the purchase by the Customer of Incremental Production Service, subject to the conditions set forth in the Customer's Electric Service Agreement and this Rider. Application of this Rider and establishment of an Incremental Production Service Threshold ("IPST") for those Customers with self-generation and whose Electric Service Agreement allows for purchase of Economy Energy shall be at the sole discretion of the Company.

DEFINITIONS

Real-time Buy-through Period: Period called by the Company where Company will re-price Incremental Production Service ("IPS") energy and where Customer will respond through curtailing IPS load or buying-through at the real-time locational marginal price ("LMP").

Curtailment Period: Period called by the Company where Customer is required to curtail load.

Renewable Surplus Period: Period called by the Company during times of high renewable generation, low system load or low LMPs where Customer may exceed 110% of the IPST.

RATE MODIFICATIONS

Demand Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST but not greater than 110% of the IPST or has Measured Demand in excess of the IPST during a Renewable Surplus Period, the Customer's Measured Demand above the IPST shall not be subject to any demand charges or ratchet provisions associated with Contract Demand and Incremental Service Requirements under the Large Power Service Schedule and the Customer's Electric Service Agreement unless otherwise provided in this Rider or the Customer's Electric Service Agreement. If Customer has Measured Demand in excess of the IPST during a Curtailment Period, the Customer's Billed Demand will be increased by the amount the Measured Demand exceeded the IPST, and the Customer will be subject to any penalties imposed upon Company by the Midcontinent Independent System Operator ("MISO") or a successor entity relating specifically to Customer's failure to curtail IPS service.

Energy Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST, the energy associated with the Customer's Measured Demand above the IPST shall

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

be subject to an energy charge equal to the Incremental Production Rate, the Real-time Buy-through Period Rate or the Curtailment Period Rate.

Incremental Production Rate
The Incremental Production Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly day-ahead LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate.

Real-time Buy-through Period Rate
The Real-time Buy-through Period Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate.

Curtailment Period Rate
The Curtailment Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate.

Renewable Surplus Period Rate
The Renewable Surplus Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate.

Excess Reactive Demand
Whenever a Customer's metered demand exceeds the IPST, the Company shall not bill the Customer for any excess reactive demand adjustments below the level specified in the Customer's Electric Service Agreement. However, the Company may, at its sole discretion, bill the Customer for any excess reactive demand adjustments above the specified level at the Excess Power Demand Charge, with excess reactive demand calculated as indicated in the Large Power Service Schedule.

SERVICE CONDITIONS

1. All curtailments, buy-throughs, or Company declarations of Curtailment Periods or Renewable Surplus Periods can be superseded by Company requests of Customer to curtail load as soon as reasonably possible for purposes of grid stability, in accordance with Company's Service Regulations.

2. The Customer shall be permitted to purchase Incremental Production Service from the Company, for service above the IPST established in the Electric Service Agreement,

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

whenever the Customer's Measured Demand during any Billing Month exceeds the IPST, with the exception of during Curtailment Periods.

The Customer's Measured Demand shall not exceed 110% of the IPST without the Company declaration of a Renewable Surplus Period or Company's prior written consent, which consent shall not be unreasonably withheld. In the event that the Customer exceeds this level without Company consent or outside of Renewable Surplus Periods, the Company may increase the Customer's contractual requirements, including Contract Demand, IPST, or other related terms, by that amount for the duration of the Customer's Electric Service Agreement.

Additional Service Conditions for Real-time Buy-through Periods

3. Upon notification from the Company of a Real-time Buy-through Period, the Customer has the option of reducing its metered demand to the IPST by the time given by the Company or have the Incremental Production Service energy repriced at the Real-time Buy-through Rate. The Customer shall be given 30 minutes or greater notice of a Curtailment Period.

4. Real-time Buy-through Periods will not be called for greater than 170 hours per calendar year, excluding MISO capacity event curtailments.

5. The duration and frequency of Real-time Buy-through Periods shall be at the sole discretion of the Company. Real-time Buy-through Periods shall normally occur during times of high or volatile real-time LMPs or low generation.

Additional Service Conditions for Curtailment Periods

6. Upon notification from the Company of a Curtailment Period, the Customer shall reduce its metered demand to the IPST by the time given by the Company, and for a duration as required by the Company. The curtailment shall be for the entire amount of Incremental Production Service unless otherwise notified by the Company. The Company shall give Customer 30 minutes or greater notice of a Curtailment Period. Thirty (30) minute notification under this Rider shall be via automatic control unless otherwise provided in the Customer's Electric Service Agreement.

7. Curtailment Periods will not be called for more than 170 hours per calendar year, excluding MISO capacity event curtailments.

8. Curtailment Periods will not be called for more than eight hours per day and no more than four hours per Curtailment Period.

9. The duration and frequency of Curtailment Periods shall be at the sole discretion of the Company. Curtailments shall normally occur for reasonable testing requirements, at such times when the Company expects to incur a system peak in excess of its MISO (or successor organization) accredited generating capability (less the required planning reserve) and at such other times when, in the Company's opinion, the

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

reliability of the Company or MISO systems are endangered. Curtailments shall normally not occur due to high energy costs. Curtailments shall normally occur for capacity related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service Customers (those loads that meet the requirements as specified in the MISO (or successor organization) procedure for the certification of interruptible demand). Unless agreed to in advance by the Customer, the Company shall not make additional non-firm off-system energy sales that would, if made, require curtailment of Incremental Production Service.

10. The Customer shall pay any and all penalties or other costs incurred by the Company if the Customer fails to reduce its metered demand to the IPST or the requested reduction level (but not less than the IPST) within 30 minutes of receiving such notice from the Company. The penalties or other costs shall be divided pro rata between those Customers that did not curtail service as requested by the Company.

11. The Company shall reserve the right to discontinue service under this Rider to Customers who fail to curtail service as requested by the Company.

12. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

Additional Service Conditions for Renewable Surplus Periods

13. Upon notification from the Company, Customer may exceed 110% of the IPST for a duration determined at the sole discretion of the Company. The Customer shall be given, whenever possible, information regarding the probable time and duration of Renewable Surplus Periods the calendar day prior to any such period. Notice may also be given with at least a 30 minute notice.

14. The duration and frequency of Renewable Surplus Periods shall be at the sole discretion of the Company. Renewable Surplus Periods may occur during times of high renewable generation or low MP system load.

15. The Company may cancel Renewable Surplus Periods with 30 minutes notice if MISO or MP system conditions change.

RIDER FOR RELEASED ENERGY

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74. Application of this Rider and establishment of Released Energy Credit shall be at the sole discretion of Company and participation by Customer is voluntary.

RATE MODIFICATIONS

Energy Credit for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Large Power Service requirement, the Released Energy Credit shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

Energy Credit for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a Released Energy Credit for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The Released Energy Credit shall equal a fair market value for the hours of the release.

The Released Energy Credit shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

CONDITIONS

1. Customer may not purchase Large Power Incremental Production Service ("IPS") as established under the Rider for Large Power Incremental Production Service while participating in Released Energy Credit opportunities.

2. If Customer makes energy available for sale and the identified released energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the Released Energy Credit shall be zero. In the event that a scheduled released energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

3. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is released for sale or an avoided energy purchase is completed.

RIDER FOR RELEASED ENERGY

4. When Released Energy Credit opportunities are anticipated, Company shall provide advance notice, if possible, of the approximate margins or available energy purchase costs and hours of sale or purchase opportunity available to Customers who have indicated interest. Opportunities for voluntary load reductions will be communicated to customers primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. If two or more notified customers make energy available for sale for the same time period, Company will prorate the Released Energy Credit among those customers. Released Energy Credits shall be determined for each Customer according to the amount of capacity made available for sale by each in proportion to the total amount of capacity made available by all Customers for a given time period.

5. In the event that additional released energy sales or avoided energy purchase opportunities arise during a day, Company shall provide Customers with as much advance notice as possible (via email and phone calls) to enable their participation. Credits associated with such opportunities shall be allocated to Customers on a first-come, first-served basis.

6. Customer may notify Company when Customer desires to reduce energy requirements for released energy sales or avoided energy purchase opportunities. Customer may have a “standing agreement” with Company regarding the conditions for Released Energy Credit opportunities, allowable duration, required margins, margin sharing, etc. These agreements, may be made on a customer by customer basis and shall be considered by Company without notice to other customers.

7. Energy shall be made available for sale in increments of 5 MW with a 10 MW minimum and shall be associated with actual reduced power requirements.

PENALTY FOR INSUFFICIENT LOAD CONTROL

In the event that Company has entered into a sale or purchase agreement for energy made available by a Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the released energy sale or avoided energy purchase, Customer shall receive no credit for the time that load exceeded the specified level and shall be responsible for any and all costs incurred by Company due to such failure to control load.

RIDER FOR VOLUNTARY ENERGY BUYBACK

APPLICATION

Applicable to any Customer eligible for service under General Service Schedule 25; Large Light and Power Service Schedule 75 (and including all applicable Riders thereto); or Competitive Rate Schedules 73 or 79, and customers receiving service under contracts authorized by Minn. Stat. §216B.162 (the competitive and discretionary rate statute). Customer must be able to provide a minimum of 200 kW of curtailable demand for energy buyback transactions. Energy buyback transactions facilitate short-term off-system energy sales or assist in avoiding higher-cost energy purchases to meet Company's firm energy requirements. Application of this Rider and establishment of Buyback Energy Credit ("BEC") shall be at the sole discretion of Company. Participation by Customer is voluntary. All provisions of the applicable standard Service Schedule shall apply to service under this Rider except as noted below.

RATE MODIFICATION

Customer shall receive a BEC for any calendar month in which Customer and Company have agreed to participate in energy buyback transactions. The BEC shall occur as an adjustment on Customer's bill and shall consist of a payment per kWh for each hour subject to an energy buyback transaction.

BEC for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Service requirement, the BEC shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

BEC for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a BEC for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The BEC shall equal a fair market value for the hours of the release.

The BEC shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

RIDER FOR VOLUNTARY ENERGY BUYBACK

SERVICE CONDITIONS

1. Company and Customer shall enter into an Energy Buyback Agreement specifying the rates, and the terms and conditions, for participation in energy buyback transactions, including, but not limited to: (i) BEC calculation; (ii) period of possible energy buyback; (iii) minimum/maximum duration of each energy buyback; and (iv) commencement/ termination notice requirements.

2. Company and Customer shall agree to a typical peak kW level of operation ("Reference Operating Level"). Customer shall determine an acceptable reduced operating level for each energy buyback transaction time period ("Reduced Operating Level"). The amount of energy associated with each energy buyback transaction shall be equal to the difference between Customer's Reference Operating Level and the Reduced Operating Level multiplied by the hours of curtailment at a load factor mutually agreed to by Company and Customer.

3. Company shall notify Customer of energy buyback opportunities primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. Alternatively, Customer may notify Company when Customer desires to reduce energy requirements for energy buyback transactions.

4. Under the terms of the Energy Buyback Agreement, at Company's request, Customer shall curtail down to the Reduced Operating Level for a duration as required by Company, such duration not to exceed the maximum number of curtailment hours agreed to by Company and Customer. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is made available for sale or an avoided energy purchase is completed.

5. Customer shall pay Company the installed cost of any additional facilities (e.g., metering, protective devices for interconnection with Company's system, etc.) required to participate in energy buyback transactions under this Rider.

6. If Customer makes energy available for sale and the identified off-system energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the BEC shall be zero. In the event that a scheduled off-system energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

7. In the event that Company has entered into a sale or purchase agreement for energy made available by Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the buyback energy sale or avoided energy purchase, (i) Customer shall receive no credit for that calendar month in which the curtailment failure occurred, and (ii) Customer shall be responsible for any and all costs incurred by Company

RIDER FOR VOLUNTARY RENEWABLE ENERGY

APPLICATION

Application to customers taking service under all retail rate schedules. All provisions of the applicable standard Service Schedule shall apply to renewable energy service under this Rider except as noted below. The renewable energy service provided under this schedule is subject to the availability of renewable energy designated to it, as determined by the Company, and is made available on a first-come, first-served basis. “Renewable energy” means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary.

RATE MODIFICATIONS

The Rates (Monthly) and all adjustments included in the applicable service Schedule shall apply. Additionally, the Customer shall pay a monthly renewable energy surcharge for each kWh of renewable energy nominated, and shall receive a credit for the rate-class-specific monthly Fuel and Purchased Energy Charge.

DETERMINATION OF THE RENEWABLE ENERGY SURCHARGE

The renewable energy surcharge shall be based on the total program costs including the sum of:

[b] The cost of renewable energy that will supply the program,

[c] The delivery costs,

Divided by

[a] The expected annual energy output.

The renewable energy surcharge will be recalculated annually to reflect power supply costs. An example of the calculation is shown below in Appendix 1.

Renewable Energy Surcharge

$0.03900 per kWh – All Customer Classes

The charge per kWh is in addition to the applicable Service Schedule currently serving the customer. All charges under existing tariffs remain in effect.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

SERVICE CONDITIONS

1. The Customer may nominate between 25% and 100% of their monthly kWh use.
2. The Customer shall take service under this Rider for no less than one year. Service shall continue thereafter until and unless the Customer notifies the Company that service under the Rider is to be terminated.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

Appendix 1

MINNESOTA POWER
Sample of
Renewable Rate Pricing Calculation

Power Supply Cost:

[a] Expected annual energy output (PPA)	xx kWh
[b] Cost of Renewable energy to supply program (per PPA guidelines)	$xx
[c] Delivery Cost of renewable energy	$xx
[d] Renewable Energy Surcharge ([b] + [c]) / [a]	$xx per kWh

RIDER FOR CITY OF LONG PRAIRIE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Long Prairie, except bills for electric service to property owned by the City of Long Prairie.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Long Prairie Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Long Prairie Franchise Fee assessment collected will be passed along to the City of Long Prairie.

RIDER FOR CITY OF LITTLE FALLS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Little Falls, except bills for electric service to property owned by the City of Little Falls.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Little Falls Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Little Falls Franchise Fee assessment collected will be passed along to the City of Little Falls.

RIDER FOR CITY OF HERMANTOWN FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hermantown, except bills for electric service to property owned by the City of Hermantown and property owned or leased by Company.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hermantown Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Hermantown Franchise Fee assessment collected will be passed along to the City of Hermantown.

RIDER FOR CITY OF PARK RAPIDS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Park Rapids, except bills for electric service to property owned by the City of Park Rapids.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Park Rapids Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuels meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Park Rapids Franchise Fee assessment collected will be passed along to the City of Park Rapids.

RIDER FOR CITY OF AURORA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Aurora, except bills for electric service to property owned by the City of Aurora.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Aurora Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Aurora Franchise Fee assessment collected will be passed along to the City of Aurora.

RIDER FOR DISTRIBUTED GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: Residential Service (Schedule 20), Residential Dual Fuel Interruptible (Schedule 21), Commercial/Industrial Dual Fuel Interruptible (Schedule 26), General Service (Schedule 25), Large Light and Power Service (Schedule 55, 75), Municipal Pumping Service (Schedule 87) and Large Power Service (Schedule 54, 74) and who has entered into Minnesota Power's standard interconnection agreement with the Company for the operation of the on-site interconnection of a Distributed Energy Resource operating in parallel with the Company's distribution system. The Distributed Energy Resource must be:

a. an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site; and

b. fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10 MW of interconnected capacity at a point of common coupling to Company's distribution system. The interconnection and operation of Distributed Energy Resources at each point of common coupling shall be considered as a separate application of the Rider.

Service under this Rider shall be required for any Customer who meets the Application criteria in the previous paragraph, subject to the following exceptions: (i) any Customer who takes service, as applicable, under Company's Rider for Parallel Generation as established under Minnesota Rules Chapter 7835 – Cogeneration and Small Power Production; or (ii) any Customer, in lieu of service under this Rider, who pursues reasonable transactions outside this Rider as agreed to by Company and Customer.

Customer shall execute an electric service agreement and a power purchase agreement with Company for service under this Rider. The minimum term of service taken under this Rider shall be one (1) year or such longer period as may be required under the electric service agreement. Service under this Rider is subject to Company's Electric Service Regulations and any other rules as applicable. All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Output of the Distributed Energy Resource shall be provided at 60 hertz and at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer or as agreed to by Company and Customer.

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

Service Charge: $15.83

RIDER FOR DISTRIBUTED GENERATION SERVICE

Capacity/Energy Credits:

Customer may sell all the energy produced by the Distributed Energy Resource to Company, use all the Distributed Energy Resource energy to meet its own electric load requirements or use a portion of the energy from the Distributed Energy Resource and sell the remaining to Company.

Company shall purchase all capacity and energy made available by Customer from the Distributed Energy Resource. Such capacity and energy shall be purchased by Company under the rates, terms and conditions for such purchases as established by Company in a power purchase agreement with Customer.

Capacity Credits shall only be provided on that capacity available to Company which meets the accreditation requirements of the Midcontinent Independent System Operator (MISO) or successor organization.

Capacity and Energy Credits shall be based on Company's calculation of avoided capacity and energy costs. The Capacity Credits in effect at the time Customer enters into a power purchase agreement with Company shall remain in effect for the length of the agreement. Energy Credits for use under the power purchase agreement shall vary by month and time period (on-peak and off-peak) and shall be updated annually for the upcoming calendar year. Upon written request by Customer and after Customer signs a confidentiality agreement, Company shall provide Customer the current schedule of Capacity and Energy Credits.

Delivery Charge ($/kw):

Company may require any Customer with a Distributed Energy Resource of 1 MW or greater nameplate capacity rating to pay a Delivery Charge for all capacity and energy made available by Customer from the Distributed Energy Resource. Such Delivery Charge shall compensate Company for any additional distribution, transmission and ancillary services not included under this Rider provided by Company to Customer through Company's participation in the MISO or successor organization. For applying the Delivery Charge, the capacity shall be determined during the 15-minute period of Customer's greatest capacity delivered to Company during the billing month.

Distribution Credits:

If the installation of the Distributed Energy Resource results in Company delaying or avoiding distribution investment, Company shall provide Distribution Credits to Customer that reflect the avoided distribution cost.

Company shall provide, upon Customer's written request, a list of substation areas or feeders that could be likely candidates for Distribution Credits as determined through Company's normal distribution planning process. Upon receiving an application from

RIDER FOR DISTRIBUTED GENERATION SERVICE

Customer for the interconnection and operation of a Distributed Energy Resource, Company shall perform an initial screening study to determine if the project has the potential to receive Distribution Credits. Customer shall be responsible for the cost of such screening study. If Company's initial study shows that there exists potential for Distribution Credits, Company shall, at its own expense, pursue further study to determine the Distribution Credits, as part of its annual distribution capacity study.

Line Loss Credits:

If the installation of the Distributed Energy Resource results in Company avoiding additional line losses, Company shall provide Line Loss Credits to Customer that reflect the additional line loss savings.

Company shall perform, upon Customer's written request, a specific line loss study to determine if the project has the potential to receive Line Loss Credits. Customer shall be responsible for the cost of such line loss study.

Renewable Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company meeting a requirement to obtain renewable capacity and energy, Company shall provide Renewable Credits to Customer that equal the additional avoided cost of the renewable addition or purchase. The purchase price of such Renewable Credits shall be net of payment for capacity and energy identified above.

In the event that Customer producing the power receives renewable credits, (that is, the Customer is paid by the Company the avoided cost of renewable energy purchases), then the transaction represented by the power purchase agreement will constitute a transfer from the Customer to the Company of the property rights, for those renewable attributes specific to the renewable energy generated by the Customer and for which the Company paid renewable credits.

Customer may receive either renewable credits or tradable emission credits but not both.

Tradable Emission Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company receiving an economic value associated with tradable emissions, Company shall provide Tradable Emission Credits to Customer that equal the credit revenues associated with the Distributed Energy Resource of such Tradable Emission Credits received by Company. Customer may receive either renewable credits or tradable emission credits but not both.

In the event that Customer producing the power receives tradable emission credits, then the transaction represented by the power purchase agreement will constitute a transfer from the

RIDER FOR DISTRIBUTED GENERATION SERVICE

Customer to Company of the property rights, if any, for those tradable emission credits received by Customer and for which Company paid tradable emission credits.

SERVICE CONDITIONS

1. All electricity delivered to Company by Customer shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. Company's meter for distributed generation service shall measure the flow of capacity and energy from Customer to Company only. Any flow of capacity and energy from Company to Customer shall be separately metered.

2. Service shall be provided under this Rider if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

3. Customer shall pay Company the installed cost of any additional required facilities which are not supported by this Rider.

4. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Company Distributed Energy Resource process and technical documents are available at www.mnpower.com or by contacting Company at 1-800-228-4966 or 30 West Superior Street, Duluth, MN 55802.

RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	\$2.04 per kW-month for all Billing Demand kW and 0.275¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.380¢ per kWh for all kWh

RIDER FOR TRANSMISSION COST RECOVERY

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$0.36 per kW-month for all Billing Demand kW and 0.047¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.195¢ per kWh for all kWh

RIDER FOR CITY OF STAPLES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Staples.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Staples Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Staples, which is currently 5% of the total bill excluding sales taxes. The fee is listed on the bill as "Staples Franchise Fee (5%)" and is effective as of March 11, 2010.

100% of the City of Staples Franchise Fee assessment collected will be passed along to the City of Staples.

RIDER FOR CITY OF NASHWAUK FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Nashwauk.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Nashwauk Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Nashwauk, which is currently 1.5% of the total bill excluding sales taxes. The fee is listed on the bill as "Nashwauk Franchise Fee (1.5%)" and is effective as of February 10, 2011.

100% of the City of Nashwauk Franchise Fee assessment collected will be passed along to the City of Nashwauk.

RIDER FOR FOUNDRY, FORGING AND MELTING CUSTOMERS

APPLICATION

Applicable to any customer in the Foundry, Forging, and Melting Industry, as determined by Company, taking service under Large Light and Power Service (Schedule 75).

Customers taking service under this Rider may not also take service under the Rider for General Service/Large Light and Power Interruptible Service.

The term of service under this Rider shall be no less than one year. Customers must provide 30 days advance notice to Company prior to taking service under this Rider or discontinuing service under this Rider after at least one year of service.

This Rider shall apply to the entire electric service requirements on Customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

RATE MODIFICATION

Demand Charge Credit: For each month that service is taken under this Rider, the Customer shall receive a billing credit of $3.00 per kW of Billing Demand.

Price Recall Energy: 200 Hours of Price Recall Energy per calendar year will be billed at Company's sole discretion subject to the following conditions.

- Minimum of three hours duration per price recall period.
- Price Recall hours will be limited to 6 a.m. to 10 p.m. Central Prevailing Time with the exception of time periods when Midcontinent Independent System Operator (MISO) (or successor) has declared an alert or emergency for the Minnesota Power area.
- Minnesota Power will provide day-ahead email notice by 4 p.m. Central Prevailing Time on the day prior to the price recall period(s). The notice will indicate the start and stop times for the price recall period(s) and estimated prices during these price recall period(s).
- Customer has the option to curtail load or to continue normal operations during the price recall period.
- Price Recall energy usage will be billed at 110% of the Company's hourly incremental energy costs during the time of the price recall period. Incremental energy costs are determined after assigning lower cost energy to all firm retail and firm wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis.

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

APPLICATION

Applicable to any customer taking service under Large Light and Power Service Schedule 75 with total power requirements of at least 3,000 kW. Application of this Rider shall be at the sole discretion of Company. All provisions of the Large Light and Power Service Schedule shall apply to the Time-of-Use service under this Rider except as noted below. Participation by customer is voluntary.

Customers taking service under this Rider may not also take service under the Rider for Parallel Generation or the Rider for General Service/Large Light and Power Interruptible Service.

RATE MODIFICATION

The monthly rate will be modified as follows:

Demand Charge

For the first 100 kW or less of On-Peak Billing Demand	$1,050.00
All additional On-Peak Billing Demand ($/kW)	$10.00
Off-Peak Demand in excess of On-Peak Billing Demand ($/kW)	$4.50
Super Off-Peak Demand in excess of Off-Peak Billing Demand ($/kW)	$0.00

Transmission Demand Charge ($/kW)

On-Peak Transmission Demand	$4.00

Energy Charge

On-Peak kWh (¢/kWh)	6.399¢
Off-Peak kWh (¢/kWh)	4.267¢
Super Off-Peak kWh (¢/kWh)	3.201¢

Modified Determination of Billing Demand

On-Peak Billing Demand shall be the kW measured during the 15-minute period of the customer's greatest On-Peak use during the month, as adjusted for power factor, except that On-Peak Billing Demand will not be less than 75% of the greatest adjusted On-Peak demand during the preceding eleven months, nor shall it be less than any Minimum Contract Demand that may be specified in customer's Electric Service Agreement.

The Off-Peak Billing Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak or Off-Peak) during the current month, as adjusted for power factor, and the On-Peak Billing Demand.

The Super Off-Peak Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak, Off-Peak,

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

or Super Off-Peak) during the current month, as adjusted for power factor, and the On-Peak and Off-Peak Billing Demand.

SERVICE CONDITIONS

1. On-Peak, Off-Peak, and Super Off-Peak Periods Defined: The On-Peak time period shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super-Off Peak period shall be defined as 11:00 p.m. to 5:00 a.m CPT. The Off-Peak time period shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

2. At the end of the first year following the initial date when any customer takes service under this Rider, the applicability, rate modification, and service conditions will be evaluated for potential modification. The Rider will continue in effect after the initial year until it has been modified or cancelled based on the evaluation of the pilot.

3. The term of service under this Rider shall be no less than one year unless the pilot offering is terminated prior to the conclusion of customer's first year of service.

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

APPLICATION

Applicable to any Residential Service Customer taking service under Rate Code 20 (General) or Rate Code 22 (Space Heating) who is approved as qualified for the Low Income Home Energy Assistance Program (LIHEAP) by a designated social service agency (Agency) within Company's service territory during the program year (October 1 to September 30). Customers must receive certification annually through authorized Agency to be eligible for this Rider. A qualification exception applies for customers who initially self-declare as low income. Continued eligibility for the CARE program, beyond the initial exception, would be subject to customers requesting and being approved for LIHEAP within one year of their low income self-declaration.

DEFINITIONS

SENIOR Customers:
Seniors are those age 62 or older, as determined through the LIHEAP qualification and/or Low Income Self-Declaration process.

DISABLED Customers:
Disabled are those determined as disabled through the LIHEAP qualification and/or Low Income Self-Declaration process.

LEGACY CARE Customers:
Customers enrolled in the CARE Program as of September 30, 2019 or prior to the initial offering of the flat and affordability discounts under this Rider, whichever is later.

RATE MODIFICATION

All provisions of the Residential Service Schedule shall apply except as modified below:

FLAT DISCOUNT

Eligible Senior, Disabled, and / or Legacy CARE customers receive a $20 flat discount in each monthly billing period.

AFFORDABILITY DISCOUNT

Eligible Senior and / or Disabled Customers Under 62 Years of Age with no Disability, and Customers with certified medical circumstances:

A customer using more than 3% of their annual household income for electric bill payments may be eligible for the Company's affordability discount. The Company will offer customers with the lowest income, and a history of high electric consumption, an affordability discount

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

with the goal of keeping a household's annual energy burden within 3% of its income, on average. The affordability discount will be applied as a monthly percentage discount on bill.

LOW-INCOME AFFORDABILITY PROGRAM SURCHARGE

For Customers taking service under: Residential Service (Rate Code 20, 22, and 23) except those residential customers who are qualified for LIHEAP, General Service (Rate Code 25), Large Light & Power (Rate Code 75), Large Power (Rate Code 74), and Non-Contract Large Power (Rate Code 78) there shall be added to each service agreement, as designated above, on their monthly bill, a Low-Income Affordability Program Surcharge as specified below:

Residential (Except LIHEAP-qualified)	$2.41
General Service	$4.01
Large Light & Power	$26.74
Large Power	$1,826.31

SERVICE CONDITIONS

1. In order to determine customer eligibility for this Rider, the Company will review customer's LIHEAP approval and/or Low Income Self-Declaration status, Customer billing information, approved LIHEAP benefits, household income, and / or arrears.

2. For Legacy CARE and Affordability Discount Customers, any past due bills for electric service will be spread over a maximum of 24 months and shall be put in a 24-month payment arrangement under the Arrearage Forgiveness program.

3. Customers taking service under this Rider will be encouraged to participate in Minnesota Power's energy conservation programs.

4. Customers must be LIHEAP eligible by May 1 of each program year to continue receiving service under this Rider. The program year starts October 1 and ends September 30 of the following year.

5. Customers who become eligible through the Low Income Self-Declaration process must request and be determined eligible for LIHEAP within one year of their initial low income self-declaration in order to remain eligible for this Rider.

6. Customer must maintain an active account registered under Customer's name with the Company to be eligible for this Rider.

7. Qualified Customers are eligible to receive a discount under this Rider at only one residential location at any one time, and the Rider applies only to a qualified

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

Customer's primary residence. This Rider will not be available when, in the opinion of the Company, the Customer's residency or occupancy is of temporary nature.

8. It is the Customer's responsibility to notify the Company if there is a change of address or eligibility status.

9. Application of this Rider shall be prospective, and the Rider discount shall not be applicable to past due bills.

10. If the participating Customer misses two consecutive payments, the Customer will be removed from this Rider and will become subject to standard collection activities for any past due amounts.

11. Refusal or failure of a Customer or Agency to provide documentation of eligibility acceptable to the Company may result in Customer removal from this Rider.

12. Customer may be re-billed for periods of ineligibility under the applicable standard rate schedule.

13. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 15 on low income affordability programs.

ARREARAGE FORGIVENESS CONDITIONS

1. Current Legacy CARE and Affordability Discount participants with past-due arrears balances that satisfy Service Condition 1 are eligible for Arrearage Forgiveness.

2. Potential Arrearage Forgiveness applies to outstanding arrears at the time of CARE enrollment or as of the effective date of the Arrearage Forgiveness component, whichever is later.

3. The Arrearage Forgiveness shall in no event exceed the outstanding arrears balance.

4. The Company shall total the amount of arrears payments made by all CARE customers each month, and based on available funds in the CARE Rider Tracker, shall determine the percentage matching rate and shall match each Customer's monthly paid arrears amount by applying the determined percentage to reduce arrears in the same month. The initial matching rate will be 100 percent.

5. In the event a Customer applies, qualifies and receives fuel assistance, the fuel assistance amount may be used to pay the arrears amount. The Company shall not match amounts paid by a third party; however, any amount of arrears paid by the Customer any

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

month shall be matched by the Company by applying the percentage of reduction in place as stated in Arrearage Forgiveness Condition 4 above.

6. If a Customer has new arrears, it means the Customer has missed at least two consecutive payments, therefore, Service Condition 9 applies, and the Customer shall no longer be eligible for the CARE Program or the Arrearage Forgiveness component.

RIDER FOR CITY OF SILVER BAY FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Silver Bay, except bills for electric service to property owned by the City of Silver Bay, for the period from January 1, 2014 to December 31, 2024.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Silver Bay Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Silver Bay Franchise Fee assessment collected will be passed along to the City of Silver Bay.

RIDER FOR CITY OF HOYT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hoyt Lakes, except bills for electric service to property owned by the City of Hoyt Lakes, for the period from October 2015 to October 2035.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hoyt Lakes Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Hoyt Lakes Franchise Fee assessment collected will be passed along to the City of Hoyt Lakes.

RIDER FOR SOLAR ENERGY ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f), hereby defined as Solar-Paying Customers.

SOLAR ENERGY ADJUSTMENT

The Solar Energy Adjustment (SEA) shall be added to or deducted from each Solar-Paying Customer's monthly bill in an amount per kilowatt-hour determined as described below.

The SEA shall be calculated each month using data for the first two of the preceding three months as follows:

(a) Cost of solar energy purchased,
(b) Plus a credit for fuel and purchased energy costs included in the Rider for Fuel and Purchased Energy Adjustment (FPE Rider). The credit is an adjustment for cost already collected through the FPE Rider, including the Time of Generation Adjustment (TOGA). This credit is determined by multiplying the solar energy generation by the TOGA-adjusted FPE Adjustment (e) and adding the TOGA (d) as defined below.

Total of (a) and (b) shall be divided by the total kilowatt-hour sales for Solar-Paying Customers for the first two of the preceding three months.

TIME OF GENERATION ADJUSTMENT

The TOGA shall quantify the value of the time of generation for solar energy in order to compensate Solar-Paying Customers based on the time the solar energy is produced. The TOGA shall be added to the FPE cost and the resulting TOGA-adjusted FPE Adjustment shall be calculated in the FPE Rider as follows and applied to all customer energy usage:

(c) Calculate the FPE Adjustment without solar ($/MWh) by dividing the FPE costs excluding solar costs ($) by the non-solar energy generation (MWh);

RIDER FOR SOLAR ENERGY ADJUSTMENT

(d) Calculate the TOGA by multiplying the TOGA Factor as determined below by the solar energy generation and by the FPE Adjustment without solar;
(e) Calculate the TOGA-adjusted FPE Adjustment by adding the TOGA to the FPE costs excluding solar costs and dividing this sum by non-solar energy generation.

TIME OF GENERATION ADJUSTMENT FACTOR

The TOGA Factor shall be determined as follows:

(f) Calculate the simple average of actual non-solar energy cost ($/MWh) for the first two of the preceding three months by dividing total monthly costs of non-solar generation by total monthly non-solar MWh sales;
(g) Calculate the total hourly solar energy generation (MWh) for the first two of the preceding three months;
(h) Calculate the weighted average solar generation cost by multiplying each hourly projected avoided energy cost ($/MWh) by the associated solar energy generation amount (MWh) and then summing the total for the month ($);
(i) Calculate the weighted average solar energy generation cost ($/MWh) by dividing (h) by (g);
(j) Calculate the TOGA Factor by dividing (i) by (f) and subtracting 1.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

APPLICATION

This Rider shall be applicable on an optional basis to any retail customers who are not exempt from Solar Energy Standard obligations under Minnesota Statute § 216B.1691, subd. 2(d).

RATE (Monthly)

The Customer may choose one of the following options for charges and credits which shall be applicable in addition to all charges for service being taken under Company's standard rate schedule.

Option 1. Upfront Payment per kW

Customer shall pay a one-time subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy kilowatt-hours (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$2,132.15 per subscribed block.
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 2. Monthly Subscription per kW

Customer shall pay a monthly subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$15.62 per subscribed block per month
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 3. Fixed Charge per kWh

Customer shall pay a charge for the energy the customer's subscribed portion of the solar garden generates. The charge shall be as follows:

Fixed kWh Charge	$0.1115 per kWh
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

Monthly kWh Credit

The monthly energy credit (kWh) shall also be applied to the Company's following volumetric riders on the customer's monthly bill; Rider for Fuel and Purchased Energy Adjustment, Rider for Conservation Program Adjustment, Rider for Renewable Resources, Rider for Transmission Cost Recovery, Rider for Boswell Unit 4 Emission Reduction, and other Commission-approved volumetric riders on the customer's monthly bill.

Subscription Prices Calculation

The subscription prices above are calculated incorporating a $0.002 Solar Renewable Energy Credit (S-REC).

SERVICE CONDITIONS

1. To participate in the Community Solar Garden Pilot Program, a customer must submit an application to Minnesota Power's Renewable Programs Department. Each customer's subscription will be capped at 120 percent of the customer's average annual energy usage in the twelve months prior to the date of the customer's application to this program, but not to exceed 20 kW per Service Agreement.

2. Total participation of non-residential customers will be limited to no more than 50 percent of the total solar garden capacity during the initial offering.

3. Each customer participating in the Community Solar Garden Pilot Program will sign a 25-year contract which specifies the price the customer will pay for solar energy, aligned with the timeframe of the Company's power supply resource acquisition.
   a. Customers who choose Option 2 or Option 3 will have the ability to leave the program at any time. These customers may either have their subscriptions reassigned to another qualifying participant or relinquish their subscription to Minnesota Power.
   b. Customers who choose Option 1 will also have the opportunity to reassign or relinquish their subscription. Because customers on this option have made a significant upfront investment, if they cannot sell or transfer the subscription to another qualifying participant in a private transaction, Minnesota Power will purchase the subscription back from them at a predetermined amount that will decline by 4 percent per year from the original upfront payment amount.
   c. For cancelled subscriptions, Minnesota Power shall pay subscribers for the remaining kWh credits at the monthly average amount for the previous twelve months, plus any payment for S-RECs associated with the unused kWh credits.

4. Customers will not receive any cash payments or monetary credits in this program, with the exception of any payments resulting from subscription cancellation. Any excess energy shall be carried forward in the form of a kWh credit to the customer's subsequent bills for a period of five years. During this five-year period, the Company will evaluate what limits, if any, should be placed on the rolling over of energy credits. Banked credits are not transferable to other customers through subscription transfers.

RIDER FOR BACKUP GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75), and Municipal Pumping Service (Schedule 87) who contract for backup generation service of at least 50 kW for an initial period of ten years or more. Program participation will be limited to 10 MW total customer load.

RATE (Monthly)

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Customers taking firm service under this Rider will have an additional charge for backup generation applied to the customer maximum 15-minute demand as shown below:

A. The firm demand charge will be applied each month to the demand specified in customer's Backup Generation Service Agreement.

B. Redundant on-site backup generation capacity is available from Company if the added capacity is available to the Company under the existing terms of the tariff. Redundant backup generation service will be subject to an additional demand charges shown below applied to the capacity of the redundant generator. Any generator(s) installed in addition to generator(s) deemed appropriate by the Company to serve the customer's maximum 15-minute demand will be considered redundant under this tariff.

II. Customers taking interruptible service under this Rider will have an additional charge for backup generation applied to the agreed upon minimum contract firm demand level.

III. Firm demand charges are as follows:

A monthly per kW Firm Demand Charge shall be applied to the Customer maximum 15-minute demand, as defined in customer's Backup Generation Service Agreement.

SERVICE CONDITIONS

1. A customer receiving service under this Rider must enter into a contract that identifies the size of the generator specified and installed by the Company, the customer's expected annual maximum load, and the monthly firm demand charge. The company will have discretion as to the size and number of generators required to meet customer needs under this Rider.

2. If after five years the maximum customer 15-minute demand level falls below 75% of the contracted demand agreed upon in the customer's Backup Generation Service Agreement, the Company will determine whether to remove the generator and discontinue Backup Generation Service at that site or retain service and charge for this Rider based on the minimum contracted demand level as specified in the customer's Backup Generation Service Agreement. Generator size, use of the generator elsewhere, future customer demand, and special usage circumstances will be considered in making this decision.

3. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this Rider for all or only selected service feeds at that location. The Company may require the customer to pay in advance of

RIDER FOR BACKUP GENERATION SERVICE

installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise.

a. For firm service customers, backup generation service must be taken at a minimum of the entire load at each distribution service chosen. For purposes of this Rider, the customer demand will be the greatest rate at which electrical energy has been used for the distribution service feeds during any 15 minute period, for a minimum, of the preceding 24 billing months. For purposes of this Rider, the minimum demand determined by Company will consider anticipated load changes and/or unusual operation circumstances.

b. For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer’s firm load. For purposes of this Rider, the contract firm load will be the customer's contract firm load in effect at the time the customer enters into the Backup Generation Service Agreement with the Company.

4. The contract will have an initial minimum term of ten years. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

5. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Minnesota Public Utilities Commission. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

6. The Company will work with the customer to determine where to install the generator(s) and associated equipment. The facilities will comply with National Electric Code, National Electric Safety Code, Minnesota electric code and all applicable, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

7. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

8. The customer will supply the space for the generator(s) and a concrete pad as specified by the Company. The customer is responsible for clearing and grading the property and building the pad to specifications required by the Company.

9. The Company is responsible for installation of the generator and associated electrical interconnect. The customer is responsible for the cost of restoration of the property after the Company has completed installation where applicable.

10. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the customer will be required to make payment arrangements satisfactory to the Company for the cost of the facilities in excess of standard design.

RIDER FOR BACKUP GENERATION SERVICE

11. The customer will be required to make the Company equipment available and permit entry upon the property by Company or contracted personnel at all times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

12. The Company reserves the right to operate the generator to meet system load requirements. The Company will coordinate these operations to accommodate customer business requirements if possible.

13. The availability of service under this Rider may be limited at the discretion of the Company. Service under this Rider may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

14. Energy furnished under this Rider will not be resold by the Customer.

15. The customer may request that Company's on-site generation be operated during specific times. The Company will comply with Customer's request provided the additional hours of operation do not adversely impact any permits or other regulatory requirements. The customer shall pay the replacement cost of all fuel consumed during the test. The Company will pay all associated fuel costs of the generator for standard operation.

16. Company shall not be held liable for loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

17. If the customer chooses to end service under this Rider prior to the end of the current contract, the customer must pay 50% of the demand specified in customer's Backup Generation Service Agreement for the remaining term of the Backup Generation service obligation.

RIDER FOR BUSINESS EXPANSION INCENTIVE

APPLICATION

Applicable to any new or expanding commercial or industrial Customer taking service under General Service (Schedule 25), Large Light and Power Service (Schedule 75), or Large Power Service (Schedule 74) and which has at least 250 kW of new or expanding load. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

Customer must complete an application for service under the Rider for Business Expansion Incentive, and service is limited to customers whose application is approved by the Company. For existing customers, at least three months of Qualified Billing Demand must occur before service under this Rider may commence.

TYPE OF SERVICE

Service shall be taken at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer.

RATE

The provisions of the General Service, Large Light and Power, or Large Power Service Schedule shall apply, except monthly Demand Charges (excluding the Transmission Demand Charge) for customer's Qualified Billing Demand before the application of voltage discounts, shall be reduced as follows:

Large Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	30%	15%	5%	0%

General Service and Large Light and Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	50%	25%	15%	0%

For new or existing customers, Qualified Billing Demand is the new load of 250 kW or greater at a single delivery point. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. The demand charge reduction shall not apply during any month in which the Qualified Billing Demand is below 250 kW, unless as a consequence of documented new conservation or load control by the customer.

RIDER FOR BUSINESS DEVELOPMENT INCENTIVE

This Rider is available for new load that is associated with initial permanent service. To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:

1. Business has not been conducted at the premises for at least three monthly billing periods prior to application; or

2. The predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale; or

3. Customer's activities are largely or entirely different in nature from that of the previous customer.

EXISTING CUSTOMER QUALIFICATIONS

Existing customers who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company shall review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 250 kW at one delivery point, the customer will be eligible thereafter to receive service under this Rider. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. If a customer's activities are very similar to the customer's previous activities, then the customer is considered to be an existing customer whether or not the owner(s), operator(s), or manager(s) are substantially different.

ENERGY EFFICIENCY

The Company is required to conduct an energy audit for all customers taking service under this Rider, and inform the customer of the conservation programs available.

TERMS AND CONDITIONS

1. This Rider contemplates that this service shall utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required, which are not supported by this Rider.

2. The minimum discount under this Rider shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the Rider is in effect.

RIDER FOR BUSINESS DEVELOPMENT INCENTIVE

3. The Company shall execute an Electric Service Agreement (ESA), having a minimum term of six (6) years with a minimum cancellation provision of one (1) year. The ESA shall state the increased or new load level of the customer, and the effective date of service under this Rider shall be set forth in the ESA.

ELECTRIC SERVICE AGREEMENTS

1. Every ESA and every amendment or modification of an ESA shall be approved by the Minnesota Public Utilities Commission ("Commission").

2. Every new or amended ESA shall be filed with the Commission within 30 days after signing the agreement with the Customer.

3. Every ESA filing shall include the incremental revenue and the incremental costs associated with the new ESA.

4. If no party objects to the ESA within 30 days of the filing date, the ESA is deemed approved.

RIDER FOR CITY OF UPSALA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Upsala, except bills for electric service to property owned by the City of Upsala.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Upsala Franchise Fee assessment in the amount of:

$5.00 per month for each electric residential service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Upsala Franchise Fee assessment collected will be passed along to the City of Upsala.

RIDER FOR 2017 FEDERAL TAX CUT REFUND

APPLICATION

Applicable to electric service under all Retail Rate Schedules (and including all applicable Riders thereto) except that this Rider shall not be applicable to service under Company's Rider for Large Power Interruptible Service, Rider for Large Power Incremental Production Service or Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is not applicable to billings under the Rider for Conservation Program Adjustment, Rider for Renewable Resources, Rider for Transmission Cost Recovery, Rider for Customer Affordability of Residential Electricity (CARE), Rider for Boswell Unit 4 Emission Reduction Rider for Voluntary Renewable Energy, and Pilot Rider for Community Solar Garden.

ADJUSTMENT

There shall be applied to Customer's monthly bill an Excess Accumulated Deferred Income Tax (Excess ADIT) refund factor applicable to all charges for service taken under Company's standard rate schedules (except as described above):

All applicable Retail Rate Customers: -1.5259% refund factor

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74, having a minimum contract term of at least the duration of the respective demand response product, and subject to the Conditions below.

DEFINITIONS

Demand Response Billing Demand: Capacity volume associated with the Rider for Large Power Demand Response Products A and C that will receive Demand Charge Credits on a monthly basis, as specified herein.

Demand Response Contract Demand: The aggregate of Customer's accredited capacity of Products A and C under this Rider.

Firm Service Level or Targeted Demand Reduction Level: Customer's targeted demand reduction threshold that is specified when customer registers for Products A and C.

Emergency Curtailment: Requirement for participating Customers to physically reduce load to their Firm Service Level or Targeted Demand Reduction Level.

LARGE POWER DEMAND RESPONSE PRODUCTS AND CONDITIONS

There are two optional Demand Response products available to Customers. The characteristics and conditions for each product are as follows:

Large Power Demand Response Product A - Short-Term Emergency Capacity
Product A is a one-year emergency-only capacity product. A minimum one-year Demand Response commitment and one-year term remaining on Customer's Electric Service Agreement at time of selection is required for this product. Product A includes a Demand Charge Credit as detailed in the Rate section below. The Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events.

Short-Term Emergency Capacity must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur.

Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that as required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

Large Power Demand Response Product C – Market Surplus Service

Contract periods of between three and six years are available, provided that Customer's Electric Service Agreement duration at time of bidding is at least as long as the Market Surplus Service contract, and provided that neither the Customer nor the Company has served an Electric Service Agreement cancelation notice. Product C includes a Demand Charge Credit as detailed in the Rate section below. The Company will facilitate identification of options for a customer's excess demand response capacity that doesn't fit into Large Power Demand Response Product A.

RATE MODIFICATIONS

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard Large Power rate schedule:

Demand Response Product A - Short-Term Emergency Capacity

Demand Charge Credit:

For each month that Short-Term Emergency Capacity is provided, the Customer shall receive a per kW Demand Charge Credit based on an annual market price representative of market conditions as determined by the Company. Such credit shall be applied to the demand charges billed under Schedule 74. Customer will be notified of the annual credit amount by the preceding November for the following Midcontinent Independent System Operator (MISO) planning year.

Demand Response Product C- Market Surplus Service

Demand Charge Credit:

For each month that Market Surplus Service is provided and Minnesota Power has identified an option for customer's excess demand response capacity that results in revenue for the Company, the Customer shall receive a per kW Demand Charge Credit. Such credit shall be determined by the company and applied to Customer's demand charges billed under Schedule 74.

DETERMINATION OF DEMAND RESPONSE BILLING DEMAND (Monthly)

Demand Response Billing Demand shall be calculated as follows:

The lesser of: (1) the Demand Response Contract Demand or (2) Customer's nominated demand under Schedule 74 plus, if applicable, Maximum Replacement Amount less Firm Service Level.

Any reduction in the Demand Response Billing Demand from the Demand Response Contract Demand will first reduce Product A and then Product C.

The Customer's monthly Schedule 74 Billing Demand shall be calculated in accordance with Schedule 74.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED CURTAILMENT

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the Firm Service Level or Targeted Demand Reduction Level.

In the event that the Customer fails to follow an Emergency Curtailment request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Emergency Curtailment conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

ADDITIONAL SERVICE CONDITIONS

1. The duration and frequency of curtailments shall be at the sole discretion of the Company and follow the product conditions as stated above.

2. The Customer must provide, at its expense, a means of curtailing its demand response load upon receiving a command or signal from the Company. The Company reserves the right to inspect and approve the installation.

3. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

4. Company intends to accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with Module E Tariff and Business Practices Manual for Resource Adequacy. Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the party's shall in good faith determine the most appropriate substitute accrediting and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either party's rights or obligations under the Electric Service Agreement. Any changes would be subject to regulatory approval.

PILOT RIDER FOR REMOTE SERVICE RECONNECTION

APPLICATION

Applicable on a voluntary basis to customers taking service under the Residential Service Schedule 20 or 22, Dual Fuel Interruptible Electric Service Schedule 21, Controlled Access Electric Service Schedule 24, or Residential Electric Vehicle Service Schedule 28.

In order to be eligible for this Pilot Rider, Customer must have Advanced Metering Infrastructure (AMI) with remote reconnect capability, and shall have been disconnected following procedures specified in Company's Service Regulations, Section VI, page 3.4, Regulation 19.

RATE MODIFICATION

Remote Service Reconnection is available any time of the day, all year and the Fee shall be as follows:

Remote Service Reconnection Fee: Waive

SERVICE CONDITIONS

1. Customers may choose to be reconnected using remote AMI capability and shall be reconnected for the Remote Service Reconnection Fee specified above after they have met the payment requirement as stipulated in the Company's Service Regulations, Section VI, page 3.5, Regulation 20. This Remote Service Reconnection Fee replaces the Service Reconnection Fee specified in regulation 20.A.

2. Customers who are remotely reconnected will be walked through the process on the phone by a Company representative during the reconnection process to ensure that the connection has taken place and is completed safely.

3. Customers without existing AMI equipment may request participation in this Pilot Rider. The Company will install and commission the equipment at the Customer's residence prior to making the Pilot Rider available.

RIDER FOR CITY OF PEQUOT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Pequot Lakes, except bills for electric service to property owned by the City of Pequot Lakes.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Pequot Lakes Franchise Fee assessment in the amount of:

$1.00 per month for each electric residential account; and
$1.00 per month for each commercial, industrial or other electric service account.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Pequot Lakes Franchise Fee assessment collected will be passed along to the City of Pequot Lakes.

RIDER FOR RENEWABLE RESOURCES-SOLAR FACTOR ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard (SES) obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f). During the 2013 Minnesota legislative session, Minnesota Statutes Section 216B.1691, the statute establishing Minnesota's Renewable Standard, was amended to include an additional SES under Minnesota Statutes Section 216B.1691, Subd. 2f. Included in Minnesota Statutes, Section 216B.1691, subd. 2f is a provision exempting retail electric sales to certain customers, namely large iron mining and paper production businesses, from the total retail electric sales calculation of a public utility. Per subdivision 2f(f), exempted customers are:

(1) an iron mining extraction and processing facility, including a scram mining facility as defined in Minnesota Rules, part 6130.0100, subpart 16; or
(2) a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer.

Exempted customers cannot be charged for any costs specific to satisfying the Solar Energy Standard.

The solar capacity benefit charge associated with the Camp Ripley Solar Project is applied to exempt customers as they share in these benefits.

ADJUSTMENT

Customers' monthly bills will be adjusted in accordance with each customer's status per Minnesota Statutes, Section 216B.1691, Subd. 2f. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

	SES-Paying Customers	SES-Exempt Customers
Residential Customers	0.107¢ per kWh for all kWh	
General Service Customers	0.119¢ per kWh for all kWh	0.054¢ per kWh for all kWh

Large Light & Power Customers	0.115¢ per kWh for all kWh	0.004¢ per kWh for all kWh
Large Power Customers		0.021¢ per kWh for all kWh
Lighting Customers	0.453¢ per kWh for all kWh	

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

APPLICATION

Applicable to Customers taking service under: Residential Service Schedule 20 (General), Schedule 22 (Space Heating), and Schedule 23 (Seasonal) who do not want advanced metering infrastructure ("AMI") at their residence ("Opt-Out Customers"). All provisions of the Residential Service Schedule and the Company's Electric Service Regulations shall apply to the service under this Rider except as noted below.

DESCRIPTION

There shall be applied to an Opt-Out Customer's monthly bill a recurring monthly fee after enrollment. The applicable fee for participating in the AMI Opt-Out will be shown as a separate line item on the monthly bill as follows:

AMI Opt-Out Charge $20.00 per month

The monthly charge will be applied following the meter exchange. Where a meter exchange is not required, the charge will be applied following the AMI Opt-Out election or action by the Opt-Out Customer, as described in the Service Conditions.

SERVICE CONDITIONS

1. The Company shall have the right to refuse to provide AMI Opt-Out service in any of the following circumstances:
    a) If such a service creates a safety hazard to the Customer or their premises, the public, or the Company's personnel or facilities.
    b) If a Customer does not allow the Company's employees access to the meter at the Customer's premises.
    c) If the Customer has a history of meter tampering.

2. Opt-Out Provisions:
    a) Opt-Out Election: A Customer must affirmatively elect to opt-out of having electric consumption metered through AMI to obtain service under this Rider. Customers shall default to AMI absent such an election. Customers who do not provide reasonable access to their meter or affirmatively prevent the installation of AMI shall be deemed to have elected this Opt-Out Rider.
    b) Frequency of Election: A Customer may only enroll in this AMI Opt-Out Rider once per twelve-month period at the same residence.
    c) Opt-In Election: At any time, Opt-Out Customers may opt back into electric service with AMI.
    d) Local governments and entities such as condominiums and other multi-unit dwellings are not allowed to exercise the Opt-Out option on behalf of individually metered residents.

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

3. Metering Equipment: A non-communicating meter will be used to provide electric service for Customers who elect this option.

4. Customers enrolled in interruptible electric service, controlled access, time-of-day, or other service requiring AMI will be notified that the Customer must discontinue participation in the service offering in order to participate in this Opt-Out option.

5. Estimated Meter Reading: Opt-Out Customers may receive bills based on estimated meter reads if circumstances prevent reading a meter in a given month.

6. Billing: Customers will be billed for charges incurred for electric consumption under the applicable Residential Service Schedule, plus the Monthly Charge described in this AMI Opt-Out Rider.

RIDER FOR RESIDENTIAL TIME-OF-DAY SERVICE

APPLICATION

Applicable to customers taking service under Residential Service Schedule 20 (General) or Schedule 22 (Space Heating), for single-family dwellings. All provisions of the Residential Service Schedule shall apply to the Residential Time-Of-Day service under this Rider except as noted below.

Customers taking service under this Rider may not also take service under the Pilot Rider for Community Solar Garden Subscription, nor under the Rider for Parallel Generation.

RATE MODIFICATION

Customers will be billed at the Residential Service rate, plus the following Energy Charge Adjustments shall apply:

	Energy Charge Adjustment
All On-Peak kWh	3.667¢/kWh
All Off-Peak kWh	-0.239¢/kWh
All Super Off-Peak kWh	-2.677¢/kWh

SERVICE CONDITIONS

On-Peak, Off-Peak, and Super Off-Peak Period Defined: The On-Peak Periods shall be defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. The Super Off-Peak Period shall be defined as 11:00 p.m. to 5 a.m., inclusive. The Off-Peak Periods shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

SPECIAL RULES

1. Any Customer choosing to be served on this rate tariff thereby waives all rights to any billing adjustment arising from any claim that the bill for the Customer's services would be cheaper on any alternative rate schedule for any period of time.

PRIVACY PROVISION

The Company follows its standard operational privacy guidelines and practices for all customers, including those participating under this Service Schedule. The Company complies with the State and Federal laws and regulations governing utility customer data

RIDER FOR RESIDENTIAL TIME-OF-DAY SERVICE

use such as the Federal Power Act, the Minnesota Public Utilities Act, and the Minnesota State Statutes including Chapters 47 and 248B.

The Company routinely collects data about and from its Customers through various sources as part of the normal course of providing services. Customer personal information, account and usage details, billing information, and program participation details are secured and retained in internal and online databases in accordance with the Company's standard operational guidelines which maintain administrative, technical, and physical safeguards to protect the privacy and security of the information. These safeguards include but are not limited to encryption, password protection, and secured files and buildings.

Energy Consumption Data:

Energy consumption and tariff data will be collected during the participation period. This data includes:

a. Date and hour of each day, with time zone;
b. Hourly interval meter usage data for 0-12 months prior to commencement of the Tariff (depending upon the date of meter installation relative to start of Tariff) and during the participation period;
c. Hourly weather data from the nearest weather station for 12 months prior to commencement of the Tariff and during the participation period;
d. Tariff sheet reference (i.e., which tariff sheet(s) each customer was on and the date range that the customer was on that tariff sheet for the 12 months prior to the commencement of the Tariff);
e. Start date of billing cycle;
f. Monthly electricity bill (i.e., $ amount) for 12 months prior to commencement of the Tariff; and
g. Electricity usage from the monthly bill for 12 months prior to commencement of the Tariff and during the participation period.

RIDER FOR CITY OF SANDSTONE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Sandstone, except bills for electric service to property owned by the City of Sandstone.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Sandstone Franchise Fee assessment in the amount of:

$2.59 per month for each electric residential service agreement; and
$2.59 per month for each commercial, industrial or other electric service agreement.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Sandstone Franchise Fee assessment collected will be passed along to the City of Sandstone.

DEFINITIONS OF CLASSES OF CUSTOMERS

RESIDENTIAL

A customer using electric energy supplied for residential (household) purposes.

RESIDENTIAL WITH TOTAL ELECTRIC SPACE HEATING

A subdivision of the Residential classification that includes those customers who use electricity as the source of space heating throughout the entire premises from permanently installed electric heating equipment.

COMMERCIAL

A customer using service at a location where the purchaser is engaged in selling, warehousing, or distributing a commodity, in some business activity, in rendering professional service, or in some form of social activity. In borderline cases where the nature of the customers' activities does not differentiate clearly between Commercial and Industrial, the service is classified as Commercial.

INDUSTRIAL

A customer using service at a location where the purchaser is engaged in an industrial activity, such as the operation of factories, mills, machine shops, mines, oil wells, refineries, pumping plants, cleaning and dyeing works, creameries, canning establishments, stockyards, etc., that is, in extractive, fabricating or processing activities.

GOVERNMENTAL

Municipalities and all divisions or agencies of state or federal governments.

RESIDENTIAL SERVICE RULES

1. Equipment which is capable of disturbing service to neighboring customers and/or motors operating with phase converters totaling more than 20 horsepower shall be separately metered on the applicable General Service schedule. Equipment capable of disturbing service to neighboring customers may include, but is not limited to, the following: welders, motors not conforming to Company's starting current limits, cooking and heating equipment of a design not approved by the Company.

2. In buildings having two or more apartments (as defined below), each apartment shall be considered a single-family dwelling. For each apartment building or portion of a building used for apartments that is arranged to permit the consumption of electricity by each apartment to be individually metered, Company will install meters to measure the consumption of electricity and will separately bill each individual apartment on the applicable rate schedule. However, where a landlord advises the Company that service applies to a single-metered apartment the billing shall be to the landlord and in accordance with Minn. Stat. 504B.215. In all other cases, the billing shall be computed as though each apartment used an equal portion of the total service and were independently billed. Service shall not be submetered or resold.

3. An apartment is defined as a portion of a building consisting of two or more rooms completely equipped for living purposes. Janitor's quarters shall be classed as an apartment.

4. A customer occupying a building or apartment for residential and commercial purposes jointly may combine his residential and commercial use on the applicable General Service schedule but not under the Residential Service schedule.

5. The public portion of apartment buildings, such as lobbies, halls, laundry rooms, boiler rooms, etc., and the power equipment, such as coal stokers, oil burners, air conditioners, elevators, etc., shall be served on the applicable General Service schedule.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

PURPOSE AND CONTENTS

These Service Regulations govern the supplying and taking of electric service. The regulations are designed to provide each Customer the greatest practicable latitude in the use of service consistent with reliable, economical and safe service to all Customers.

These Service Regulations, together with Extension Rules and Rate Schedules, are on file in the Company's various offices, and copies are obtainable by any Customer upon request by telephone, by mail, or www.mnpower.com.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

SECTION I - DEFINITIONS

The following terms when used in these Service Regulations, in Rate Schedules and in Service Agreements, shall, unless otherwise indicated, have the meanings given below:

1. **Customer:** Any individual(s), partnership, association, firm, public or private corporation or governmental agency having Company's electric service at any specified location.

2. **Company:** Minnesota Power.

3. **Electric Service:** The supplying of electric power and energy, or its availability, irrespective of whether any electric power and energy is actually used. Supplying of service by Company consists of the maintaining by it, at the point of delivery, of approximately the agreed voltage and frequency by means of facilities adequate for carrying Customer's contracted load.

4. **Point of Delivery:** The end of Company's service drop, or the point where Company's wires are joined to Customer's service entrance conductors or apparatus, unless otherwise specified in Customer's Service Agreement.

5. **Customer's Installation:** In general, all wiring, appliances and apparatus of any kind or nature on Customer's side of the point of delivery (except Company's meter installation), useful in connection with Customer's ability to take electric service.

6. **Service Drop:** The wires, owned by Company, connecting Company's distribution mains to Customer's service entrance conductors.

7. **Service Entrance Conductors:** The wires provided by the Customer extending from Customer's main line switch or center at which circuits originate, to the terminal of the Company's service drop.

8. **Month:** An interval of approximately thirty days between successive meter reading dates, except when the calendar month is specified.

9. **Service Agreement:** The agreement or contract between Company and Customer pursuant to which service is supplied and taken.

10. **Notice:** Unless otherwise specified, a written notification delivered personally or mailed by one party to the other at such other party's last known address, the period of notice being computed from the date of such personal delivery or mailing.

11. **Meter:** The meter or meters, together with auxiliary devices, if any, constituting the complete installation needed to measure and report the power and energy supplied to any Customer at a single point of delivery.

12. **Customer Extension:** Any branch from, or continuation of, an existing line to the point of delivery to Customer, including increases in capacity of any of Company's existing facilities, or the changing of any line to meet the Customer's requirements, and including all transformers, service drops and meters.

SECTION II - SERVICE AGREEMENTS

13. **Form and Execution of Service Agreements:** Each application for service normally is made on Company's standard form of application, which, when properly executed by Customer and Company, becomes binding and along with the applicable Rate Schedules, Rules and Regulations, is termed a Service Agreement. Any Service Agreement referred to herein is subject to amendment or change by Company. Any such amendment or change to a Service Agreement may be subject to acceptance or approval by any regulatory body having jurisdiction thereof and upon acceptance or approval will automatically apply to any executed Service Agreement.

If for any reason an application is not signed by the Customer, the giving of service by the Company and the accepting of such service by all Customers receiving service shall impose the same obligation on each as if a Service Agreement had been executed.

14. **Contract Period of Service Agreements:** The contract period shall be as indicated in the applicable Rate Schedule, unless otherwise provided for in the Service Agreement.

15. **Renewal and Termination of Service Agreements:** Renewals shall be as provided for in the Service Agreement. Unless otherwise provided in the Service Agreement or Rate Schedule, Customer may terminate service at any time by notifying Company not less than three days prior to the date termination is desired. Customer will be held responsible for all service supplied to vacated premises until such notice has been received by Company. Notification may be made by writing, by telephone, mail or by visiting the Company's website at www.mnpower.com.

When the contract period of a Service Agreement is extended, the demand previously established by Customer is considered as having been established under the extended contract period.

When a new Service Agreement is entered into, the demand previously established by Customer is considered as having been established under the contract period of the new Service Agreement except that, when the contract demand under the new Service Agreement is less than 60% of the highest actual demand established in the previous contract year, the Company will waive the above requirement.

16. **Company's Right to Cancel Service Agreement or to Suspend Service:** Company, in addition to all other legal remedies, may terminate the Service Agreement, or suspend delivery of service, for any default or breach of the Service Agreement by the Customer,

but no such termination or suspension will be made by Company without five (5) days written notice, excluding Sundays and legal holidays, to Customer, stating in what particular the Service Agreement has been violated, except in cases of unlawful or unauthorized use of service by Customer, or dangerous leakage or short circuit on Customer's side of the point of delivery, or in case of utilization by Customer of service in such manner as to cause danger to persons or property. Failure of Company at any time to either suspend delivery of service or to terminate the Service Agreement, or to resort to any other legal remedy, or its adoption of either one or the other of such alternatives, shall not affect Company's right to resort to any of such remedies for the same or any future default or breach by Customer.

17. **Successors and Assigns:** Service Agreements inure to the benefit of and are binding upon the respective heirs, legal representatives, successors and assigns of the parties thereto; but no assignment by Customer shall be binding upon Company until accepted in writing by the latter.

SECTION III - SUPPLY AND TAKING OF SERVICE

18. **Supplying of Service:** Service is supplied only under and pursuant to these Service Regulations and the applicable Rate Schedule, Riders, and Regulatory Rules. Service is supplied under a given Rate Schedule only at such points of delivery as are adjacent to facilities of Company adequate and suitable, as to capacity and voltage, for the service desired.

Service will be subject to disconnection and deposit requirements as provided by rules of the Minnesota Public Utilities Commission and other applicable law, if, at the time of application for service, the Customer is indebted to the Company for service previously supplied at the same or another address.

19**. Disconnection of Service:**

A. With Notice - Service may be disconnected with notice for any reason under Minn. Rules Part 7820.1000 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

B. Without Notice - Service may be disconnected without notice for any reason under Minn. Rules Part 7820.1100 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

20**. Reconnection of Service:** Company shall reconnect service following disconnection for non-payment:

- After all past due accounts, deposits and reconnection fees, where applicable, shall have been paid or
- Under a payment agreement for all past due accounts, deposits and reconnection fees, where applicable. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or

continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected.

A. The Service Reconnection Fee shall be as follows:
   i. $20.00 between the hours of 8:00 AM and 4:30 PM Monday through Friday.
   ii. $100.00 after 4:30 PM, before 8:00 AM and on Saturdays, Sundays and legal holidays.

B. Where service has been disconnected under Minn. Rules Part 7820.1100.B., a reconnection fee will not be required.

C. Following disconnection under Minn. Rules 7820.1100.A., reconnection will occur only after Company has received payment from Customer of the following:
   i. Power and energy not recorded on the meter at the appropriate rate, the amount of which may be estimated by Company based on the best available data.
   ii. All expenses incurred by Company due to any such unauthorized act or acts.

21. **Service Relock Penalty:**

A. Company shall assess a Service Relock Penalty of $100.00 where the Company has previously disconnected service and is required to subsequently return to relock or disconnect the service after it was connected by a Customer without Company authorization.

B. Company shall assess a penalty for all expenses incurred if additional disconnection of service is required at Customer premises.

C. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

22. **Continuity of Service:** Company will endeavor to provide continuous service but does not guarantee a constant supply of electric energy and shall not be liable to Customer for damages occasioned by interruption, except as provided by law. The Company shall not be liable for any loss of profits, special, or consequential damages resulting from the use of service or any interruption or disturbance of service.

In the event of power shortage any curtailment among Customers shall be made as nearly as practical pro rata without liability on the part of Company to any Customer affected.

If any part of service furnished by Company is employed for purpose of pumping water, Company assumes no obligation to maintain an adequate supply for fire protection, or any other purpose, whatsoever, and such use shall not subject Company to any liability to any party for damages to person or property due to failure of water supply resulting from an interruption or deficiency of electric service from whatsoever cause the same may arise.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

23. **Suspension of Service for Repairs and Changes:** When necessary to make repairs to or changes in its lines or system, Company may, without incurring any liability therefore, suspend service for such periods as may be necessary, and in such manner as to minimize inconvenience to Customer.

24. **Use of Service:** Service is for Customer's use only. Company permits redistribution and submetering only where allowed by law. The electric service equipment and associated building wiring of buildings shall be arranged by the owner to permit individual metering of the electrical consumption of each building and occupancy unit to comply with Minn. Stat. 504B.161 and any law amendatory thereto. If desired by the owner, the Company will install and maintain necessary individual Company meters to measure consumption and render bills on the applicable Rate Schedules to each Customer and separately occupied building and occupancy unit.

In no case may Customer, except with the written consent of Company, extend or connect an installation to lines across or under a street, alley, lane, court or avenue or other public or private space in order to obtain service for adjacent property through one meter even though such adjacent property be owned by Customer. Such consent may be given when such adjacent properties are operated as one integral unit under the same name and for carrying on parts of the same business. In case of unauthorized remetering, sale or extension of service to another person, Company, after five (5) days written notice excluding Sundays and legal holidays, may discontinue the supplying of service to Customer until such unauthorized act is discontinued and full payment is made for all service supplied or used, billed on proper classification and Rate Schedule, and reimbursement in full made to Company for all extra expenses incurred, including expenses for clerical work, testing and inspections.

25. **Customer's Responsibility:** Customer assumes all responsibility on Customer's side of the point of delivery for the service supplied or taken, as well as for the electrical installation, appliances and apparatus used in connection therewith, and shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from such service or the use thereof on Customer's side of the point of delivery.

26. **Right-of-Way:** Customer shall, without compensation, make or procure satisfactory conveyance to Company of right-of-way for Company's lines necessary and incidental to the furnishing of service to Customer and for continuing or extending said lines over, under, across or through the property owned or controlled by Customer in a manner deemed appropriate by the Company (including facility maintenance and vegetation management rights).

27. **Access to Premises:** Company personnel may enter Customer's premises only as authorized by applicable law and regulations. Failure of Customer to provide Company reasonable access may result in disconnection of service under Minn. Rules Part 7820.1000(E).

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

28. **Location of Point of Attachment:** Customer's Point of Attachment is to be located at a point readily accessible to Company's distribution mains. Customer shall install and maintain a point of attachment for Company's service drop. Said point of attachment shall be of sufficient mechanical strength to support the wind and ice loaded weight of the service drop and shall be located as determined by the Company.

SECTION IV - CUSTOMER'S INSTALLATION

29. **Nature and Use of Installation:** All of Customer's wires, apparatus and equipment shall be selected with the view to obtaining safety, good efficiency, good voltage regulation and the highest practicable power factor and shall be installed in accordance with standard practices. Customer shall install and maintain, on Customer's side of point of delivery, suitable protective equipment as may be required by the Company for the protection of its service to other customers and may not employ or utilize any equipment, appliance or device so as to affect adversely Company's service to Customer or to others. The Company's failure to require such equipment shall not operate to relieve Customer from the obligation to utilize and comply with standard practices. Company may require auto starters or other suitable starting devices for motors above 5 horsepower. When polyphase service is supplied by Company, Customer shall control the use thereof so that the load at the point of delivery will be maintained in reasonable electrical balance between the phases.

Installations of neon, fluorescent, mercury vapor lamps or tubes, or other types of gaseous tube lamps, or other devices having low power factor characteristics, should be equipped with corrective apparatus to increase the power factor of each unit or separately controlled group of units to not less than approximately 90% lagging.

30. **Inspection by Company:** Company retains the right, but does not assume the duty, to inspect Customer's installation at any time and will refuse to commence or to continue service whenever it does not consider such installation to be in good operating condition, but Company does not in any event assume any responsibility whatever in connection with such matters.

31. **Changes in Installations:** As Company's service drops, transformers, meters, and other facilities used in supplying service to Customer have a definite limited capacity, Customer shall give notice to Company, and obtain Company's consent, before making any material changes or increases in Customer's installation. Company as promptly as possible after receipt of such notice will give its approval to the proposed change or increase, or will advise Customer upon what conditions service can be supplied for such change or increase. Failure to secure Company's approval shall make Customer liable for any damage to Company's facilities.

SECTION V - COMPANY'S INSTALLATION

32. **Installation and Maintenance:** Except as otherwise provided in these Service Regulations, in Service Agreements or Rate Schedules, Company will install and maintain its lines

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

and equipment on its side of the point of delivery, but shall not be required to install or maintain any lines or equipment, except meters, on Customer's side of the point of delivery. Only Company's agents are authorized to connect Company's service drop to Customer's service entrance conductors and to connect Company's meters.

A. Electrical Permit: The Company is prohibited from connecting its service drop to Customer's service entrance conductors until permitted by the governmental authority having jurisdiction.

B. Standard Connection: The ordinary method of connection between Company's distribution mains and Customer's service entrance conductors will be by overhead wires. If Customer desires to have connection made in any other manner, special arrangements will be made between Customer and Company by which the connection will be made and maintained at Customer's expense.

C. Suitable Space: The Customer shall provide at no cost to Company a suitable room or space for Company's transformers and equipment specifically used in providing service to Customer when such room or space is deemed necessary by Company.

33. **Protection by Customer:** Customer shall protect Company's wiring and apparatus on Customer's premises and shall permit no one except Company's agents or persons authorized by law to inspect or handle same. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

Company shall not be responsible to Customer or any other party because of any damage resulting from such installations which are not readily subject to inspection from the ground and the exterior of the premises, or from the meter location, unless Customer shall have notified Company of a condition which, in the reasonable opinion of the Customer, requires attention and the Company shall have had a reasonable time within which to inspect and, if necessary, repair the same.

34. **Customer Extensions:** The Company, at its own expense, makes extensions where the revenue therefrom is sufficient, in Company's opinion, to justify the necessary expenditure.

Where the Company cannot be assured that the business offered is of sufficient duration, where unusual expenditures are necessary to supply service because of location, size or character of installation, or where area requirements of regulatory bodies may control, the Customer or Customers shall make arrangements satisfactory to Company dependent upon the particular conditions of each situation.

35. **Alteration of Facilities:** Company will, at its discretion, alter, relocate, convert to underground, or remove Company's facilities as may be requested in writing by Customer. Customer shall pay Company for all costs, except as limited below, associated with such

alteration, relocation, conversion to underground, or removal including any new facilities required to provide service after the alteration, relocation, conversion, or removal.

Customers requesting the alteration, relocation, conversion, or removal shall pay the estimated cost for the change, less salvage, of the facilities required to effect such change prior to Company committing funds for the work. Where the actual cost is different from the estimated cost upon which the advance payment was based, as determined upon completion of the requested alteration, relocation, conversion, or removal, Company will refund any excess payment made by Customer or render a bill for any additional amount due. However, where Company's estimated cost is less than $5,000.00, and actual cost exceeds such estimate, the additional amount due by Customer shall not exceed 15 percent of the estimate, regardless of the amount of actual cost.

SECTION VI - METERING

36. **Installation:** Company shall furnish and install the necessary meter or meters, and Customer shall provide and maintain a location, free of expense and satisfactory to Company, all in accordance with Company's Metering Standards.

37. **Evidence of Consumption:** Unless proven to be inaccurate, the registration of Company's meter shall be accepted and received at all times and places as prima facie evidence of the amount of power and energy taken by Customer.

38. **Tests:** Company tests its meters and maintains their accuracy of registration in accordance with good practice. On request of Customer, Company will make a special test which will be done at the expense of the Company. If the Customer requests another test before the expiration of a twelve-month period, the Customer shall bear the cost of the test if the meter is found to be in error by less than 2%, fast or slow. The average registration accuracy of a meter is taken as the mean of full load (100% of rated load) accuracy, and light load (5-10% of rated load) accuracy. At Company's discretion, tests may be made under average load conditions.

SECTION VII - PARALLEL GENERATION

39. **Design:** Customer's electric generating equipment shall be designed (1) to operate in synchronization with Company's system and (2) to automatically disconnect the facility from Company's system in the event Company's system becomes de-energized unless by mutual agreement between the Customer and Company. All synchronizing and protective devices to accomplish this mode of operation shall be provided and maintained by Customer.

40. **Disconnection:** Customer shall provide and maintain a manual, lockable disconnect switch providing a visible open and capable of isolating the Customer's generator from the Company's electrical system. This disconnect switch shall be readily accessible to Company personnel at all times, shall include a provision for padlocking it in the open position, and shall meet all other reasonable requirements established by Company.

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41. **Customer Responsibility:** Customer shall pay for the cost of rebuilding and/or modifying Company facilities to provide adequate capacity for the parallel generation system and adequate protection for the Company's electrical system.

Customer shall be subject to the State of Minnesota Distributed Energy Resources Interconnection Process and Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements or the most recent version of Minnesota's interconnection standards. Copies of such standards shall be made available to Customer upon request and are available at www.mnpower.com.

SECTION VIII - BILLING

42. **Billing Periods:** Bills ordinarily are rendered regularly at monthly intervals, but may be rendered more or less frequently at Company's option. Non-receipt of bills by Customer does not release or diminish the obligation of Customer with respect to payment thereof.

43. **Separate Billing for Each Point of Delivery:** At each point of delivery the use of service is metered separately for each Customer served. Whenever for any reason Company furnishes two or more meter installations for a single Customer, or supplies service under a Rate Schedule which does not require a meter, each point of metering and/or point of delivery where no meter is required is considered as a separate service. A separate Service Agreement is required, and bills are separately calculated, for each such separate service, except where Company may, under special circumstances, waive this requirement.

44. **Adjustment for Inaccurate Meter Registration:** Meter too fast or too slow: In the event that any routine or special test of a Company meter discloses its average accuracy of registration to be in error by more than 2%, fast or slow, Company will refund the overcharge for a fast meter or charge for electricity consumed, but not included in the bills previously rendered for a slow meter. The refund or charge for both fast and slow meters will be based on corrected meter readings for a period equal to one-half the time elapsed since the last previous test but not to exceed six (6) months, unless it can be established that the error was due to some cause, the date of which can be fixed with reasonable certainty, in which case the refund or charge will be computed to that date, but in no event for a period longer than one (1) year.

Whenever any bill or bills have been adjusted or corrected as provided above, the Company will refund to existing Customer any amount due when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due when the amount due exceeds two ($2.00) dollars or Company will bill Customer for any amount owed when the amount owed exceeds ten ($10.00) dollars, as the case may be.

Meter fails to register or registers intermittently: When the average error cannot be determined by test because the meter is not found to register or is found to register intermittently, the Company may charge for an estimated amount of electricity used, which

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shall be calculated by averaging the amounts registered over corresponding periods in previous years or in the absence of such information, over similar periods of known accurate measurement preceding or subsequent thereto, but in no event shall such charge be for a period longer than one year.

If a Customer has called to the Company's attention doubts as to the meter's accuracy and the Company has failed within a reasonable time to check it, there shall be no back billing for the period between the date of the Customer's notification and the date the meter was checked.

45. **Late Payment Charge:** Company shall assess a Late Payment Charge of 1.5% per monthly billing period, on that portion of a retail Customer's account representing charges for Company service(s) past due, if the unpaid balance exceeds $10.00. All late payments received will be credited against the oldest outstanding account balance before the application of any Late Payment Charge. The unpaid Company account balance for a Customer under the Budget Billing Plan or another Company approved payment plan shall mean that the Company budget arrears balance and not the accumulated actual Company balance will be subject to a Late Payment Charge. No Late Payment Charge will be charged on the portion of the Company balance in dispute while dispute procedures are underway. A Late Payment Charge may be retroactively charged on the settled amount after dispute procedures are completed. At Company's discretion, any Late Payment Charge, or portion thereof, may be waived provided such waiver is consistent with the Minnesota Public Utilities Act.

A. **Residential Customer**: A Late Payment Charge shall be added to any Company account for which payment is not received and credited by Company within fifteen (15) days from the current billing date, plus ten (10) days of grace period, or a total of twenty-five (25) days. Residential customer who qualifies for assistance under the Low Income Home Energy Assistance Program (LIHEAP) may request waiver of the Late Payment Charge on the "current bill" portion of each monthly bill. Self-qualification using LIHEAP income guidelines will be permitted for Senior Citizens at age 62 or older. Efforts will be made by Company to work with local governmental agencies to pre-qualify Customers where administratively feasible. Customer accounts must be re-qualified annually.

B. **Nonresidential Customer**: A Late Payment Charge shall be added to any Nonresidential Customer account for which bill payment is not received and credited by Company within fifteen (15) days from the current billing date.

46. **Delinquent Bills:** Bills become delinquent if not paid on or before the past due date as shown on bill and service may be discontinued upon five (5) days written notice, excluding Sundays and legal holidays, to Customer after becoming delinquent. During the Cold Weather Rule months, October 1 through April 30, service may be disconnected only as provided in section 60 and Minnesota Statutes, section 216B.096. For residential customers, such written notice of disconnection shall specify a disconnection date not earlier than the third working day after the next scheduled billing date.

47. **Unlawful Use of Service:** In any case of tampering with meter installation or interfering with the proper functioning thereof or any other unlawful use or diversion of service by

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any person, or evidence of any such tampering, interfering, unlawful use or service diversion, Customer is liable to immediate discontinuance of service, without notice, and to prosecution under applicable laws, and Company shall be entitled to collect from Customer at the appropriate rate for all power and energy not recorded on the meter by reason of such tampering, interfering, or other unlawful use or service diversion (the amount of which may be estimated by Company from the best available data), and also for all expenses incurred by the Company on account of such unauthorized act or acts.

48. **Charge for Restoring Service:** If service to Customer is discontinued by Company for valid cause, then before service is restored, Customer shall pay Company all permitted costs of discontinuing and restoring service. There will be no charge for reconnection when service has been discontinued in the event of a condition determined to be hazardous to Customer, to other Customers of Company, to Company's equipment, or to the public.

If Customer requests that service be discontinued and subsequently requests restoration of service at same premises within twelve (12) months of discontinuance, the charge for restoring service will be the sum of minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service.

49. **Selection of Schedule:** The Company's Rate Schedules are designed for service supplied to Customer on a continuous annual basis. Customer may elect to take service under any of the Rate Schedules applicable to such service. Company will advise Customer of the Rate Schedules which, in its judgment, are best adapted to Customer's needs on an annual basis, but such advice must be based upon Customer's statements as to Customer's installation and requirements for service and Company assumes no responsibility for the selection of the Rate Schedule made by Customer. If Customer changes selection of a Rate Schedule, Customer may not go back to the previous Rate Schedule for a period of twelve (12) months; provided, however, that a Large Light and Power Customer whose normal monthly firm demand is below 50,000 kW shall be billed on the Large Power Service Schedule in months in which its measured demand, as adjusted for power factor, exceeds 50,000 kW, and shall go back to the Large Light and Power Service Schedule when its demand falls below 50,000 kW. Rules applicable to specific Rate Schedules shall apply when Customer desires service on other than a continuous annual basis, or the term of service provision of the Rate Schedule is greater than one (1) year.

If, for any cause a Service Agreement is entered into in which is specified a Rate Schedule not applicable to the class of service taken, on discovery of the error all bills rendered during the preceding twelve (12) months will be recalculated in accordance with the properly applicable Rate Schedule and Company will refund to existing Customer any amount due, when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due, when the amount due exceeds two ($2.00) dollars, or Company will bill Customer for any amount owed, when the amount owed exceeds ten ($10.00) dollars, as the case may be. If the amount due Company is not paid within ten (10) days from presentation of bill, or Customer does not agree to payment over a reasonable period of time, or Customer fails to sign a new Service Agreement, Company may, after five (5) days written notice excluding Sundays and legal holidays, disconnect service.

50. **Proration of Bills:** Bills for energy used during a billing period that is longer or shorter than the normal billing period by more than five (5) days shall be prorated on a daily basis, but no billing will be made for three (3) or less days when no energy is used. However, in no event will the total length of service between initial and final service be taken as less than one (1) month. No bill will be prorated for change in operating level within the billing period.

51. **Company Billing Errors:** When a Customer has been overcharged or undercharged as a result of incorrect reading of the meter, incorrect application of rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant or other similar reasons, the amount of the overcharge shall be refunded to the Customer or the amount of the undercharge may be billed to the Customer as detailed in Minnesota Administrative Rules 7820.3800 subparts 2 through 4.

A. **Remedy for Overcharge:** If a Customer was overcharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, plus interest up to a maximum of three years from the date of discovery. Interest will be calculated as prescribed by Minnesota Statutes, section 325E.02(b). If the recalculated amount indicates that more than $1.00 is due an existing Customer or $2.00 is due a person no longer a Customer of the Company, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the Customer.

B. **Remedy for Undercharge:** If a Customer was undercharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, for the period beginning one year before the date of discovery. If the recalculated amount due the Company exceeds $10.00, the Company may bill the Customer for the amount due. The Company must not bill any undercharge incurred after the date of a Customer inquiry or complaint if the Company failed to begin investigating the matter within a reasonable time and the inquiry or complaint ultimately resulted in the discovery of the undercharge.

C. **Exception if Error Date Known:** If the date the error occurred can be fixed with reasonable certainty, the remedy shall be calculated on the basis of payments for service rendered after that date, but in no event for a period beginning more than three years before the discovery of an overcharge or one year before the discovery of an undercharge.

SECTION IX - DEPOSITS AND GUARANTEES

52. **When Required:** Company may require Customer to make a deposit or guarantee satisfactory to Company to secure the payment of bills as they become due. Specific conditions requiring deposits or guarantees are identified in Regulation 54. The amount of such deposit shall not exceed twice the average monthly bill of Customer as estimated by Company from Customer's statement in his or her application or as thereafter ascertained.

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53. **When Refunded:** The deposit shall be refunded to Customer after twelve (12) consecutive months of prompt payment of all Company bills. Company may, at its option, refund the deposit by direct payment or as a credit on the bill. Upon termination of service, the deposit with accrued interest shall be credited to Customer's final bill and the balance, if any, shall be returned within forty-five (45) days to Customer with a written receipt as required under Minn. Stat. 325E.02(b).

54. **Interest on Deposits:** Interest shall be paid annually on all deposits at the rate specified by Minn. Stat. 325E.02(b) or other applicable laws of the State of Minnesota and will be applied against the electric service bill. Any unpaid interest at time of final settlement of Customer's accounts will be credited to Customer's accounts.

55. **Conditions Requiring a Deposit or Guarantee:** Company may require a deposit or guarantee of payment as condition of obtaining new service or continuing existing service under Minn. Rules Part 7820.4300, 7820.4400 or as may otherwise be provided below.

A. Customer has outstanding a prior utility service account with another electric or gas utility which at the time of request for service remains unpaid and not in dispute.

B. Information requested under Minn. Rules Part 7820.4300 or 7820.4400 is not provided within twenty (20) days of the request for service (except where Customer has sought but not yet received credit information from a prior utility).

C. Information provided pursuant to Minn. Rules Part 7820.4300 or 7820.4400 is determined to be false or erroneous.

56. **Conditional Service Prior to Establishment of Credit:** Conditional service shall be provided expeditiously upon receipt of an application for service, and for up to twenty (20) days until credit has been satisfactorily established. Conditional service may be disconnected immediately without notice if required information or a required deposit or guarantee has not been received twenty (20) days after Company's request.

SECTION X – COLD WEATHER RULE

57. **Applicability:** This section applies only to residential customers of the Company.

58. **Definitions:**

A. The terms used in this section have the meanings given them in Minnesota Statute, 216B.096.

B. "Cold weather period" means the period from October 1 through April 30 of the following year.

C. "Customer" means a residential customer of the Company.

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D. "Disconnection" means the involuntary loss of Company heating service as a result of a physical act by the Company to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts Company service in any way.

E. "Household income" means the combined income, as defined in Minnesota Statutes 290A.03, subdivision 3, of all residents of the Customer's household, computed on an annual basis. Household income does not include any amount received for energy assistance.

F. "Reasonably timely payment" means payment within five working days of agreed-upon due dates.

G. "Reconnection" means the restoration of Company heating service after it has been disconnected.

H. "Summary of rights and responsibilities" means a Commission-approved notice that contains, at a minimum, the following:
   1. an explanation of the provisions of subdivision 5;
   2. an explanation of no-cost and low-cost methods to reduce the consumption of energy;
   3. a third-party notice;
   4. ways to avoid disconnection;
   5. information regarding payment agreements;
   6. an explanation of the Customer's right to appeal a determination of income by the Company and the right to appeal if the Company and the Customer cannot arrive at a mutually acceptable payment agreement, and a list of names and telephone numbers for county and local energy assistance, and weatherization providers in each county served by the Company.

I. "Third-party notice" means a commission-approved notice containing, at a minimum, the following information;
   1. a statement that the Company will send a copy of any future notice of proposed disconnection of Company heating service to a third party designated by the residential customer;
   2. instructions on how to request this service; and
   3. a statement that the residential customer should contact the person the Customer intends to designate as the third-party's name.

J. "Company" means Minnesota Power.

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K. "Company heating service" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the Customer's primary residence.

L. "Working days" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing a notice shall not be counted in calculating working days.

59. **Company Obligations Before Cold Weather Period:** Each year, between August 15 and October 1, the Company must provide all Customers, personally or by first class mail, a summary of rights and responsibilities. The summary must also be provided to all new residential customers when service is initiated.

60. **Notice Before Disconnection During Cold Weather Period:** Before disconnecting Company heating service during the cold weather period, the Company must provide, personally or by first class mail, a commission-approved notice to a Customer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of right and responsibilities.

61. **Cold Weather Rule:**

A. During the cold weather period, the Company may not disconnect and must reconnect Company heating service of a Customer whose household income is at or below 50 percent of the state median income if the Customer enters into and makes reasonably timely payments under a mutually acceptable payment agreement with the Company that is based on the financial resources and circumstances of the household; provided that, the Company may not require a Customer to pay more than ten percent of the household income toward current and past Company bills for Company heating service.

B. The Company may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the Customer

C. The Customer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the Customer's financial circumstances have changed or the Customer is unable to make reasonably timely payments.

D. The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the Customer and the Company

E. The Company shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration Customer availability.

62. **Verification of Income:**

A. In verifying a Customer's household income, the Company may:

1. accept the signed statement of a Customer that the Customer is income eligible;
2. obtain income verification from a local energy assistance provider or a government agency;

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3. consider one or more of the following:
   i. the most recent income tax return filed by members of the Customer's household;
   ii. for each employed member of the Customer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;
   iii. documentation that the Customer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension provider; a letter showing the Customer's dismissal from a job or other documentation of unemployment; or
   iv. other documentation that supports the Customer's declaration of income eligibility.

B. A Customer who receives energy assistance benefits under any federal, state or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

63. **Prohibitions and Requirements:**

A. Section 63 applies during the cold weather period.

B. The Company may not charge a deposit or delinquency charge to a Customer who entered into a payment agreement or a Customer who has appealed to the Commission under Minnesota Statutes 216B.096 subdivision 8.

C. The Company may not disconnect service during the following periods:

1. during the pendency of any appeal under Minnesota Statutes 216B.096 subdivision 8;
2. earlier than ten working days after the Company has deposited in first class mail, or seven working days after the Company has personally served, the notice required under Minnesota Statutes 216B.096 subdivision 4 to a Customer in an occupied dwelling;
3. earlier than ten working days after the Company has deposited in first class mail the notice required under Minnesota Statutes 216B.096 subdivision 4 to the recorded billing address of the Customer, if the Company has reasonably determined from an on-site inspection that the dwelling is unoccupied;
4. on a Friday, unless the Company makes personal contact with and offers a payment agreement consistent with this section to the Customer;
5. on a Saturday, Sunday, holiday , or the day before the holiday;
6. when Company offices are closed;
7. when no Company personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service, or;

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8. when Commission offices are closed.

D. The Company may not discontinue service until the Company investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the Company to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the Company must attempt a second contact during non-business hours. If personal contact is made, the Company representative must provide notice required under Minnesota Statutes 216B.096 subdivision 4 and, if the Company representative is not authorized to enter into a payment agreement, the telephone number the Customer can call to establish a payment agreement.

E. The Company must reconnect Company service if, following disconnection, the dwelling is found to be occupied and the Customer agrees to enter into a payment agreement or appeals to the Commission because the Customer and the Company are unable to agree on a payment agreement.

64. **Disputes, Customer Appeals:**

A. The Company must provide the Customer and any designated third party with a Commission-approved written notice of the right to appeal:

1. the Company determination that the Customer’s household income is more than 50 percent of state median household income; or
2. when the Company and Customer are unable to agree on the establishment or modification of a payment agreement.

B. A Customer’s appeal must be filed with the Commission no later seven working days after the Customer’s receipt of a personally served appeal notice, or within ten working days after the Company has deposited a first class mail appeal notice.

C. The Commission must determine all Customer appeals on an informal basis, within 20 working days of receipt of a Customer’s written appeal. In making its determination, the Commission must consider one or more of the factors in Minnesota Statutes 216B.096 subdivision 6.

D. Notwithstanding any other law, following an appeals decision adverse to the Customer, the Company may not disconnect Company heating service for seven working days after the Company has personally served a disconnection notice, or for ten working days after the Company has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

65. **Customers Above 50 Percent of State Median Income:** During the cold weather period, a Customer whose household income is above 50 percent of state median income:

A. has the right to a payment agreement that takes into consideration the Customer's financial circumstances and any other extenuating circumstances of the household; and

B. may not be disconnected and must be reconnected if the Customer makes timely payments under a payment agreement accepted by the Company.

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SECTION XI – RESIDENTIAL CUSTOMER PROTECTIONS

66. **Applicability:** The provisions of this section apply to residential customers of the Company

67. **Budget Billing Plans:** The Company shall offer a Customer a budget billing plan for payment of charges for service, including adequate notice to Customer prior to changing budget payment amounts.

68. **Payment Agreements:** In compliance with Minnesota Statute 216B.098, the Company shall offer a payment agreement for the payment of arrears for past due customers that have not yet been disconnected, or to customers disconnected during non-Cold Weather Rule months. During Cold Weather Rule months, Cold Weather Rule provisions will apply. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a broken payment agreement immediately preceding disconnection or has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected. Under these circumstances, to be reconnected, all past due accounts, deposits and reconnection fees, where applicable, shall have been paid.

69. **Undercharges:**

A. In compliance with Minnesota Statutes 216B.098, the Company shall offer a payment agreement to Customers who have been undercharged if no culpable conduct by the Customer or resident of the Customer's household caused the undercharge. The agreement must cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the Customer and the Company, except that the duration of a payment agreement offered by the Company to a Customer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the Customer's household.

B. No interest or delinquency fee may be charged as part of an undercharge agreement under this subdivision.

C. If a Customer inquiry or complaint results in the Company's discovery of the undercharge, the Company may bill for the undercharges incurred after the date of the inquiry or complaint only if the Company began investigating the inquiry or complaint within a reasonable time after it was made.

70. **Medically Necessary Equipment:** The Company shall reconnect or continue service to a Customer's residence where a medical emergency exists or where medical equipment requiring electricity necessary to sustain life is in use, provided that the Company receives from a medical doctor written certification, or initial certification by telephone and written certification within five business days, that failure to reconnect or continue service will impair or

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threaten the health or safety of a resident of the Customer's household. The Customer must enter into a payment agreement.

71. **Commission Authority:** In addition to any other authority, the Commission has the authority to resolve Customer complaints against the Company, whether or not the complaint involves a violation of this Chapter 216B of Minnesota Statutes. The Commission may delegate this authority to Commission staff as it deems appropriate.

SECTION XII - MISCELLANEOUS REGULATIONS

72. **Conflicts:** In case of conflict between any provision of these approved Service Regulations, Customer's Service Agreement or a Rate Schedule, the provision of the Service Agreement takes precedence, followed by the provision of the Rate Schedule. The Customer's Service Agreement will identify all such conflicts with the Service Regulations or Rate Schedule.

73. **Franchise Limitations:** All Service Agreements are subject to existing franchise limitations.

74. **Franchise Fees Notification:** The Company will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Company receives less than 60 days' notice of a repealed or reduced fee from a city, the Company will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

75. **Franchise Fees Customer Notification:** The following language will be included with the first customer bills on which a new or amended franchise fee is collected:

> The City of ________granted Minnesota Power a franchise to operate within the City limits. An electric franchise fee of (____% OF GROSS REVENUES or $_____ PER METER or $_____ PER KWH) will be imposed on customers effective MM/DD/YYYY. The line item appears on your bills as "_____________Franchise Fee." Minnesota Power remits 100% of this fee to the City of __________.

76. **Regulation and Jurisdiction:** Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable Rate Schedule or other superseding Rate Schedules in effect from time to time. All the rates and regulations referred to herein are subject to amendment and change by Company. Any such amendments or changes may be subject to acceptance or approval by any regulatory body having jurisdiction thereof.

EXTENSION RULES

I. GENERAL

The following rules shall govern the extension of Company's electric transmission/distribution lines and service connections in all areas served by Company to all classes of retail Customers requiring Company's standard single or three phase electric transmission/distribution service.

The standard type of extension shall be the most feasible and economical as determined by the Company and shall be constructed in accordance with Company's Distribution Construction Standards. When conditions require extensions from or connections to lines of voltages other than the standard voltage or where line construction other than Company's standard construction is required, Company reserves the right to make adjustments to these rules for such non-standard extensions such that adequate revenues are provided to fund the extension cost for a single point of delivery. The Company's standard extension does not include a second service point.

Except when meter pedestals for underground service have been installed, all facilities installed by Company on either side of the service point and not expressly sold and conveyed to Customers by written agreement shall at all times remain the sole property of Company, regardless of any Contributions in Aid of Construction paid by Customers. When meter pedestals have been installed by Company, Customer shall be responsible for installing and will remain the sole property owner of all facilities on Customer's side of the meter. In case of cancellation of Customer's service agreement for any cause, Company shall have the right to remove all facilities installed for serving Customer.

Service will be supplied in accordance with Company's schedules for the respective classes of service in the respective rate areas, Company's Electric Service Regulations and the provisions of these Extension Rules.

II. EXTENSION COST

The "Extension Cost" is the estimated cost of extending lines and the addition or relocation of facilities to serve new Customers or new loads. This shall be the total cost of extending the line, including all branch or lateral lines, but excluding the cost of transformer, meter and any system betterments. The Extension Cost shall include the customer's choice of either an overhead or underground service point and projections of special condition costs anticipated.

III. EXTENSION COST CALCULATION

The Extension Cost shall be calculated by Company as follows:

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1. All single phase line extensions of 1,000 feet or less shall be calculated using a unit cost of $32.00 per foot. The unit cost of $32.00 per foot may be adjusted for non-standard extensions or special conditions.

2. All single phase line extensions over 1,000 feet and all three phase line extensions shall be estimated based on Company's Compatible Unit Estimator (CUE). The CUE consists of Compatible Units Identifications (CU IDs), which contain descriptions and costs of service-extension components such as distribution materials, labor, and vehicle usage. The service-extension designer chooses the necessary CU IDs needed for the line extension. A total job cost is estimated using the CUE based on data for the applicable CU IDs. The distribution material cost is the actual cost of items listed in the Company's inventory data base, based on actual purchase prices. The labor cost is based on one lead lineman and two linemen, the typical crew used to install a new service extension. The vehicle use cost is based on a percentage of labor based on prior year actual labor overheads.

IV. CONTRIBUTIONS

The "Contribution in Aid of Construction," hereafter referred to as Contribution, is the additional amount required to support the Company's Extension Cost. Where a line extension other than Company's standard type extension is requested by the customer, a Contribution shall be required to support all additional costs of such non-standard extension. A customer may request a second service point. Additional facilities that may be required to provide that include transformers, cable, switches, and associated equipment. The Company may place additional facilities at the Company's cost only when needed for capacity. If the Company has the capacity (transformer and other equipment ratings) to service the customer from a single service point, a Contribution is required to support all additional facilities requested by the customer.

Any customer may pay all or part of a Contribution required of another Customer with such other Customer's authorization, and subject to acceptance by Company.

V. BASIS FOR MAKING EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS ARE $30,000 OR LESS

If the Company's standard type construction is used in making the extension, Customer shall not be required to make payment to Company for the Extension Cost if:

The Extension Cost is for a Residential customer and does not exceed $682 for single-phase;

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The Extension Cost is for a General Service or Commercial Electric Vehicle Charging Service customer and does not exceed $934 for single-phase and $2,889 for three-phase; or

The Extension Cost is for a Large Light and Power customer and does not exceed $30,000.

If the extension cost exceeds the respective rate class service-extension allowance specified above and is for single phase service, customer must pay the Company in advance a Contribution for the Extension Cost in excess of the respective rate class service-extension allowance.

If the Extension Cost exceeds the respective rate class service-extension allowance specified above and is for non-single phase service, Customer has the following options:

1. Pay Company in advance a Contribution for the Extension Cost in excess of the rate class service-extension allowance, or
2. No advance contribution for extension costs will be required, if the customer enters into a five year Electric Service Agreement where the Company's costs relating to the entire extension are equal to or less than three times the Customer's Guaranteed Annual Revenues (GAR), as defined below, or
3. If the Customer enters into a five-year Electric Service Agreement where the Company's costs relating to the entire extension are greater than three times the Customer's guaranteed annual revenues, the Customer will be required to pay the Company in advance a Contribution for the balance of the Extension Cost not supported by GAR.

The Guaranteed Annual Revenue (GAR) is the minimum annual amount of revenue from billings under the applicable rate schedule that a Customer who enters into an Electric Service Agreement (ESA) commits to pay to Minnesota Power to support extension costs for installing a three phase line extension.

To determine the required GAR, the Company estimates the costs of the service extension from which the revenue is derived. The service-extension job is estimated using the Compatible Unit Estimator (CUE). The cost estimate is divided by three according to the three-times-annual-revenue methodology. This is the annual amount the Customer will pay under the GAR agreement.

The GAR used in the ESA shall be estimated by the Company and determined under the existing rate schedule for providing service to the Customer.

Developers of Residential Housing Sites

A Developer of residential housing sites requiring electric service must make a Contribution equal to the Extension Cost, but excluding the cost of service drops. As customers are connected Developer is entitled to receive a refund for each customer connected of the current residential allowance amount less the estimated cost of the service drop for that customer. However, in no event will the total refund exceed the Contribution. After Developer has received the maximum allowable refund or after the initial five years, whichever occurs first, customers requesting service to additional lots for which the extension was made shall make appropriate arrangements directly with Company in order to satisfy additional extension costs related to the respective service connections.

VI. BASIS FOR MAKING EXTENSIONS FOR TEMPORARY SERVICE

"Temporary Service," for purposes of these Extension Rules, is service to a Customer whose use of that service, in the Company's judgment, may be of less than five years duration, or is service to a Customer who is unwilling to enter into an Electric Service Agreement having a minimum term of five years.

Customers expected to take service for less than one year duration shall be required to take such service in accordance with Company's Temporary Service Rider to the applicable General Service Schedules.

Customers expected to take Temporary Service for more than one year but less than five years will be served under the Company's standard rate schedules. Such customers with requirements of 500 kW or more shall enter into a contract for a minimum term of one year.

Prior to installation Temporary Service Customers shall pay a Contribution equal to the estimated cost of installation and removal, less salvage, of the facilities required to render Temporary Service. Where the actual cost is different from the estimated costs upon which the advance payment was based, as determined upon termination of Temporary Service, Company will refund any excess payment made by Customer or render a bill for any additional amounts due.

A connection to a permanent service for power used during construction is not considered to be Temporary Service under these rules.

VII. REAPPORTIONMENT AND REFUNDS

When the Extension Cost is $30,000 or less and additional Customer(s) are connected to a line extension during the initial five year period of any Customer on the extension, the

EXTENSION RULES

Extension Cost(s) of all previously connected Customer(s) on the extension will be reapportioned among all Customers served from the combined line extension, including the Customer(s) who are being added to the extension. The reapportionment shall be calculated such that each individual customer on the line extension shall be responsible for:

1. The cost of that portion of the extension which services only that individual Customer; plus

2. The cost of that portion of the line extension which that individual Customer shares with other Customers on the line extension divided by the total number of Customers who share such portion of the line extension.

After reapportionment it will be determined whether the previously connected Customer(s) are entitled to a refund. If a refund is due, the amount to be refunded shall be the difference between the previous and reapportioned Extension Costs, provided that such refunds will not:

1. Exceed the actual Contribution paid by the respective Customer.

2. Be made to any Customer after the expiration of the initial five year period of that Customer.

3. Be made after Customer terminates service.

When a Customer who has paid a Contribution terminates service within the initial five year period and another Customer immediately commences taking service at the same premises, such Customer may transfer his right to future refunds, if any, to the new Customer, provided an agreement covering such transfer is executed by the Customers and accepted by the Company at the time the new Customer applies for service. If the Customer terminating service had entered into an Electric Service Agreement, such transfer of rights will be acceptable to the Company when the new Customer has entered into an Electric Service Agreement guaranteeing annual revenues equal to the amount specified in the current agreement.

Following the initial five year period of the most recently connected Customer(s) on the extension, any line extension necessary to serve additional Customers will be considered as a separate extension not affecting Customers connected previously.

Following the expiration of Customer's five year Electric Service Agreement, the annual revenue guarantee will be discontinued for purposes of supporting the line extension and Customer will continue to be served under the provisions of the applicable rate schedule.

EXTENSION RULES

When the Extension Cost is $30,000 or less and the Customer has entered into an Electric Service Agreement and paid a Contribution, the Company will, through its Customer Information System, at the end of the each year of the Electric Service Agreement, compare the Customer's average annual revenue for the first year and thereafter, to the minimum annual revenue which Customer elected to guarantee. The Company will, at the election of the Customer:

1. Refund to the Customer all or a portion of the Contribution but not to exceed an amount equal to the difference between the extension cost supported by the annual revenue and the extension cost supported by the minimum annual revenue the Customer elected to guarantee; or

2. Collect an additional contribution from the Customer not to exceed an amount equal to the difference between the extension cost supported by the revenue for the first year and the extension cost supported by the minimum annual revenue the Customer elected to guarantee; or

3. Continue the minimum guaranteed annual revenues set forth in the existing Electric Service Agreement.

In no event will the minimum annual guarantee be greater than the amount necessary to satisfy the Extension Cost.

VIII. SPECIAL CONDITIONS

Construction of an extension will commence when the following conditions have been met.

1. Agreements, when required, shall have been executed by each Customer and accepted by Company specifying initial contract period, guaranteed annual revenue, and any Contribution.

2. Each Customer has paid to Company his share of any Contribution.

3. Satisfactory right-of-way necessary for the construction, operation and maintenance of the extension (including any vegetation management rights) both for the purpose of providing access to the extension on Customers' premises and for continuing the extension to other Customers, has been furnished without expense to the Company.

4. Each Customer has made satisfactory credit arrangements with the Company. In the case of tenants, the Company may require owner to guarantee payment.

EXTENSION RULES

5. The extension cost will include excess installation costs incurred by the Company because of special conditions that impede the installation of distribution facilities. Such special conditions include, but are not limited to ground frost, surface or subsurface impediments and submarine installations. Surface or subsurface impediments may include, but are not limited to: rock, bedrock, subsurface structures and wetlands.

IX. BASIS FOR MAKING DISTRIBUTION EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS EXCEED $30,000

The above rules shall be applicable except where specifically stated otherwise and except that the Extension Cost will be the actual cost determined upon completion of the extension. The amount of Extension Costs relating to the extension which will be recovered by the Company through application of its rate schedule will be determined on an individual customer basis. Electric Service Agreements will be required and will be for sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

If the Extension Cost exceeds the Extension Cost Credit as determined by the Company, the Customer(s) shall pay the Company a Contribution equal to the amount of the Extension Cost that exceeds the Extension Cost Credit. Where more than one Customer is served from the extension, the Contribution will be apportioned in the ratio of each Customer’s Contract Demand to total Contract Demand for all Customers initially served from the extension. If there are circumstances unique to an extension in which application of the above rules would not be appropriate or would not properly recover costs, the Company will make necessary adjustments in the application of the rules such that adequate revenues are provided to fund Extension Costs through a combination of Extension Cost Credits and/or Contributions. Similarly, any refund which may be due, as a result of increased Customer Contract Demand during the initial ten year period, or as a result of additional Customers being served subsequently but during the initial ten year period, will be determined by the Company based upon all relevant dates such that revenue recovery is adequate to fund the Extension Costs through a combination of Extension Cost Credits and/or Contributions.

X. BASIS FOR MAKING TRANSMISSION EXTENSIONS FOR PERMANENT SERVICE

“Transmission” service for purposes of these Extension Rules is service to a Customer taken at 115 kV or higher. Customer connections involving loads served at transmission voltage will be considered on an individual customer basis. Electric Service Agreements will be required and will be of sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

BUDGET BILLING PLAN

Any all-year retail customer may apply for service to be billed in accordance with Company's Budget Billing Plan by completing Form No. 1326, "Budget Billing Service Request Form" or the applicable form available at http://www.mnpower.com. Billing under this plan shall commence upon acceptance of the application by Company. Company may require partial payment of arrears for those customers who wish to include a large arrears balance in a newly established budget billing plan.

The amount of the monthly budget billings shall be determined as follows:

1. Where sufficient billing history is available,

   A. Company will determine Customer's average monthly billing during the preceding 12 months

   B The average monthly billing determined in Step A shall be adjusted for anticipated changes in rate level during the following 12 months.

   C. An existing arrears or credit balance shall be divided by twelve and added to or deducted from the amount determined in Step B.

   D. The amount of the monthly budget billing shall then be the amount determined in Step C rounded to the nearest dollar.

2. Where insufficient billing history is available, Company will determine Customer's connected load for use in estimating the first year's consumption upon which to base budget billings.

Customer's budget billings shall be reviewed and recalculated annually on the date following preparation of the twelfth billing under an existing budget billing plan. Company may also review Customer's account at times other than the normal review date and, where an unusually large arrears or credit balance exists, adjust the budget billing amount accordingly. Customer shall be notified of such adjustment made in the budget billing amount. When there is an unusually large credit balance, Customer may request a refund and/or reduction of budget billings.

Customer may discontinue budget billing at any time by notifying Company. Company may discontinue budget billing upon failure of the Customer to make timely payments of budget billings. Any credit balance remaining at the time of discontinuance in the Plan shall be carried forward unless Customer requests a refund. Any amount past due shall be treated under Company's normal notice and collection procedures.

REQUEST FOR BUDGET BILLING PLAN FORM

Form No. 1326 Rev. 10/78

MINNESOTA POWER

REQUEST FOR BUDGET BILLING PLAN

Name ______________________ Date ______________________

Address ______________________ Account No. ______________________

ESTIMATED COST OF ELECTRIC SERVICE FOR _____ MONTHS ENDING _______________ 20 _____ $______________
(Based on rate schedules available at our office.)

AMOUNT OF MONTHLY BUDGET INSTALLMENT (to be shown in even dollars) $______________

This Budget Billing Plan is available to All Retail Customers. No guarantee of total cost is implied. It will remain in force until canceled by the customer, or may be canceled by the Company upon failure of the customer to make timely payments of installments. If such a cancellation is necessary, the account will then revert to our regular billing and collection practice.

This account will be reviewed annually in ______________________ by the Company for possible adjustments of installments. Any credit balance remaining will be carried forward unless the customer requests a refund. Any debit balance owing may be paid at this time or included in the newly revised budget amount.

______________________ ______________________
(For Company) (Customer's Signature)

STANDARD CONTRACTS AND AGREEMENTS

Form 6174 5/07

minnesota power

MINNESOTA POWER
APPLICATION FOR RESIDENTIAL ELECTRIC SERVICE

Please send completed form to 30 W Superior St. Duluth, MN 55802, fax to 218-720-2770, or apply online at www.mnpower.com.

Last Name ______ First ______ Middle ______

Account # ______
Date to Start Service ______
Own ☐ Rent ☐
Landlord Name ______
Landlord Phone # ______

Service Address ______
City ______ State ______ Zip ______
Mailing Address ______
City ______ State ______ Zip ______
Primary Phone # ______ Cell Phone # ______
Employer ______ Employer Phone # ______
SSN ______ Driver's License # ______ State ______ Other ID ______
Previous Address ______ City/State/Zip ______
Have you ever been a customer of Minnesota Power? Yes ☐ No ☐
If yes, prior service address ______
Contact Person not living with applicant ______ Relationship ______
Address ______ City/State/Zip ______ Phone # ______
Primary Signature ______ Email Address ______

Spouse/Roommate: All adults receiving electric service at this premise are required to be listed on the account and will be held equally responsible for charges incurred.

Last Name ______ First ______ Middle ______ Social Security # ______
Driver's License # ______ State ______ Cell Phone # ______
Employer ______ Employer Phone # ______
Previous Address ______ City/State/Zip ______
Contact Person not living with applicant ______ Relationship ______
Address ______ City/State/Zip ______ Phone # ______
Secondary Signature ______ Email Address ______

Please notify Minnesota Power when you move. You are responsible for all electric bills through the date we are notified.

→→→→→→→
Adults/Roommates complete reverse side

STANDARD CONTRACTS AND AGREEMENTS

Form 351 Rev. 1/00

ELECTRIC SERVICE AGREEMENT

THIS AGREEMENT, made this __________ day of ________________ , _________, between Minnesota Power, a Minnesota corporation, and ____ , hereafter called Customer, in consideration for the covenants and promises made herein creates the obligation of Minnesota Power to furnish electric service and Customer to pay for said electric service in accordance with the following terms and conditions.

1. Electric service shall be furnished to Customer's premises located at ____________________________________
   ____
   in the County of _________________ and State of Minnesota, described as follows:

2. Electric service shall be furnished at a point of delivery described as ____________________________________
   ____

3. Annual revenues paid to Minnesota Power by Customer inclusive of payments for electric service received, billed at the applicable rate schedule plus any adjustments shall not be less than ___________________ per year, for a period of not less than _____________ years, commencing from the date Minnesota Power begins providing electric service or 90 days from the date of installation of said electric service, whichever occurs first. An annual billing will be rendered for any deficit to the above annual revenue guarantee.

4. An advance payment of _______________ shall be made to cover that portion of Minnesota Power's investment not covered by the revenue guarantee.

5. This electric service shall be billed at the current applicable rate and class at the time the electric service is used or as approved by any regulating body having jurisdiction thereof.

6. Meter-Special Conditions:____
   ____
   ____

7. The parties hereto mutually agree to abide by any and all applicable statutes, agency rules and Minnesota Power's Electric Service Regulations which are hereby incorporated by reference.

8. This Agreement is not assignable to any other party without the express written consent of Minnesota Power.

9. This Agreement shall be in full force and effect for the term above specified and each party shall be bound unless an express written release is executed by the party not requesting said release.

MINNESOTA POWER

By ____

Title ______________________________________

CUSTOMER

____

By ____

Title ______________________________________

RESERVED FOR FUTURE USE

Filing Date ____________________ MPUC Docket No. ____________________

Effective Date ____________________ Order Date ____________________

Approved by: ____________________

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

TERRITORY

Applicable to Community-Based Energy Development (C-BED) projects located in the State of Minnesota.

APPLICATION

To any qualifying owner of a C-BED project who meets Company's Electric Service Regulations and any applicable Riders, technical standards and rules. Service under this Schedule is closed to new customers.

A C-BED project must be a new renewable energy project that utilizes an eligible energy technology, as defined in Minn. Stat. § 216B.1691, subd. 1(a). A C-BED project may either be a stand-alone project or part of a community energy partnership that allows Company participation as an owner, equity partner, or provider of technical or financial assistance:

(1) has no single qualifying owner owning more than 15 percent of a C-BED wind energy project unless: (i) the C-BED wind energy project consists of only one or two turbines; or (ii) the qualifying owner is a public entity listed under Minn. Stat. § 216B.1612, subd. 2(c)(5), that is not a municipal utility;
(2) demonstrates that at least 51 percent of the gross revenues from a power purchase agreement over the life of the C-BED project will flow to qualifying owners and other local entities;
(3) includes a qualifying owner, or any combination of qualifying owners, that may develop a joint venture project with a nonqualifying renewable energy project developer. However, the terms of this Schedule may only apply to the portion of the energy production of the total project that is directly proportional to the equity share of the C-BED project owned by the qualifying owners; and
(4) has a resolution of support adopted by the county board of each county in which the C-BED project is to be located, or in the case of a C-BED project located within the boundaries of a reservation, the tribal council for that reservation;

Where a qualifying owner means:

(1) a Minnesota resident;
(2) a limited liability company that is organized under Minn. Stat. Chapter 322B and that is made up of members who are Minnesota residents;
(3) a Minnesota nonprofit organization organized under Minn. Stat. Chapter 317A;
(4) a Minnesota cooperative association organized under Minn. Stat. Chapter 308A or 308B, including a rural electric cooperative association or a generation and transmission cooperative on behalf of and at the request of a member distribution utility;
(5) a Minnesota political subdivision or local government including, but not limited to, a municipal electric utility, or a municipal power agency on behalf of and at the request of a member distribution utility, a county, statutory or home rule charter city, town,

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

school district, or public or private higher education institution or any other local or regional governmental organization such as a board, commission, or association; or

(6) a tribal council.

TYPE OF SERVICE

Output of the C-BED project shall be provided at 60 hertz and at the voltage and phase relationship as agreed to by Company and a qualifying owner.

RATE

A qualifying owner may sell all the energy produced by the C-BED project to Company or use a portion of the energy from the C-BED project and sell the remaining to Company. The following information provides guidelines for the negotiated power purchase agreements for service under this C-BED Schedule.

Company may purchase all or a portion of the energy made available by the qualifying owner from the C-BED project. A qualifying owner and Company shall negotiate the rate and power purchase agreement terms consistent with this Schedule. In the alternative, at the discretion of a qualifying owner, the qualifying owner and Company may negotiate a power purchase agreement with terms different from this Schedule. Company must receive Minnesota Public Utilities Commission approval of a power purchase agreement for a C-BED project. Nothing in this Schedule shall be construed to obligate Company to enter into a power purchase agreement.

The energy rate shall equal the net present value of the nominal payments to the C-BED project divided by the total expected energy production of the C-BED project over the 20-year life of the power purchase agreement with a rate higher in the first ten years of the power purchase agreement than in the last ten years. The receipt of the payment of this rate constitutes a transfer of the property rights of all renewable and other attributes/credits associated with the generation from the C-BED project to Company, unless otherwise agreed to by the qualifying owners of the C-BED project and Company.

Qualifying and nonqualifying owners shall provide sufficient security as determined by Company based on standard industry practice, risk-adjusted for the C-BED project, that considers such things as ownership arrangement, project accreditation, credit rating and experience of financing sources and project management and project development experience to secure performance under the power purchase agreement, and shall not transfer the C-BED project to a nonqualifying owner during the initial 20 years of the power purchase agreement.

A C-BED project that is operating under a power purchase agreement under this Schedule is not eligible for net energy billing under Minn. Stat. § 216B.164, subd. 3, or for production

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

incentives under Minn. Stat. § 216C.41.

SERVICE CONDITIONS

1. A C-BED project must be: (1) safely integrated into and operated within Company's grid without causing any adverse or unsafe consequences; and (2) consistent with Company's resource needs as identified in Company's most recent resource plan submitted under Minn. Stat. § 216B.2422 and meet Company's cost and reliability requirements to fulfill some or all of the identified need at a minimal impact to customer rates.

2. All electricity delivered to Company by a qualifying owner shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. The meter(s) for C-BED service shall measure the flow of capacity and energy from a qualifying owner to Company only. Any flow of capacity and energy from Company to a qualifying owner shall be separately metered.

3. Service shall be provided under this Schedule if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

4. A qualifying owner shall pay Company the installed cost of any additional required facilities, including any required studies and testing which, at a minimum, demonstrate upfront the C-BED project's technical feasibility and resource adequacy.

5. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Schedule.

RATE, SERVICE, PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Related Company rate, service, process and technical documents for distributed generation are available by contacting Company at 218-722-2625.

SOLARSENSE CUSTOMER SOLAR PROGRAM

APPLICATION

The goal of the Low Income ("LI") Solar Gant Program is to increase the accessibility of solar energy to Customers by creating a viable, long-term solar market for low-income customers in northern Minnesota. Starting in 2021, the annual budget is $120,000 per year, with a maximum individual grant cap of $30,000. This allows for up to four projects per year to be funded at the $30,000 level. A Low Income Solar Grant Committee ("Committee") comprised of both external stakeholders and Minnesota Power employees make project funding recommendations.

GRANT COMMITTEE CONFLICTS OF INTEREST

In order to evaluate possible conflicts, all Low Income Solar Grant Committee candidates must complete a Conflict of Interest disclosure. If it is determined the candidate has a conflict of interest, or the appearance of a conflict of interest, they will not be eligible to join the Committee. The following Conflict of Interest Policy applies to all Grant Committee members.

Existence of Conflict of Interest or Appearance of Conflict of Interest

A conflict of interest exists if a Committee member:

1. Is an applicant for a Low Income Solar Grant, intends to apply for a grant (as an individual or with an organization) in the next two years, or is personally involved as a partner to the project, or
2. Serves on the Board of Directors or other governing or advisory board of an applicant organization, or
3. Is a volunteer or paid employee of an organization being considered for funding, or
4. Is a paid consultant or service provider of an organization being considered for funding, or
5. Has an immediate family member or relation with an applicant that would impair their ability to make a grants award decision.

Minnesota Power also reserves the right to determine when a Grant Committee member's relationship with an individual or organization creates an appearance of a conflict of interest that, in its judgment, could compromise the integrity of the grant process and should be treated as a conflict of interest.

Remedies for Conflicts of Interest

If a Committee member has a conflict of interest as defined above, they must notify Minnesota Power as soon as they are aware of a conflict. Committee members with a conflict of interest have one of two options to remedy the conflict 1) recuse themselves from the entire grant process for that cycle (including the meeting, discussion, and voting) or 2) resign from the committee. Committee members will only be allowed to recuse themselves from one grant cycle. If conflicts persist, the member will no longer be eligible to serve on the Grants Committee.

If Minnesota Power or the committee member identifies a perceived conflict of interest, the Company will make a determination on how to proceed. Possibilities include, but are not limited to:

- Allowing the committee member to remain on the committee and review applications without limitation
- Having the committee member recuse themselves from reviewing the application(s) where a perceived conflict of interest exists but allowing them to review all others
- Recusing the committee member from the entire grant process for that grant cycle.

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

APPLICATION

Available to all customers taking service at Company owned Electric Vehicle Service Equipment (EVSE) charging stations. Service shall be delivered at publicly available charging stations operated by the Company. Stations may include Direct Current Fast Charging (DCFC) and Level 2 EVSE infrastructure served by Company owned facilities.

TYPE OF EQUIPMENT

For purposes of this tariff, Electric Vehicle Service Equipment means the installed device used to deliver electricity for electric vehicle charging and includes the ungrounded, grounded, and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets or apparatuses associated with the installed devices.

PAYMENT COLLECTION METHODS

All Electric Vehicle Service Equipment will have a minimum of two payment options for taking service at Company owned EVSE charging stations.

RATES

Connection Fees:

Level 2 Charger Only:	$3.00
DCFC 100 kW or less:	$5.00
DCFC 101-200 kW:	$6.00
DCFC 200 kW plus:	$7.00

Charge per kWh:	Level 2	DCFC
On-peak (kWh)	31.896¢	45.930¢
Off-peak (kWh)	22.832¢	32.878¢
Super Off-Peak (kWh)	16.183¢	23.304¢

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

EVSE TIME OF DAY PERIODS

On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. CST Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. CST Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak.

Weekdays

Legend	
-1	Super off-peak
0	Off-peak
1	Peak

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1

Weekends & Holidays

Legend	
-1	Super off-peak
0	Off-peak
1	Peak

Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1