215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (website)

May 1, 2024

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

**PUBLIC DOCUMENT -
NOT PUBLIC (OR PRIVILEGED)
DATA HAS BEEN EXCISED**

**RE: In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01
Docket No. E017/AA-24-
Initial Filing**

Dear Mr. Seuffert:

Otter Tail Power Company (Otter Tail) hereby submits to the Minnesota Public Utilities Commission (Commission) its 2025 Forecasted Energy Adjustment Rider rates in response to decisions rendered by the Commission in Docket No. E999/CI-03-802 and where applicable, in compliance with annual reporting requirements pursuant to Minn. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges.

Various portions and attachments to this filing contain information that Otter Tail considers trade secret. Otter Tail believes this filing comports with the Commission's Notice relating to Revised Procedures for Handling Trade Secret and Privileged Data, pursuant to Minn. R. 7829.0500. As required by the revised procedures, a statement providing the justification for excising the trade secret data follows this letter.

If you have any questions regarding this filing, please contact me at 218-739-8282 or at cbyrnes@otpco.com.

Sincerely,

/s/ CHRISTOPHER BYRNES
Christopher Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics

vjm
Enclosures
By electronic filing
c: Service List

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Please note that Otter Tail Power Company has marked the following portions of this filing with the caption **NOT PUBLIC DOCUMENT – NOT FOR PUBLIC DISCLOSURE**, according to Minn. Stat. § 13.37, subd. 1(b). This statute protects certain "government data," as that term is defined at Minn. Stat. § 13.02, Subd. 7, from being disclosed by an administrative agency to the public.

- Portions of Operational Parameters information in Petition;
- Portions of Planned and Forced Outage information in Petition;
- Table 5 of Petition, Otter Tail Plant 2024 Planned Outages;
- Portions of Internal Combustion information in Petition;
- Portions of Wind Generation information in Petition;
- Table 6 of Petition, 2024 Winter Energy Purchase;
- Portions of Wind Curtailment information in Petition;
- Portions of Annual Compliance/Reporting Requirements information in Petition;
- Portions of Attachment 3.1 – Generation and Fuel Forecast details;
- Portions of Attachment 3.2 – Steam and Water Sales forecast details;
- Portions of Attachment 3.3 – Hoot Lake Solar Generation Credit forecast details;
- Portions of Attachment 7 – Municipal Sales details;
- Attachment 12 in its entirety – Rule 7825.2830 Annual Five-year Projection 2024-2028;
- Appendix A Section 1.3, Page 5 - Portions of Procurement of Transportation Services;
- Appendix A Section 3, Page 7 - Portions of Forecast discussion;
- Appendix A Section 3, Pages 8-10 – Hedging discussion
- Portions of Attachment 13 – 2021-2023 Actuals Compared to 2025 Forecast
- Portions of Attachment 14 – Unplanned Actuals to Forecast
- Portions of Attachment 15 – Winter Energy Purchase

The information being supplied in this filing is considered to be a "compilation" of data that (1) was supplied by Otter Tail Power Company, (2) is the subject of reasonable efforts by Otter Tail Power Company to maintain its secrecy, and (3) derives independent economic value, actual or potential, from not being generally known to or accessible to the public.

It is Otter Tail Power Company's understanding that marking the filing in this manner is consistent with the revised procedures for handling trade secret and privileged data, as announced in the joint memorandum of the Office of Energy Security and Public Utilities Commission dated August 18, 1999 and which became effective September 1, 1999.

Date prepared: May 01, 2024

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01	**Docket No. E017/AA-24-**

SUMMARY OF FILING

Otter Tail Power Company (Otter Tail or Company) submits this Petition to the Minnesota Public Utilities Commission (Commission) for approval of its annual forecasted rates for its Energy Adjustment Rider (EAR) under Otter Tail's Rate Schedule Section 13.01 for the calendar year 2025.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01	**Docket No. E017/AA-24-** **PETITION**

I. INTRODUCTION

Otter Tail Power Company (Otter Tail or Company) submits this Petition to the Minnesota Public Utilities Commission (Commission) for approval of its annual forecasted rates for its Energy Adjustment Rider (EAR) under Otter Tail's Rate Schedule Section 13.01 for calendar year 2024.This filing is made in compliance with the December 2018 Order to seek approval of Otter Tail's proposed EAR rates for 2025.

Otter Tail's requested, forecasted total average cost of fuel and purchased power for the calendar year 2025 is $0.023920 per kWh. Table 1 below provides a rounded summary of the monthly cost per kWh Otter Tail forecasts for 2025.

Table 1
Monthly Forecasted Fuel Cost per kWh For Calendar Year 2025 ($/kWh)[1]

Jan	Feb	Mar	April	May	June
$ 0.027132	$ 0.028265	$ 0.022766	$ 0.024166	$ 0.023135	$ 0.020054
July	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
$ 0.020067	$ 0.021183	$ 0.022254	$ 0.021834	$ 0.023976	$ 0.028854

(1) Monthly values based on calculated fuel cost per kWh rates Attachment 2, Line 17

These forecasted rates are computed on an Otter Tail Total (OTP Total) system basis, consistent with how past EAR rates were developed . Customer class specific EAR rates are derived from these amounts by applying class specific Energy Adjustment Factor ratios to the average monthly rates.

In this filing, Otter Tail describes the process and associated assumptions used to develop the forecasted costs reflected above. Specifically, Otter Tail provides: the overall sales forecast and associated assumptions; forecasted costs of fuel, reagents, and associated operations of Otter Tail's owned generation; forecasted purchased power costs and associated assumptions; forecasted non-energy wholesale market charges and associated assumptions;

forecasted wind curtailment expenses and associated assumptions; forecasted asset-based sales; and forecasted costs and revenue from steam and water sales.

Otter Tail's forecast is based on reasonable assumptions and information known at the time the forecast is developed, which is over nine months prior to the effective date of the first month's rate. It is also reasonable to expect that actual results will differ from forecast assumptions, especially if we were to experience periods of energy market price volatility as experienced in recent years and economic uncertainty due to (or exacerbated by) inflation, continued geo-political unrest, evolving energy markets, demands for energy and the sources from which those demands are met. In many cases, those variances are out of the control of Otter Tail. In this filing, Otter Tail provides an overview of various risks inherent in the forecasted rates and summarizes potential impacts to the EAR rates should actual results differ from the forecast. Otter Tail may submit a refreshed FCA forecast with its July 31, 2024 Reply Comments if forecasted sales, market conditions, or owned-generation assumptions have changed substantially from this Initial Filing.

Appendix A to this forecast provides further compliance reporting stemming from prior Commission Rules and Orders as they apply to the forecast information provided in this filing.

II. SUMMARY OF FILING

Pursuant to Minn. Rules 7829.1300, Subp. 1, a one-paragraph summary of the filing accompanies this Petition.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, Subp. 3, Otter Tail provides the following general information.

A. Name, Address, and Telephone Number of Utility.

(Minn. Rules 7829.1300, subp. 3(A))

Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8200

B. Name, Address, and Telephone Number of Utility Attorney.
(Minn. Rules 7829.1300, subp. 3(B))

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8956
cstephenson@otpco.com

C. Date of Filing and proposed effective date of rates.
(Minn. Rules 7829.1300, subp. 3(C))

The date of this filing is May 1, 2024. Otter Tail proposes the forecasted EAR rates become effective in the appropriate months in 2025 as recommended in this Petition following Commission approval. At its April 25, 2019 meeting, the Commission approved a variance to the filing requirement in Minn. R. 7825.2840, allowing Automatic Adjustment of Charges information to be included in this May 1, 2024 filing. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning Automatic Adjustment of Charges, the Commission's June 12, 2019 Order[1] (June 2019 Order) in Docket No. E-999/CI-03-802, and the December 2019 Order.

D. Statute Controlling Schedule for Processing the Filing.
(Minn. Rules 7829.1300, subp. 3(D))

No statute establishes a schedule for processing this filing. The applicable rules are Minn. R. 7825.2800 through 7825.2840. The procedural schedule for this FCA process was adopted by the June 2019 Order.

E. Title of Utility Employee Responsible for Filing.
(Minn. Rules 7829.1300, subp. 3(E))

Chris Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8282
cbyrnes@otpco.com

[1] Order Approving Additional Details of New Fuel Clause Adjustment Process.

F. Impact on rates.

(Minn. Rules 7829.1300, subp 4(F))

The EAR Rates have no effect on Otter Tail's current base rates. The additional information required under this Rule is included throughout the Petition.

G. Service list.

(Minn. Rules 7829.0700)

Otter Tail requests that the following persons be placed on the Commission's official service list for this matter and that any trade secret comments, requests, or information be provided to the following on behalf of Otter Tail:

Chris Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota, 56538-0496
(218) 739-8282
cbyrnes@otpco.com

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota, 56538-0496
(218) 739-8956
cstephenson@otpco.com

Amber Stalboerger
Manager, Regulatory Analysis
Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538-0496
astalboerger@otpco.com

Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
PO Box 496
Fergus Falls, MN 56538-0496
regulatory_filing_coordinators@otpco.com

H. Service on other parties.

(Minn. Rules 7829.1300, subp. 2; Minn. Rules 7829.0600)

Pursuant to Minn. Rule 7829.1300, Subp. 2, Otter Tail served a copy of this Petition on the Department and the Antitrust & Utilities Division of the Office of the Attorney General. A summary of the filing prepared in accordance with Minn. Rule 7829.1300, Subp. 1 was served on all parties on Otter Tail's general service list. Otter Tail also provides notice of availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in Otter Tail's previous two general rate cases as required by the December 2019 Order.[2]

[2] Compliance with the Order Point 6 in the Commission's December 18, 2019, Order in Docket No. E-017/AA-19-297.

IV. DESCRIPTION OF FILING

In *Section A* below, Otter Tail provides a summary of the overall forecasted system sales and forecasted fuel and purchased power costs for January 2025 through December 2025. In *Section B,* Otter Tail provides a general overview of Otter Tail's EAR forecast process. In *Section C*, Otter Tail provides a description of the sales forecast process, and in *Section D*, a description of the EnCompass forecasting modelling software, as well as detail on forecasted fuel, purchased power, and other costs recoverable through the EAR. These descriptions of sales and costs fully support the resulting forecasted rates and fulfill certain Annual Automatic Adjustment (AAA) filing requirements as described in the narrative. *Section E* provides a non-exhaustive list of risks Otter Tail, and its customers are exposed to, along with their related impacts. Finally, additional annual compliance and reporting requirements are described and addressed in *Section F* and in Appendix A.

A. Summary of Overall Sales, Fuel and Purchased Power Costs

Table 2 provides the forecasted 2025 summary of total system sales in Megawatt-hours (MWhs), total system costs, and the annual average cost per MWh. These costs and sales are provided on a monthly and annual basis in Attachment 2, Lines 13 and 15 to this filing.

Table 2
2025 System Sales and Cost

System Sales (MWh)	System Cost ($)	Average ($/MWh)
5,885,378	$ 140,775,339	23.920

Table 3 below summarizes the forecasted annual generation by generation type and proportion by generation type (Column C) used to meet 2025 load needs. This proportion is calculated by dividing the volume supplied per generation type by the Total Generation & Purchases volume (Column B, Line 6).

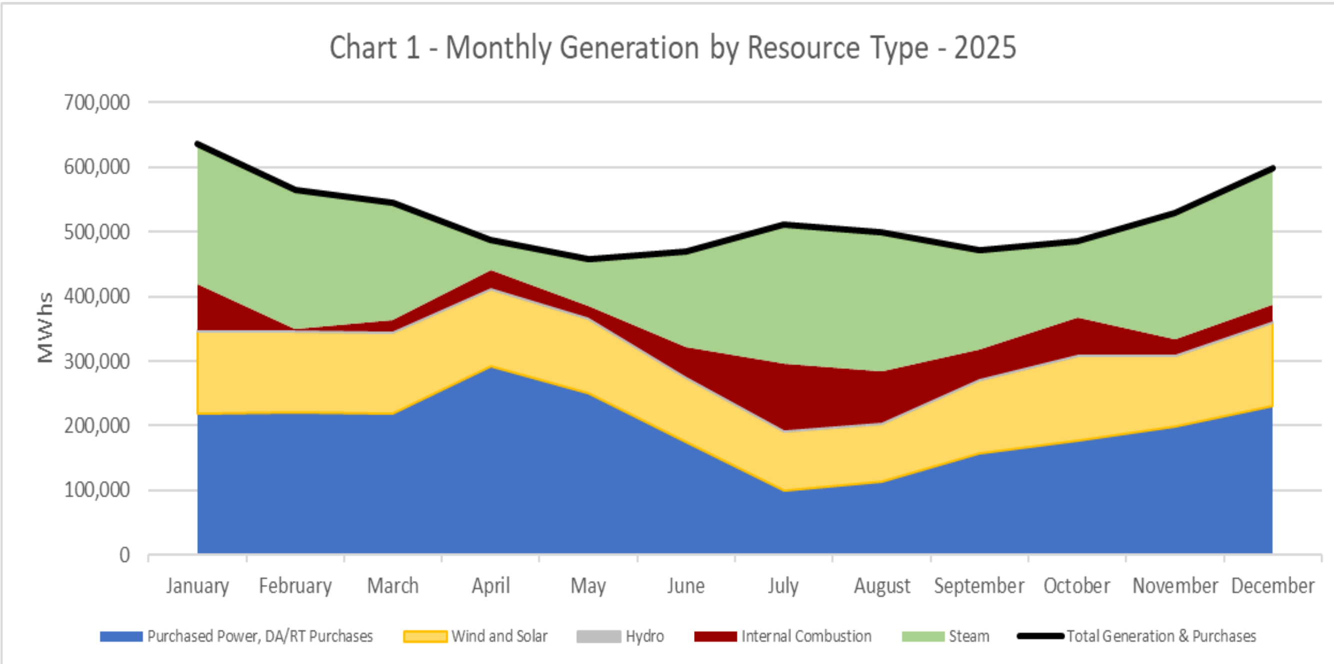
Table 3
Generation Type and Proportion

Line No.	(A) Generation Type	(B) Volume (MWh)	(C) Proportion	
1	OTP Steam Generation	1,986,376	32.5%	(1)
2	OTP Internal Combustion (Peaking and Natural Gas) Generation	520,669	8.5%	(2)
3	OTP Wind & Solar Generation - Owned	1,368,270	22.4%	(3)
4	OTP Hydro Generation	20,000	0.3%	(4)
5	Purchased Power, DA/RT Purchases & Other Market Charges, Wind Curtailment, less Asset-Based Sales	2,225,485	36.4%	(5)
6	**Total Generation and Purchases**	**6,120,800**	**100.0%**	

(1) Attachment 3.1: Line 26
(2) Attachment 3.1: Lines 43 plus 47
(3) Attachment 3.1: Line 35
(4) Attachment 3.1: Line 37
(5) Attachment 3.1: Lines 61 minus Line 63 plus Attachment 5: Line 6

The forecasted Total Generation & Purchases MWhs in Table 3 is greater than the forecasted System Sales in Table 2 due to transmission line losses that occur. Otter Tail assumes approximately 6.36 percent for transmission line losses in this forecast. This value is derived from Otter Tail's 2021 Line Loss Study.

Chart 1 below is an area graph which reflects how each of Otter Tail's generation and energy supply resources is forecasted to meet customer monthly load needs for 2025.



B. Overview of Forecast Process

The EAR forecasting process begins with the development of Otter Tail's system sales forecast, which includes the sales forecasts of four municipal communities to which Otter Tail delivers energy. The sales forecast data, along with forward energy and fuel pricing forecasts, are then used to develop the generation and fuel costs forecast. The generation and fuel costs forecast includes steam generation, steam plant reagents, internal combustion, wind generation, solar generation, hydro generation, purchased power, and asset-based sales. Following the development of the generation and fuel costs forecast, the non-energy wholesale market charges, wind curtailment, steam and water sales, and Hoot Lake Solar generation credit forecasts are developed. Data from the above listed forecasts are then used to calculate the monthly cost per kilowatt-hour (kWh) forecast. Calculations of the monthly cost per kWh are shown in Attachment 2.

C. Description of Sales Forecast

Attachment 6 provides a summary of the sales forecast used in calculating Otter Tail's 2025 EAR rates. The sales forecast includes system retail kWh sales of 5,882,383,365 kWh and forecasted sales to four municipalities of 2,994,511 kWh. The total of these two amounts equals 2025 forecasted sales, 5,885,377,876 kWh (provided as MWh in Table 2 above). Otter Tail provides a description of Attachment 6 in subparts *1* and *2* of this section below.

1. System Sales Forecast

Otter Tail develops its sales forecast using econometric models. Otter Tail uses standard ordinary least squares (OLS) regression models. The purpose of these models is to estimate the relationship between a dependent variable and independent variables (e.g., heating degree days, or Gross Regional Product). These econometric models forecast the average use-per-meter and the number of meters for each customer class using historical sales data and historical number of meters, economic activity, and weather conditions as primary independent variables. The Large Commercial class is forecasted slightly differently, using kWh sales instead of use-per-meter and number of meters. Month-specific variables are also used to capture any seasonal patterns that are not related to the other independent variables. For all classes except Large Commercial, monthly sales forecasts are developed by multiplying use-per-meter forecasts by number of meter forecasts for each customer class and jurisdiction. Summing the various jurisdictional class forecasts yields the total system sales forecast.

The econometric techniques utilize 20 years of historical data (2004 through 2023) to produce estimated effects of weather, economic factors, and demographic factors on class usage. Forecast values for the independent values (derived from Woods and Poole economic forecasts or based on weather normal conditions) are then inserted into the equations to produce forecast values of class-level sales. Attachment 6.a (Sales Forecast Description) provides further detail on the forecasting methodology used in the 2025 sales forecast. One notable change from historic sales is a substantial increase in forecasted North Dakota sales due to recent load growth in Otter Tail's North Dakota jurisdiction. Otter Tail continues to use 55 heating degree days (HDD) in this forecast as Otter Tail believes it is a more appropriate metric than 65 HDD for Otter Tail's load.

2. Municipal Sales Forecast

As noted above, Otter Tail delivers energy on a wholesale basis to four municipalities. The four municipalities are Newfolden, MN; Shelly, MN; Nielsville, MN; and Badger, SD. The municipality forecasts, which do not vary much, are developed based on historical information using the average kWh sales of the prior two years. This forecast is provided in Attachment 6.

D. Description of Forecast Modeling Software, Fuel, Purchased Power Costs, and other Costs recoverable through the EAR

In subparts *1*. through *6*. below, Otter Tail provides a description of the modeling software, EnCompass, as well as reviews the various fuel and purchased power costs applicable to the EAR. Subparts *7.–9*. reviews reagent expenses, revenues, and costs associated with steam sales, and a credit resulting from Hoot Lake Solar generation, respectively.

1. Overview of EnCompass Modeling Software

Otter Tail uses EnCompass (resource planning modeling software) to perform the majority of the generation fuel, purchased power, and asset-based sales forecasting. EnCompass performs full year, 8,760[3] hourly modeling which includes operating parameters for generating units and uses the sales forecast (described in *Section C* above) as the basis to determine the energy requirements for Otter Tail's system.

The EnCompass model performs an economic dispatch of available resources to meet energy requirements, taking into account operational specifications and performance parameters of existing thermal resources (heat rates, maintenance schedules, forced outage rates, minimum/maximum capabilities), hydro units, owned wind and solar, and power purchase agreements. Price forecasts for oil, coal, and natural gas, as well as forecasted locational marginal prices (LMPs) for the Otter Tail load zone (OTP.OTP) are used as key inputs into EnCompass. There are also 'shapes' or 'profiles' for retail sales, energy prices, and renewable generation used in EnCompass that determine retail sales and economic dispatch.

The results of the EnCompass economic dispatch forecast is included in Attachment 3.1 to this filing. Attachment 3.1 includes the MWh and fuel costs associated with generating electricity at our steam and internal combustion (peaking & natural gas) generation plants based on the forecasted dispatch of those plants, as well as wind, solar, and hydro generation, purchased power costs, and asset-based sales.

2. Overview of Generation Types and Associated Costs

a. Steam Generation

i. Operational Parameters

In April of 2020, the owners of Big Stone Plant agreed to a methodology to allow the operation of Big Stone Plant to be offered

[3] 24 hours per day by 365 days per year.

into the Midcontinent Independent System Operation (MISO)/Southwest Power Pool (SPP) markets on an economic dispatch basis. This methodology includes weekly, bi-weekly, or as-needed meetings with all Co-Owners (Otter Tail Power Company, Montana-Dakota Utilities Co., and NorthWestern Energy) to review the economic dispatch or self-commitment status of Big Stone Plant. In this 2025 forecast for Big Stone Plant, the EnCompass modeling reflects self-commitment at minimum output, while allowing for market driven dispatch above minimums, for **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Please note, all Big Stone Plant Co-Owners maintain the contractual right to request the plant to be self-committed for any reason.

Otter Tail is a Co-Owner of Coyote Station with Minnkota Power Cooperative, Montana-Dakota Utilities Co., and Northwestern Energy. In April of 2021, the Co-Owners of Coyote Station developed and implemented capability to offer the plant under an economic offer. As with Big Stone Plant, each Coyote Co-Owner maintains the contractual right to request self-commitment. For Coyote Station, the EnCompass modeling reflects self-commitment at minimum output, while allowing for market driven dispatch above minimums for **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Otter Tail will continue to monitor the commitment of the plant and adjust appropriately to reflect plant operations in future forecasts.

ii. Fuel Supply

Steam plant costs are related to coal and fuel oil costs for our Big Stone Plant and Coyote Station. A large factor in determining the economic dispatch of the steam generation plants is the forecasted Locational Marginal Price (LMP) for the OTP.OTP load zone. Otter Tail calculates forward day ahead OTP.OTP load zone pricing using forward, day ahead Indiana Hub pricing (both monthly peak and monthly off peak) and including a basis adjustment from Indiana Hub to the OTP.OTP load zone. Based on historical deltas between the OTP.OTP load zone and the Indiana hub, Otter Tail forecasts a future basis to predict forward pricing at OTP.OTP. Otter Tail acquires forward day ahead Indiana Hub pricing from the Intercontinental Exchange (ICE) website.[4] ICE is a subscription-based trading platform that offers historical, current, and forward pricing information for numerous commodities including energy, natural gas, and oil. The 2025 forecast was based on the forward, day ahead Indiana Hub price curve dated March 28, 2024. Otter Tail provides this information in Attachment 7.

Otter Tail has several coal contracts in place to maintain low coal costs for its coal burning generating facilities. The primary coal supply agreements are listed in Table 4 below.

Table 4 – Primary Coal Supply Agreements

	(A)	(B)	(C)	(D)
Line No.	**Plant**	**Coal Supplier**	**Type of Coal**	**Expiration Date**
1	Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2024
2	Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040

Otter Tail entered into the current coal purchase agreement with Peabody COALSALES, LLC in May 2022 for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2024. Otter Tail has no fixed minimum purchase requirements under this agreement but Big Stone Plant's coal requirements for the period covered must be wholly purchased under this agreement. At the time of this filing, Otter Tail has not executed a Big Stone coal contract for 2025 coal requirements and includes an estimate based on the best available data at this time. Otter Tail is utilizing a competitive bidding process for 2025 Big Stone Plant coal requirements.

[4] ICE website: https://www.theice.com/index.

In October 2012, the Coyote Station owners, including Otter Tail, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton being paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. The LSA provides for the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and at the end of the term of the LSA.

Coyote Station is looking to test a fuel additive that has the potential to improve boiler efficiency by reducing the buildup of slag in the boiler. If the test proves to be successful, Coyote Station may implement the use of this fuel additive after the test. The fuel additive is added at an equivalent rate of about $1/ton of fuel, and therefore the usage rate could cost about $58,000 /month OTP total. The cost of the pilot test is not included in this filing. Otter Tail will provide the Commission an update of the results of this pilot and will seek cost recovery of the costs in its next FCA True-up filing.

iii. Planned and Forced Outages

Planned and forced outages of Otter Tail's coal generation plants is another key factor that impacts the forecast. Planned outages and overhauls are determined by the length of service between them. Based on operating history, plant personnel have a good understanding of the length of time between operational periods before the boiler or other systems will need to be cleaned or maintained while off-line. Larger scheduled outages, referred to at times as overhauls, are scheduled in approximately three-year intervals or when significant outages are needed for certain projects. Table 5 below summarizes Otter Tail's planned plant outages for Big Stone Plant and Coyote Station in 2025.

Table 5 – Otter Tail Plant 2025 Planned Outages

	(A)	(B)	(C)	(D)
Line No.	**Outage Start**	**Outage End**	**Plant**	**Duration & Type**
[PROTECTED DATA BEGINS...				

...PROTECTED DATA ENDS]

Plant outages, whether planned or unplanned, have an impact on Otter Tail's expected FCA-related costs. These impacts are generally the difference between the costs of generation at one of Otter Tail's owned facilities and purchasing energy supply in some way in the market. Estimated planned outage cost in the forecast was determined with a modeling run removing the planned outage variables from the EnCompass base case model scenario. The resulting difference between the base case EnCompass run and removing the planned outage variables was **[PROTECTED DATA BEGINS...**
...PROTECTED DATA ENDS]. This signifies that the cost of purchasing in the market is higher than generating at the plant. Otter Tail plans outages to best minimize added costs of energy and typically schedules these outages in the spring or fall when energy usage is generally lowest.

The forecast also includes forced outage rates for each plant based on six years of historical data. Otter Tail used a six-year average (2018 to 2023) Equivalent Demand Forced Outage Rate for each plant as the forced outage input in the forecast. Forced outage rates are included in the forecast to reasonably account for and protect customers and Otter Tail from the inevitability of unplanned outages and the effect on rates as a result of the outage. The estimated forced outage costs in the forecast were determined similarly to how planned outage costs were calculated. Forced outage rates for each of the thermal plants was removed from the base case and the EnCompass model was run. The difference between the base case EnCompass run and the run which reflected removing the forced outage rates of all thermal plants was **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**.

b. Internal Combustion

Internal combustion plant costs are related to fuel oil costs for Otter Tail's Jamestown #1 and #2 and Lake Preston peaking plants; and natural gas fuel costs for Otter Tail's Solway and Astoria Station natural gas-fired peaking plants.

Fuel oil costs are forecasted based on a Wood-Mackenzie fuel oil forecast. The forecasted fuel oil cost used in the 2025 forecast is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** per gallon.

Fuel cost and forecasted output from Astoria Station is a major variable and assumption in this forecast. Astoria's operational timing, and ability to provide economical and dispatchable energy, will have a large impact on our natural gas fuel costs. Natural gas prices play a vital role in the economic dispatch and costs associated with Astoria Station and Solway. At the same time, due to uncertainty with regard to the amount of dispatch of these plants, Otter Tail generally procures gas for its Solway and Astoria on a day-ahead or intra-day basis.

Like forward energy pricing described earlier, Otter Tail acquires forward natural gas pricing curves from the ICE website. Ventura hub, located in northern Iowa, is the most liquid natural gas trading hub in our region. Daily, ICE posts forward natural gas price curves for Ventura hub. For forecasting purposes, Otter Tail uses the forward Ventura curve for both Solway and Astoria. For this forecast, Otter Tail used the forward natural gas price curve dated March 28, 2024. This information is provided in Attachment 8 to this filing.

Astoria Station is located on the Northern Border Pipeline. Unlike the Great Lakes Pipeline, where Otter Tail's existing Solway plant is located, the Northern Border Pipeline has higher requirements and tighter tolerances for balancing daily nominations and withdrawals of gas. Due to the highly variable and intermittent nature of a simple cycle gas turbine, differences between the gas and electric trading days, and changes between the MISO day ahead forecast and actual real time operations, Otter Tail determined it prudent to secure Park and Loan (PAL) service for its natural gas supply. PAL is the Northern Border Pipeline balancing service. This service allows an entity to "park" excess gas in the pipe to be consumed later, or to "loan" gas from the pipe to be replaced later. The PAL service procured by Otter Tail allows for additional supply availability, enhanced operational flexibility, and enables Astoria to better operate within required Northern Border operating tolerances.

2025 Astoria PAL service levels allow for a **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS] The PAL service costs are included in the forecast.

c. Wind Generation

Otter Tail has a significant portfolio of wind generation, both from an owned-wind perspective and from wind purchase power agreements. Otter Tail's owned wind generation contributes to the energy output for Otter Tail's generation system but there are no fuel costs associated with Otter Tail's owned wind generation. Otter Tail's existing owned wind generation fleet consists of the Merricourt (150 MWs), Langdon (40.5 MWs), Ashtabula (48 MWs), Ashtabula III (62.4 MWs) and Luverne (49.5 MWs) wind energy facilities. The generation output from the Langdon, Ashtabula, Ashtabula III, and Luverne wind farms are forecasted based on an hourly generation profile that reflects the average historical performance of each facility. Merricourt is forecasted based on a forward-looking hourly generation profile that reflects Otter Tail's expectations of the facility's performance.

For 2024, Otter Tail forecasts Merricourt output to be about [**PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. As with Astoria, Merricourt is also a relatively new resource. As a result, there is additional dispatch uncertainty compared to Otter Tail's other wind facilities. It is reasonable to assume that actual dispatch will vary from the forecasted values.

d. Hydro Generation

Like wind generation, hydro generation also contributes to the energy output for Otter Tail's generation system, but Otter Tail has no fuel costs from hydro generation. Hydro generation is sourced from the following facilities: Dayton Hollow, Hoot Lake, Pisgah, Taplin Gorge (Friberg), and Wright

(Central). Generation for our hydro plants is forecasted using historical averages and the generation is included in Attachment 3.1, Line 37.

e. Solar Generation

Otter Tail completed the construction of our 49.9 MW Hoot Lake Solar project in August of 2023, near Fergus Falls, Minnesota. This project provides zero fuel cost energy output for Otter Tail's generation system. At the Commission's March 25, 2021 meeting in Docket No. E017/M-20-844,[5] the Commission approved Otter Tail's request to fully allocate to Minnesota the output and costs of the Hoot Lake Solar project. Subpart *9.*, below, describes Otter Tail's previously approved methodology (from a forecast perspective) to fully allocate the zero-fuel cost output from Hoot Lake Solar to Minnesota customers.

Otter Tail also completed two smaller solar projects in 2020: Blue Jay Solar in Jamestown, North Dakota, and Blue Heron Solar near Otter Tail, Minnesota. Each of these facilities are approximately 40-kilowatts (kW) in capacity. Otter Tail includes these in the small co-generation line on Attachment 3.1 for forecasting purposes. Small co-generation is described further below.

3. Purchased Power

As a member of MISO, each day Otter Tail offers all its available generation into the MISO market and acquires all its energy from the MISO market. From a cost of energy perspective, the proceeds from the sale of Otter Tail's generation into the market offsets costs associated with energy withdrawals for load. In instances where Otter Tail load is greater than Otter Tail's combined dispatched generation and existing purchased power amounts, Otter Tail procures the remaining energy from the market. Forecasted market purchases are determined using the EnCompass model to project hourly economic dispatch of generation where the forecasted hourly market prices are compared to the marginal cost of Otter Tail's thermal units. If the hourly market price is less than the marginal cost of Otter Tail's units, an hourly market purchase is made (subject to self-commitment and minimum run restrictions on the thermal units).

In addition to purchases from the MISO market, purchased power costs also include energy purchases from our Edgeley (21 MWs) and Langdon (19.5 MWs) Wind Purchased Power Agreements (PPAs). Otter Tail also acquires energy from

[5] In the Matter of Otter Tail power Company's Petition for Approval of the Hoot Lake Solar Project.

shared loads, small co-generation,[6] and bilateral purchases. These are provided in detail in Attachment 3.1, Lines 92-98, excluding Line 94.[7] The costs for these PPAs are set forth in the PPAs as a price per MWh for all output. The generation output of the PPA facilities is forecasted using an hourly generation profile that reflects the average historical performance of each facility.

For the 2025 operating year, Otter Tail also procured a winter energy purchase delivered to the OTP.OTP load zone. This purchase is detailed in Table 6 below and is embedded in Attachment 3.1, Line 97, Bilateral Purchases.

Table 6
2025 Winter Energy Purchase

Time Frame	MWs	Price ($ per MWh)
[PROTECTED DATA BEGINS…		
		…PROTECTED DATA ENDS]

This energy purchase was procured to hedge Otter Tail customers against the historic volatility of energy markets primarily driven by natural gas pricing during the winter months (December, January, February) and their corresponding impacts on energy prices. Under existing market conditions, the price of natural gas is a large driver in energy market pricing.

The forward energy hedge purchase provides the benefit of price certainty at the OTP.OTP load zone. This purchase benefited from a competitive energy market where multiple parties provided competitive offers. Ultimately, this purchase will be fulfilled by the MISO market, and Otter Tail will be made financially whole to the above stated contract price with the counterparty under a contract for differences (CFD) arrangement.

[6] Due to small size, these Small Co-Generation purchased agreements are modeled as a group for forecasting. These agreements are less than 20MW, generally under 2MW, wind or solar related, and Otter Tail provides these as a group for forecasting purposes. Otter Tail will provide details for actuals.
[7] Attachment 3, Line 100 is for Tribal (WAPA)-related energy purchases which are not subject to the FCA.

4. Fuel Costs of Asset-Based Sales and MN Asset-Based Margins

In certain situations, Otter Tail may sell more energy into the market from its generation fleet than what Otter Tail needs to serve its own load. In these situations, any asset-based margins that are realized are credited to the EAR rate calculation. Asset-based margins are the net difference between asset-based sales and the fuel cost of sales associated with asset-based sales. Similar to market purchases, forecasted asset-based sales are derived from the hourly economic dispatch where the hourly market prices are compared to the marginal cost of Otter Tail's thermal units (that are running to meet customer load). If the hourly market price is more than the marginal cost of Otter Tail's units (and the unit generation is not needed to meet customer need), Otter Tail's unit is assumed to be dispatched and an hourly asset-based sale is made. Forecasted fuel costs of asset-based sales and asset-based margins are included on Attachment 3.1, Lines 103 and 104, respectively.

5. Wind Curtailment

On occasion, when there is an abundance of energy available to the market relative to demand for energy, hourly LMP prices at generators can become negative. In those situations, the generator pays for (as opposed to being paid for) the generation sold into the market. To avoid having to pay the negative LMP price, wind generating facilities are sometimes taken offline. Some of Otter Tail's wind PPAs have curtailment payment provisions included in the agreement. These payments offset a portion of the lost production the generator realizes when the units are taken offline.

Otter Tail's 2025 monthly forecasted wind curtailment MWhs were developed using the monthly average of the available actual wind curtailment MWhs for the wind PPAs subject to wind curtailment. Forecasted wind curtailment costs were then determined by multiplying the forecasted monthly MWhs by the 2025 blended forecasted annual average cost per MWh of Otter Tail's wind PPAs subject to wind curtailment.

[PROTECTED DATA BEGINS...

.

...PROTECTED DATA ENDS] The forecasted wind curtailment cost calculation is included in Attachment 5.

6. Wholesale Market Charges

Forecasted wholesale market charges consist of numerous charges and credits Otter Tail is subjected to as a participant in the MISO and the SPP energy markets. This subset of wholesale market charges/credits does not include the primary charges/credits associated with the injection of energy (generation) and the withdrawal of energy (load), as these charges are captured in other sections of this forecast.

Approximately 70 MISO and SPP wholesale market charge types are included in this forecast. Each charge type is forecasted individually. Varying forecasting methods such as averaging, application of calculated historical rates, and scaling to meet forecasted loads are the primary methods employed to forecast the different charge types noted above. All forecasting methods are based on historical data and future projections. For historical data, Otter Tail used the most recent 24 months of available data, which included April of 2022 through March of 2024.

In some cases, Otter Tail has chosen to customize certain charge type forecasts to account for known, and unique, historical events and market conditions.

The individual charge types are categorized into three base tables/categories: MISO Wholesale Market Charges (Non-Energy); MISO Ancillary Services Market (ASM) Market Charges; and SPP Wholesale Market Charges (Non-Energy). A description of each category is provided below.

- MISO Wholesale Market Charges (Non-Energy): This category forecasts numerous, miscellaneous MISO wholesale charges and credits including uplift charges, make whole payments, financial transmission rights charges and credits, real time miscellaneous charges, etc. This summary also includes forecasting for net congestion and net loss charges and credits. These are charges and costs associated with moving energy from Otter Tail generation resources to Otter Tail load. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.1 to this filing.

  For completeness, forecasted amounts are provided for the Day Ahead Market Admin, Real Time Market Admin, and FTR Market Admin (Schedules 16 and 17) charge types (Attachment 4.1, Line 18). However, these amounts are not included in the 2025 FCA calculation, as they are currently recovered in Otter Tail's base rates. Total Forecasted MISO

Wholesale Charges (Attachment 4.1, Line 61) does not include these amounts. They are provided as informational only.

- SPP Wholesale Market Charges (Non-Energy): The primary drivers of the SPP wholesale market charges forecast are the Real-Time Over Collected Losses Distribution Amount, the Real-Time Pseudo-Tie Congestion Amount, the Real-Time Pseudo-Tie Loss Amount, the Auction revenue Rights Daily Amount, and the Auction Revenue Rights Annual Closeout Amount. These charge types are the result of Otter Tail's required SPP transmission service necessary to serve Otter Tail's pseudo tied load within the SPP footprint. This category also forecasts other numerous, miscellaneous SPP wholesale charges and credits. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.2 to this filing.

- MISO ASM Market Charges: This category forecasts MISO ASM charges and credits, including regulation reserves, spinning reserves, supplemental reserves, and short-term reserves, both withdrawn by Otter Tail load and produced by Otter Tail generation. It also includes other miscellaneous charges associated with the ASM market. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.3 to this filing.

7. Reagents

Otter Tail's coal-fired generation facilities, Big Stone Plant and Coyote Station, use substances called reagents to process emissions and are necessary for Otter Tail's compliance with federal regulations enforced by the Environmental Protection Agency. These reagents include anhydrous ammonia, pebble lime, and powder activated carbon. Forecasted reagent expenses are included on Attachment 3.1, Lines 110 to 125. Forecasted reagent expenses were determined using a forecasted cost per MWh for each applicable reagent and multiplying that by the forecasted output (MWh) of the applicable facility.

8. Costs and Revenues Associated with Steam/Water Sales

Otter Tail sells steam and water from its Big Stone Plant to a geographically adjacent, non-affiliated company. The 2025 forecasted steam/water sale expenses and revenues are included on Attachment 3.2, Lines 1-9. Steam/water sale expenses and revenues were forecasted by Big Stone Plant employees, who have the best knowledge and experience with the facility's steam sales. The revenue forecasts are derived from many factors, including: the customer's needs and forecasts provided by the customer, contractual agreements between Big Stone Plant and the customer, and Big Stone Plants forecasted operational output and ability to provide steam/water. The expense forecast is derived from the revenue forecast. The amount of coal burned is calculated based on the measured energy and boiler efficiency. Reagent amounts attributable to steam sales are determined in proportion to the forecasted coal burned. The amount of coal and reagents forecasted to be used, tons and/or lbs., is then multiplied by a forecasted $/ton or $/lb. to arrive at the forecasted costs.

9. Hoot Lake Solar Generation Credit

In Docket No. E017/M-20-844, the Commission approved Otter Tail's request to fully allocate to Minnesota the output and costs of the Hoot Lake Solar project. Otter Tail's current Minnesota EAR mechanism calculates Minnesota EAR rates based on total system costs divided by total system sales. Because Minnesota is not the only jurisdiction Otter Tail serves,[8] the impact of the zero-fuel cost output of Hoot Lake Solar is diluted amongst all customers in the three states Otter Tail serves. Minnesota customers will only receive approximately 45 percent of the benefit of lowered EAR rates from Hoot Lake Solar without modifications to the current mechanism. To address this, Otter Tail includes the previously approved calculation methodology as shown in Attachment 3.3. Attachment 3.3 calculates the estimated cost of avoided market purchases due to Hoot Lake Solar's output (Lines 1-5). The amount of avoided cost captured by Minnesota customers in the current mechanism, based on Minnesota sales as a percent of total sales, is calculated on Lines 8-13. Next, the amount of avoided cost not captured by Minnesota is calculated on line 15. Finally, that amount is "grossed up" to a Total System amount (Line 17) and credited to the EAR rate calculation at a system level in Attachment 2, Line 9.

From a forecasting perspective, Otter Tail uses the forecasted monthly cost per MWh of Market Purchases and the forecasted monthly output for Hoot Lake Solar to calculate the avoided cost. On a monthly actual basis, Otter Tail is able to obtain the actual revenue generated by Hoot Lake Solar through two primary MISO charge types, Day Ahead Asset Energy amount and Non-Excessive Energy Amount. The total actual revenue from Hoot Lake Solar replaces the forecasted amount on line 5 of Attachment 3.3 to calculate the actual amount of credit necessary to the MN EAR calculation. Values on lines 8 and 9 are also replaced with actual sales values.

[8] Otter Tail serves customers in Minnesota, North Dakota, and South Dakota.

10. MISO Planning Resource Auction Results

The Commission's Order dated December 29, 2022, in Docket No. E017/AA-22-214 required Otter Tail include actual known MISO Planning Resource Auction (PRA) costs and revenues in the EAR. The 2023/2024 planning year results were only $330k, of which the January to May 2024 revenues will be included in the 2024 recovery year True-up Filing. Results for the MISO June 2024/ May 2025 planning year auction will be known sometime in May 2024. Should the June to December 2024 results be material, Otter Tail will update its 2024 rates to include known (anticipated) revenues in the following month from when the results are known If results are immaterial, Otter Tail will include the 2024 portion of those revenues in the 2024 annual True-up Filing. The Commission waived the 30-day notice of a significant event filing for the inclusion of these costs and/or revenues.

No estimated PRA costs or revenues for the 2025 portion of the June 2024/May 2025 MISO planning year are included in this EAR forecast due to uncertainty in the ability to forecast those results. Once the Planning Year 2024/2025 results are known, if they are material, Otter Tail will include the 2025 portion of those results in the forecast and provide updated rates with our July 31, 2024 Reply Comments in this Docket.

E. Risks (Mitigation)

Otter Tail's supply resource portfolio is managed in a way to cost-effectively meet energy needs while maintaining flexibility and reasonably limiting the risk of exposure to variability in the availability of resources and the costs thereof. Some risk mitigation strategies include forward procurement of energy or fuel supplies, having a diverse owned generation supply (thermal, wind, solar, hydro), and having the ability to procure needed energy from the broader MISO market when necessary or when economically beneficial. Despite these strategies, there remains inherent risk between forecasted costs and actual costs that is either difficult or outside of the Company's control to manage.

Table 7 below identifies key variables or assumptions that could impact actual costs relative to forecasted costs which may have a five percent or greater impact on the fuel cost per kWh. Within the table, Otter Tail identifies the risk [Column A], a description of the risk [Column B], and potential impact on the fuel cost per kWh [Column C].

Table 7
Risk Matrix

Line No.	(A) Variable	(B) Risk	(C) Potential Impact on cost/kWh
1	Sales	Actual sales differ from forecasted sales.	Increases in sales may result in more reliance on market purchases – potentially at higher-than-average cost. Lower sales may reduce market purchases and lower average cost.
2	Weather	Weather drives usage higher or lower than forecasted	Colder or hotter weather than normal can increase demand for energy- may result in more purchases from the market.
3	Natural Gas Prices	Actual gas prices differ from forecasted prices. Generally, the cost of gas is procured on a short-term (day ahead) basis due to uncertainly of dispatch of Otter Tail's gas generation and limiting the ability to hedge price.	Otter Tail is exposed to price variances which could increase or decrease costs relative to forecast.
4	Locational Marginal Prices (Market Prices)	Actual prices differ from forecasted prices which impact both dispatch of generation and cost of purchases from the market.	Cost of market purchases could be higher or lower than forecasted.
5	Wind	The forecast includes a certain amount of wind generation for both Otter Tail's owned wind resources and for certain PPAs. Variance from the forecast will impact the cost of energy.	If our owned wind resource generation is less than forecasted, we will replace it with a resource that has a higher cost. If our owned wind generation is greater than forecasted, energy will be supplied at lower average cost. If our Wind PPAs do not produce as much energy as forecasted, the FCA-related cost per kWh could be higher or lower depending on the market purchase price comparison needed to replace the Wind PPA price.
6	Solar	The forecast includes a certain amount of solar generation. Variance from the forecast will impact the cost of energy.	If our owned solar resource generation is less than forecasted, we will replace it with a resource that has a higher cost. If our owned solar generation is greater than forecasted, energy will be supplied at lower average cost.

7	Market Purchases	Entering into PPAs creates price certainty and reduces rate volatility. Certainty of pricing comes at a premium cost. Otter Tail's supply portfolio is described throughout this Petition and includes an all-of-the-above strategy. Otter Tail relies on the market to supply a certain amount of energy for its customers. This approach exposes Otter Tail to potential volatility in the market but also helps us mitigate FCA-related costs.	Market prices may either be higher or lower than forecasted which will impact the overall fuel cost per kWh.
8	Unplanned Outages at Otter Tail Generating Facilities	Number of outages greater than forecasted could potentially increase exposure to market purchases.	Cost of additional market purchases could be higher or lower than cost of generation.
9	Freight Prices	The coal freight prices used for Big Stone Plant are based on current tariffed rates.	These rates can be adjusted by the railroad, affecting actual fuel cost per kwh.
10	Asset-Based Sales and Margins	The relation of market prices to the cost of Otter Tail's owned generation resources is different than forecasted and results in lower Asset-Based Sales and Margins than forecasted.	Creates less of a credit to the FCA calculation, increasing overall cost per kWh.

F. Annual Compliance/Reporting Requirements

In Appendix A to this filing, Otter Tail provides certain annual reporting requirements specified in the Rule sections described below to satisfy compliance obligations stemming from either these Rules or prior Commission Orders. Rule variances for these rules were approved by the Commission at a Commission Hearing on April 25, 2019,[9] to align with the new forecasting and true-up mechanisms, filing timings, and reporting requirements under this new process. Otter Tail's compliance with requirements ordered[10] in Docket No. E017/AA-19-297 is also discussed below.

Minn. R. 7825.2800 Annual Report: Policies and Actions

Appendix A Section 1 includes the following and a summary of the topics listed in the rule:

Section 1.1 Fuel Procurement Practices
Section 1.2 Fuel Utilization

[9] Order dated June 12, 2019, in Docket No. E-999/CI-03-802.
[10] Order Approving 2020 Fuel Forecasts dated December 18, 2019.

Section 1.3 Procurement of Transportation Services

Minn. R. 7825.2810 Annual Report: Automatic Adjustment of Charges

Appendix A Section 2 contains a summary of the annual reporting (by month) of all forecasted electric automatic adjustment charges for the forecast period January 1, 2024, to December 31, 2024. It includes the following:

Appendix A Section 2 Subpt. 1.A. Commission Approved Base Cost of Fuel
Appendix A Section 2.1 Subpt. 1.D. Total Cost of Fuel Delivered to Customers

Additional Reporting Requirements

Additional Reporting Requirements as Ordered by the Commission are also provided in Appendix A in the following sections:

Appendix A Section 3	Passing MISO Day 2 Costs Through Fuel Clause Order in Docket No. E017/M-05-284
Appendix A Section 4	Southwest Power Pool (SPP) Energy Market Related Costs – Order in Docket No. E017/GR-15-1033
Appendix A Section 5	MN DOC'S Review of 2005/2006 AAA Report Docket No. E,G999/AA-06-1208
Appendix A Section 6	MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS DOCKET NOS. E999/AA-09-961 and E999/AA-10-884
Appendix A Section 7	MN OES'S Review of 2006/2007 AAA Report Docket No. E,G999/AA-07-1130

Minn. R. 7825.2830 Annual Five-Year Projection

Attachment 11 contains a monthly five-year projection of fuel cost by energy source marked as Not Public.

Minn. R. 7825.2840 Notice of Reports Availability

Appendix B contains the Notice of Reports Availability, Certificate of Service, and Service Lists.

Additional Requirements Ordered December 18, 2019, in Docket No. E017/AA-19-297

Order Point 2 – Otter Tail shall identify any and all variables for which Otter Tail's Strategist run outcome would be inconsistent with the historical data of the variable and describe and justify any and all steps used to address the inconsistency issue(s).

Most variables/inputs in Otter Tail's EnCompass modeling are consistent with historical data of the variable. The inputs which vary from historic data are provided below. All the variances are the result of known and measurable changes or reasonably anticipated changes provided from reliable resources Otter Tail uses in its forecasting (i.e., Wood-Mackenzie forecasts, Intercontinental Exchange (ICE) trading platform forecasts, Woods and Poole economic forecasts, etc.

- <u>Otter Tail's forecasted owned-solar generation:</u> Hoot Lake Solar was deemed commercially operational in August of 2023.
- <u>Forecasted LMP and Natural Gas Energy Pricing:</u> Forecasted LMP and Natural Gas prices are significantly higher than recent years but lower than last year. Otter Tail has used the most recent forecasts available for this forecast. This has resulted in an eight percent decrease in forecasted Otter Tail Internal Combustion generation.
- <u>Asset-based sales:</u> The 2025 forecasted asset-based sales are higher than historical asset-based sales due to the interdependent relationship of all the 2025 EnCompass model inputs and was the result of the EnCompass model determining there were more instances where an asset-based sale would be made in this 2025 forecast compared to recent history. The 2025 forecasted asset-based sales amount of $8.4 million.
- <u>Steam Plant Reagents and Steam/Water Sales:</u> As mentioned previously, Otter Tail includes forecasted steam plant reagent expenses and steam/water sales in this forecast reflective of the Commission's approval in the 2020 Rate Case.

The items listed above, along with all other EnCompass inputs/variables identified earlier in this Petition, results in overall increased Otter Tail-owned Steam generation output, decreased Purchased Power, increased Wind/Solar generation output, and increased Internal Combustion MWh for 2025 compared to recent history. The 2025 EnCompass forecast modeling results are consistent with what Otter Tail expects to occur as its served load and generation resource fleet continues to evolve.

Order Point 3 – Otter Tail shall provide as public data the historical system sales and their breakdown by customer class, except for classes for which private customer usage could be derived.

The sales forecast data included in Attachment 6 to this filing is public data. Otter Tail has aggregated individual large customer data into the appropriate customer classes to prevent private, customer usage from being derived. Total forecasted sales of the four municipalities are provided as public data in Attachment 6; however, sales specific to each municipality is protected.

Order Point 4 – Otter Tail shall provide as public data the total historical net system FCA costs, including their breakdown by major components.

Total forecasted net system FCA costs and their breakdown by major component are included as public data in Attachment 2. Otter Tail has two coal-fired generation facilities, Big Stone Plant and Coyote Station. To prevent disclosure of individual, private, plant data, especially when one of those generating facilities has a forecasted planned outage, the highest level of monthly data granularity Otter Tail can provide as public data in Attachment 3.1 is to the Total OTP-Owned level. Annual totals for the major components are provided as public data.

Order Point 5 – Otter Tail shall update its 2010 internal line losses study and incorporate that information into the 2021 Forecast.

This compliance obligation was satisfied in the 2021 MN FCA Forecast Filing, which was approved by the December 2020 Order. Otter Tail updated its line losses study and incorporated the results into the 2021 MN FCA Forecast. These updated parameters have been included in subsequent FCA forecasts.

Order Point 6 - The variance to Minn. Rules 7825.2840 is revised as follows: By September 1 of each year, gas utilities and by March 1 and May 1 of each year, electric utilities shall provide notice of availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the previous two general rate cases.

Otter Tail has included all intervenors from its previous two Minnesota general rate cases (Docket No. E017/GR-15-1033 and E017/GR-20-719) in the notice of availability of reports.

Additional Requirements Ordered March 12, 2024 in Docket No. E-999/CI-03-802

Order Point 2 – In their future Fuel Clause Adjustment filings, the three utilities shall incorporate –

A. Answers to recurring information requests, including the most recent three-year average of actual annual data compared to the forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages; and

B. A comparison of the actual winter energy purchase amounts to the forecast amounts, with an explanation of a variance of five percent or greater.

Attachment 12 contains the most recent three-year average of actual annual data compared to the forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales to comply with Order Point 2.A. and is marked as Not Public.

Attachment 13 provided the most recent three-year average of actual annual data compared to the forecast for the FCA calculation of outages in compliance with Order Point 2.A. The 2025 forecast Forced Outage Rate inputs for Big Stone Plant and Coyote Station (8.9 percent and 11.0 percent, respectively) are different than the previous three years, 2021-2023 EFORd rates and corresponding outage MWh.

EFORD (Force Outage Rate)	Big Stone Plant	Coyote Station
2018	3.5	9.4
2019	0.9	19.4
2020	1.7	8.2
2021	13.0	10.7
2022	18.7	11.2
2023	15.5	6.9
2025F (2018-2023 Average)	**8.9**	**11.0**

The greater than 5 percent variance when comparing the 2024 forecasted MWh of forced outages to the 2020-2022 three-year average and the 2022 actual outages is the large range of outage MWh for each plant in 2020-2022, which influences the three-year average. Beginning November 2022, Big Stone Plant experienced a 56.3-day unplanned outage due to bearing #7 vibration/exciter causing a higher EFORd rate for Big Stone Plant in 2022.The 2025 forecast forced outage rate inputs used in this filing for Big Stone Plant falls between the lowest and second highest EFORd rate among years 2020-2022 while Coyote is higher than that same time frame. Similarly, the 2025 forecasted outage MWh also falls along that same premise for each plant for outage MWh among years 2020-2022. Given this similar correlation, the 2025 forecasted outage MWh are reasonable based on the inputs used and previous years actuals.

Attachment 14 provides a comparison of the actual winter energy purchase amounts to the forecast amounts to comply with Order Point 2.B. and is marked as Not Public. The volume and associated costs of forward purchases increased in 2022 relative to 2021. Factors contributing to the increased volume of forward purchases in 2022 included increased loads, planned and forced outages at Big Stone Plant in late 2022, as well as the transition in Otter Tail's generation fleet with the retirement of Otter Tail's Hoot Lake Plant in May 2021, the addition of the Merricourt wind energy center, and the addition of the Astoria Station simple cycle natural gas plant. Previously, Hoot Lake Plant's cost of fuel (coal) was not subject to price volatilities that are seen at natural gas generating units. As a result, the retirement of the Hoot Lake Plant resulted in additional forward energy hedge purchases. In 2022, Otter Tail increased purchase volumes in both the peak and off-peak periods compared to 2021, which previously did not require any off-peak purchases in January or February.

Furthermore, in December 2022, Otter Tail made additional forward purchases for the second half of December 2022 and the month of January 2023 in anticipation of winter storm Elliot. At that time loads were anticipated to be high and Big Stone Plant was not available due to an extended excitor forced outage. There were concerns about significant price spikes in both the natural gas and LMP markets and a desire to not be exposed to a potential event like Winter Storm Uri which occurred in February 2021. Of the **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS].

Total forecasted MWhs of forward purchases in 2024 and 2025 are reduced from the 2021-2023 average levels as these purchases are based on forecasts that assume normal plant availability and average weather assumptions. The historical purchase in the winter of 2022/23, which accounted for Winter Storm Elliot, combined with the extended Big Stone exciter forced outage, does not have an equivalent purchase in the 2024 and 2025 forecasts. The average cost per MWh in 2025 has increased relative to the 2021- 2023 average. This cost increase is tied directly to forward energy market pricing at the time of the forward purchases.

The 2024 and 2025 forecasts consist of already completed and confirmed forward energy purchases. Assuming Otter Tail does not make additional forward energy purchases for these time periods, the existing forecasted values will become future actual values. Otter Tail provides Attachments 14.1-14.6, which are protected in their entirety. Attachments 14.1-14.6 contain the trade confirmations from the 2025 energy purchases.

V. ALLOCATIONS AND RATE DESIGN

Attachment 2 summarizes the forecasted costs and sales applicable to the MN FCA that are detailed in Attachments 3.1 through 6. Lines 1 through 11 of Attachment 2 provides the costs/credits applicable to the MN FCA and Line 15 provides the sales applicable to the MN FCA rate calculation. Line 17 provides the forecast Cost per kWh (Line 13/ Line 15).

Each customer class is assessed a class specific Energy Adjustment Factor (EAF) monthly rate, which is calculated by multiplying the forecasted monthly EAR rate by the applicable EAF ratio listed on page 2 of Otter Tail's Electric Rate Schedule Section 13.01. Class specific EAF rates are calculated in Attachment 1.

Proposed Rates by Service Category

In this filing, Otter Tail requests the Commission approve its total cost of energy upon which to develop rates, detailed in Attachment 2. Otter Tail also provides Attachment 1, which reflects the current approved 13.01 tariff mechanism. Attachment 1 calculates the class specific EAF rates and contains the following components: Service Category [Column A], Section [Column B], EAF Ratio [Column C], and the forecasted monthly EAF rates for each service category with the appropriate E8760 EAF ratio applied [Columns D through O].

VI. ENERGY ADJUSTMENT RIDER RATE SCHEDULE

A non-redline version of Otter Tail's current EAR Rate Schedule, Section 13.01, is included as Attachment 9 to this Petition. This schedule was approved by the Commission's November 9, 2023, Order in Otter Tail's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01, filed last year on May 1, 2023.[11] Otter Tail requests no changes to this Rate Schedule in this Docket.

VII. CUSTOMER NOTIFICATION

Attachment 10 is the proposed notice to customers that will be included with customer bills the month after the new EAR rates are approved. Once approved, these rates will be posted on Otter Tail's website.[12]

VIII. CONCLUSION

Otter Tail respectfully requests that the Commission approve the following:

1) The 2025 System Cost Energy Forecast of $23.920 per MWh.
2) Implementation of the forecasted 2025 EAR rates as listed in Attachment 1.

---

[11] Minnesota Docket No. E017/AA-23-181.
[12] https://www.otpco.com/pricing/minnesota/resource-adjustment-mn/.

Dated: May 1, 2024

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: */s/ Chris Byrnes*

Chris Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8282
cbyrnes@otpco.com

OTTER TAIL POWER COMPANY
FUEL CLAUSE ADJUSTMENT FORECAST PETITION ATTACHMENTS

Attachment 1	Proposed Monthly EAR Rates by Service Category
Attachment 2	Minnesota EAR Rate Calculation
Attachment 3.1	Generation and Fuel Forecast (Not Public)
Attachment 3.2	Steam and Water Sales (Not Public)
Attachment 3.3	Hoot Lake Solar Generation Credit (Not Public)
Attachment 4.1	MISO Wholesale Market Charges Forecast
Attachment 4.2	SPP Wholesale Market Charges Forecast
Attachment 4.3	MISO ASM Market Charges Forecast
Attachment 5	Wind Curtailment Forecast
Attachment 6	System Sales and Municipal Forecast (Not Public
Attachment 6.a	System Sales Forecast Description
Attachment 7	Intercontinental Exchange Local Marginal Price Forecast
Attachment 8	Intercontinental Exchange Natural Gas Price Forecast
Attachment 9	Energy Adjustment Rider Rate Schedule 13.01
Attachment 10	Customer Notification
Attachment 11	Rule 7825.2830 Annual Five-year Projection 2024-2028 (Not Public)
Attachment 12	2021-2023 Actuals Compared to 2025 Forecast (Not Public)
Attachment 13	Unplanned Outages Actuals to Forecast (Not Public)
Attachment 14	2021-2023 Bilateral Purchase Actual to Forecast (Not Public)
Appendix A	Compliance Items (Not Public)
Appendix B	Notice of Report Availability

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 PROPOSED FORECASTED EAR RATES

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	**Description**	**Section (2)**	**EAF Ratio (2)**	**January-25**	**February-25**	**March-25**	**April-25**	**May-25**	**June-25**	**July-25**	**August-25**	**September-25**	**October-25**	**November-25**	**December-25**
1	Proposed Cost per kWh - Attachment 2 (Line 17)			$ 0.02713	$ 0.02827	$ 0.02277	$ 0.02417	$ 0.02314	$ 0.02005	$ 0.02007	$ 0.02118	$ 0.02225	$ 0.02183	$ 0.02398	$ 0.02885
2	2022 True-up Factor (1)			$ 0.00200	$ 0.00200	$ 0.00200	$ 0.00200	$ 0.00200	$ 0.00200	$ 0.00200	$ 0.00200	$ -	$ -	$ -	$ -
3	2023 Supplemental True-up Factor (1)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	2023 True-up Factor			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -				
5	EAR Rates with True-up			**$ 0.02913**	**$ 0.03027**	**$ 0.02477**	**$ 0.02617**	**$ 0.02514**	**$ 0.02205**	**$ 0.02207**	**$ 0.02318**	**$ 0.02225**	**$ 0.02183**	**$ 0.02398**	**$ 0.02885**
6															
7															
8															
9	Residential	9.01, 9.02	1.0555	$ 0.03075	$ 0.03195	$ 0.02614	$ 0.02762	$ 0.02653	$ 0.02328	$ 0.02329	$ 0.02447	$ 0.02349	$ 0.02305	$ 0.02531	$ 0.03046
10	Farms	9.03	1.0281	$ 0.02995	$ 0.03112	$ 0.02546	$ 0.02690	$ 0.02584	$ 0.02267	$ 0.02269	$ 0.02383	$ 0.02288	$ 0.02245	$ 0.02465	$ 0.02967
11	General Service	10.01, 10.02, 10.03, 10.07	1.0461	$ 0.03048	$ 0.03166	$ 0.02591	$ 0.02737	$ 0.02629	$ 0.02307	$ 0.02308	$ 0.02425	$ 0.02328	$ 0.02284	$ 0.02508	$ 0.03018
12	Large General Service	10.04, 10.06, 11.01, 14.03	1.0207	$ 0.02974	$ 0.03089	$ 0.02528	$ 0.02671	$ 0.02566	$ 0.02251	$ 0.02252	$ 0.02366	$ 0.02272	$ 0.02229	$ 0.02447	$ 0.02945
13	Large General Service - TOD - Winter On-Peak	10.05, 10.06	1.2673	$ 0.03692	$ 0.03836	$ 0.03139	$ 0.03316	$ 0.03185					$ 0.02767	$ 0.03039	$ 0.03657
14	Large General Service - TOD - Winter Mid-Peak	10.05, 10.06	1.1106	$ 0.03235	$ 0.03361	$ 0.02751	$ 0.02906	$ 0.02792					$ 0.02425	$ 0.02663	$ 0.03205
15	Large General Service - TOD - Winter Off-Peak	10.05, 10.06	0.8499	$ 0.02476	$ 0.02572	$ 0.02105	$ 0.02224	$ 0.02136					$ 0.01856	$ 0.02038	$ 0.02452
16	Large General Service - TOD - Summer On-Peak	10.05, 10.06	1.2664						$ 0.02793	$ 0.02795	$ 0.02936	$ 0.02818			
17	Large General Service - TOD - Summer Mid-Peak	10.05, 10.06	0.9956						$ 0.02196	$ 0.02197	$ 0.02308	$ 0.02216			
18	Large General Service - TOD - Summer Off-Peak	10.05, 10.06	0.6896						$ 0.01521	$ 0.01522	$ 0.01599	$ 0.01535			
19	Irrigation Service	11.02	0.9250	$ 0.02695	$ 0.02800	$ 0.02291	$ 0.02420	$ 0.02325	$ 0.02040	$ 0.02041	$ 0.02144	$ 0.02059	$ 0.02020	$ 0.02218	$ 0.02669
20	Outdoor Lighting	11.03, 11.04, 11.07	0.8645	$ 0.02519	$ 0.02616	$ 0.02141	$ 0.02262	$ 0.02173	$ 0.01907	$ 0.01908	$ 0.02004	$ 0.01924	$ 0.01888	$ 0.02073	$ 0.02494
21	OPA	11.05	1.0210	$ 0.02974	$ 0.03090	$ 0.02529	$ 0.02672	$ 0.02566	$ 0.02252	$ 0.02253	$ 0.02367	$ 0.02272	$ 0.02229	$ 0.02448	$ 0.02946
22	Controlled Service Deferred Load	14.01, 14.06	0.9513	$ 0.02771	$ 0.02879	$ 0.02356	$ 0.02489	$ 0.02391	$ 0.02098	$ 0.02099	$ 0.02205	$ 0.02117	$ 0.02077	$ 0.02281	$ 0.02745
23	Controlled Service Interruptible	14.04	0.9883	$ 0.02879	$ 0.02991	$ 0.02448	$ 0.02586	$ 0.02484	$ 0.02180	$ 0.02181	$ 0.02291	$ 0.02199	$ 0.02158	$ 0.02370	$ 0.02852
24	Controlled Service Off-Peak	14.07, 14.12	0.9164	$ 0.02670	$ 0.02774	$ 0.02270	$ 0.02398	$ 0.02303	$ 0.02021	$ 0.02022	$ 0.02125	$ 0.02039	$ 0.02001	$ 0.02197	$ 0.02644

(1) As of the date of this filing, there is no Commission-approved true-up factor to be included in 2024 rates.
(2) Minnesota Class EAF Ratios in 13.01 Tariff as filed by Otter Tail on March 8, 2022, in Docket No. E017/GR-20-719.

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
AVERAGE COST OF ENERGY CALCULATION

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(M)
Line No.	**Description**	**Source Attachment**	**January-25**	**February-25**	**March-25**	**April-25**	**May-25**	**June-25**	**July-25**	**August-25**	**September-25**	**October-25**	**November-25**	**December-25**	**Year End Total**
1	Plant Generation	Attachment 3.1 (Line 89)	$ 7,937,031	$ 5,767,222	$ 4,945,425	$ 2,718,426	$ 2,677,236	$ 5,060,461	$ 8,352,823	$ 7,930,418	$ 5,207,405	$ 4,678,564	$ 5,685,885	$ 6,970,888	$ 67,931,785
2	Steam Plant Reagents	Attachment 3.1 (Line 125)	$ 342,259	$ 341,542	$ 278,164	$ 82,404	$ 106,224	$ 224,003	$ 331,233	$ 337,012	$ 237,230	$ 173,385	$ 300,288	$ 345,136	$ 3,098,880
3	Purchased Power	Attachment 3.1 (Line 99)	$ 11,795,627	$ 11,007,991	$ 8,430,639	$ 9,716,285	$ 8,696,267	$ 6,183,907	$ 4,168,752	$ 4,179,648	$ 6,277,254	$ 6,616,896	$ 7,782,501	$ 11,274,678	$ 96,130,445
4	Wind Curtailment	Attachment 5 (Line 8)	$ (2,273)	$ (1,739)	$ 19,907	$ 3,354	$ 19,240	$ 42,165	$ 10,958	$ (8,199)	$ 819	$ 25,136	$ 11,356	$ 6,995	$ 127,718
5	Intersystem Sales (Fuel Cost of Asset-Based Sales)	Attachment 3.1 (Line 103)	$ (749,893)	$ (30,982)	$ (36,986)	$ (25,936)	$ (20,823)	$ (468,814)	$ (783,337)	$ (557,404)	$ (397,426)	$ (161,884)	$ (72,412)	$ (272,883)	$ (3,578,779)
6	MISO Resource Book Charge (excluding Schedule 16 & 17)	Attachment 4.1 (Line 61)	$ (1,397,504)	$ (1,033,614)	$ (1,002,607)	$ (684,492)	$ (668,489)	$ (916,771)	$ (958,355)	$ (990,658)	$ (835,438)	$ (827,347)	$ (894,750)	$ (1,055,744)	$ (11,265,769)
7	SPP Resource Book Charge	Attachment 4.2 (Line 43)	$ (218,289)	$ (236,781)	$ (110,156)	$ (57,983)	$ (54,429)	$ (290,635)	$ (57,462)	$ (57,104)	$ (54,405)	$ (57,078)	$ (62,838)	$ (70,449)	$ (1,327,608)
8	MISO Ancillary Services Market	Attachment 4.3 (Line 33)	$ (83,106)	$ (5,455)	$ (29,868)	$ (44,363)	$ (63,896)	$ (80,545)	$ (108,381)	$ (11,307)	$ (101,317)	$ 9,654	$ (26,411)	$ 70,500	$ (474,493)
9	Hoot Lake Solar Generation Credit	Attachment 3.3 (Line 17)	$ (172,659)	$ (237,314)	$ (338,811)	$ (361,014)	$ (401,656)	$ (403,177)	$ (556,580)	$ (408,260)	$ (360,012)	$ (218,094)	$ (147,757)	$ (131,274)	$ (3,736,608)
10	Steam and Water Sales - Net Margin	Attachment 3.2 (Line 9)	$ (104,055)	$ (99,700)	$ (129,220)	$ (91,541)	$ (96,739)	$ (97,674)	$ (139,790)	$ (138,027)	$ (88,698)	$ (49,480)	$ (125,612)	$ (104,055)	$ (1,264,592)
11	Asset-Based Margins - 100%	Attachment 3.1 (Line 104)	$ (1,187,587)	$ (26,327)	$ (40,117)	$ (14,579)	$ (21,727)	$ (591,857)	$ (1,128,821)	$ (721,094)	$ (456,183)	$ (168,099)	$ (84,987)	$ (424,262)	$ (4,865,639)
12															
13	**Fuel Costs & Purchase Power for System Use**		$ 16,159,551	$ 15,444,844	$ 11,986,371	$ 11,240,560	$ 10,171,210	$ 8,661,062	$ 9,131,039	$ 9,555,026	$ 9,429,229	$ 10,021,653	$ 12,365,264	$ 16,609,529	$ 140,775,339
14															
15	**Energy for System Use (kWh)**	Attachment 6 (Line 38)	595,596,123	546,423,644	526,495,043	465,141,417	439,648,648	431,882,951	455,028,148	451,076,646	423,712,379	459,000,219	515,733,969	575,638,690	5,885,377,876
16															
17	**Cost per kWh**	**Line 13 / Line 15**	**$ 0.02713**	**$ 0.02827**	**$ 0.02277**	**$ 0.02417**	**$ 0.02314**	**$ 0.02005**	**$ 0.02007**	**$ 0.02118**	**$ 0.02225**	**$ 0.02183**	**$ 0.02398**	**$ 0.02885**	**$ 0.02392**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 SALES FORECAST KWH

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	**Description**	**January-25**	**February-25**	**March-25**	**April-25**	**May-25**	**June-25**	**July-25**	**August-25**	**September-25**	**October-25**	**November-25**	**December-25**	**TOTAL**
1	**Coal (tons)**	**[PROTECTED DATA BEGINS...**												
2	Big Stone													
3	Coyote													
4	**Total Coal**													1,227,940
5														
6	**Oil - Coal Units (Gallons)**													
7	Big Stone													
8	Coyote													
9	**Total Oil - Coal Units**													376,823
10														
11	**Oil - Peaking Units (Gallons)**													
12	Jamestown 1													
13	Jamestown 2													
14	Lake Preston													
15	**Total Oil - Peaking units**													92,017
16														
17	**Natural Gas (MMBTU)**													
18	Solway													
19	Astoria													
20	**Total Natural Gas**													6,396,052
21														
22														
23	**Energy (MWh)**													
24	Big Stone													
25	Coyote													
26	**Total Coal**													1,986,376
27														
28	**Wind & Solar**													
29	Langdon													
30	Ashtabula													
31	Ashtabula III													
32	Luverne													
33	Merricourt													
34	Hoot Lake Solar													
35	**Total Wind & Solar**													1,368,270
36														
37	**Hydro**													20,000
38														
39	**Peaking Units**													
40	Jamestown 1													
41	Jamestown 2													
42	Lake Preston													
43	**Total Peaking units**													874
44														
45	**Natural Gas**													
46	Solway													
47	Astoria													
48	**Total Natural Gas**													519,795
49														**...PROTECTED DATA ENDS]**
50	**OTP-Owned Total**	416,078	344,441	325,404	195,267	206,568	293,267	411,681	384,940	313,633	308,070	329,205	366,760	3,895,315
51														
52	**Purchases**	**[PROTECTED DATA BEGINS...**												
53	Edgeley PPA													
54	Langdon PPA													
55	Tribal (WAPA) excluded from Total													
56	Shared Load													
57	Small Co-gen													
58	Bilateral purchases													
59	Market Purchases													
60														**...PROTECTED DATA ENDS]**
61	**Total Purchases excluding Tribal (WAPA)**	219,536	220,262	218,727	291,384	250,914	175,617	99,876	114,461	158,290	176,444	199,357	230,592	2,355,460
62														
63	Less: Asset Based Sales	27,238	1,166	1,485	699	706	17,887	29,954	20,711	15,282	6,044	2,796	9,264	133,231
64														
65	**System Use**	**608,377**	**563,537**	**542,646**	**485,952**	**456,776**	**450,997**	**481,603**	**478,690**	**456,641**	**478,470**	**525,765**	**588,088**	**6,117,544**
66														

67														
68	**Fuel Costs - Coal**	**[PROTECTED DATA BEGINS...**												
69	Big Stone													
70	Coyote													
71	**Total Fuel Costs - Coal**													$ 50,427,138
72														
73	**Fuel Oil Costs - Coal Units**													
74	Big Stone													
75	Coyote													
76	**Total Fuel Oil Costs - Coal Units**													$ 926,688
77														
78	**Fuel Oil Costs - Peaking Units**													
79	Jamestown 1													
80	Jamestown 2													
81	Lake Preston													
82	**Total Fuel Oil Costs - Peaking Units**													$ 246,353
83														
84	**Fuel Costs - Natural Gas ($)**													
85	Solway													
86	Astoria													
87	**Total Fuel Costs - Natural Gas Units**													$ 16,331,606
88														
89	**Total OTP-Owned Fuel Costs**	$ 7,937,031	$ 5,767,222	$ 4,945,425	$ 2,718,426	$ 2,677,236	$ 5,060,461	$ 8,352,823	$ 7,930,418	$ 5,207,405	$ 4,678,564	$ 5,685,885	$ 6,970,888	$ 67,931,785
90														
91	**Purchases ($)**													
92	Edgeley PPA													
93	Langdon PPA													
94	Tribal (WAPA) excluded from Total*													
95	Shared Load													
96	Small Co-gen													
97	Bilateral Purchases													
98	Market Purchases													
														...PROTECTED DATA ENDS]
99	**Total Purchases excluding Tribal (WAPA)***	$ 11,795,627	$ 11,007,991	$ 8,430,639	$ 9,716,285	$ 8,696,267	$ 6,183,907	$ 4,168,752	$ 4,179,648	$ 6,277,254	$ 6,616,896	$ 7,782,501	$ 11,274,678	$ 96,130,445
100														
101	Asset Based Sales	$ (1,937,481)	$ (57,308)	$ (77,103)	$ (40,515)	$ (42,549)	$ (1,060,671)	$ (1,912,158)	$ (1,278,498)	$ (853,609)	$ (329,982)	$ (157,399)	$ (697,145)	$ (8,444,419)
102	Avg thermal Cost ($/MWh)	$ 28	$ 27	$ 25	$ 37	$ 29	$ 26	$ 26	$ 27	$ 26	$ 27	$ 26	$ 29	$ 25.51
103	Fuel Cost of Sales	$ 749,893	$ 30,982	$ 36,986	$ 25,936	$ 20,823	$ 468,814	$ 783,337	$ 557,404	$ 397,426	$ 161,884	$ 72,412	$ 272,883	$ 3,578,779
104	Margin	$ (1,187,587)	$ (26,327)	$ (40,117)	$ (14,579)	$ (21,727)	$ (591,857)	$ (1,128,821)	$ (721,094)	$ (456,183)	$ (168,099)	$ (84,987)	$ (424,262)	$ (4,865,639)
105														
106	**Fuel Cost + Purchased Power for System Use**	**$ 17,795,177**	**$ 16,717,904**	**$ 13,298,962**	**$ 12,394,195**	**$ 11,330,954**	**$ 10,183,697**	**$ 10,609,416**	**$ 10,831,568**	**$ 10,631,050**	**$ 10,965,478**	**$ 13,310,987**	**$ 17,548,421**	**$ 155,617,811**
107														
108														
109	**Reagents**	**[PROTECTED DATA BEGINS...**												
110	BSP Pebble Lime ($/MWH)													
111	BSP Pebble Lime ($)													
112														
113	BSP Act. Carbon ($/MWH)													
114	BSP Act. Carbon ($)													
115														
116	BSP Anh. Ammonia ($/MWH)													
117	BSP Anh. Ammonia ($)													
118														
119	COY Lime ($/MWH)													
120	COY Lime ($)													
121														
122	COY Act. Carbon ($/MWH)													
123	COY Act. Carbon ($)													
124														**...PROTECTED DATA ENDS]**
125	**Total Reagents**	**$ 342,259**	**$ 341,542**	**$ 278,164**	**$ 82,404**	**$ 106,224**	**$ 224,003**	**$ 331,233**	**$ 337,012**	**$ 237,230**	**$ 173,385**	**$ 300,288**	**$ 345,136**	**$ 3,098,880**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
		2025 Big Stone Plant Steam and Water Sales Forecast												
Line No.		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
		[PROTECTED DATA BEGINS...												
1	Coal Burned for Steam and Water Sales ($)													
2	Pebble Lime for Steam and Water Sales ($)													
3	Activated Carbon for Steam and Water Sales ($)													
4	Anhydrous Ammonia for Steam and Water Sales ($)													
5	Total Costs for Steam and Water Sales ($)													
6														
7	Revenue from Steam and Water Sales													
8														**...PROTECTED DATA ENDS]**
9	**Net Margin**	**$ (104,055)**	**$ (99,700)**	**$ (129,220)**	**$ (91,541)**	**$ (96,739)**	**$ (97,674)**	**$ (139,790)**	**$ (138,027)**	**$ (88,698)**	**$ (49,480)**	**$ (125,612)**	**$ (104,055)**	**$ (1,264,592)**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.			**January-25**	**February-25**	**March-25**	**April-25**	**May-25**	**June-25**	**July-25**	**August-25**	**September-25**	**October-25**	**November-25**	**December-25**	**Total**
		[PROTECTED DATA BEGINS...													
1	Forecasted Market purchases $/MWh														
2															
3	Forecasted Hoot Lake Solar MWh Output														
4															
5	Avoided Market Purchases due to Hoot Lake Solar Output (Total System)	Line 1 x Line 3													
6															
7															
8	Forecasted MN Sales Subject to COE - kWh														
9	Forecasted Total System sales - kWh														
10															
11	MN Sales as % of Total Sales	Line 8 / Line 9													
12															
13	Avoided cost captured by MN Customers in existing mechanism calculation (MN Share)	Line 5 x Line 11													
14															
15	Avoided cost not captured by MN Customers in existing mechanism calculation (MN Share)	Line 13 - Line 5													
16														**...PROTECTED DATA ENDS]**	
17	Amount credited to MN EAR Calculation (grossed up to system total) (Total System)	Line 15 / Line 11	**$ (172,659)**	**$ (237,314)**	**$ (338,811)**	**$ (361,014)**	**$ (401,656)**	**$ (403,177)**	**$ (556,580)**	**$ (408,260)**	**$ (360,012)**	**$ (218,094)**	**$ (147,757)**	**$ (131,274)**	**$ (3,736,608)**

Otter Tail Power Company
MISO Wholesale Market Charges (Non-Energy)
2025 FORECAST

Line No.	Charge Type Description	Acct	January	February	March	April	May	June	July	August	September	October	November	December	Total Annual Forecast
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
	Day Ahead & Real Time Asset & Non Asset Energy & Loss														
1	DA Asset Energy Amount***	555.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	DA Non-asset Energy Amount***	555.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	RT Asset Energy Amount***	555.19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	RT Distribution of Losses Amount	555.24	$ (388,069)	$ (359,452)	$ (346,303)	$ (310,271)	$ (291,757)	$ (288,048)	$ (307,544)	$ (305,690)	$ (291,632)	$ (305,547)	$ (335,550)	$ (375,189)	$ (3,905,053)
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	DA Loss Amount		$ 735,943	$ 681,673	$ 656,736	$ 588,405	$ 553,295	$ 546,261	$ 583,232	$ 579,718	$ 553,058	$ 579,445	$ 636,345	$ 711,516	$ 7,405,629
8	RT Loss Amount		$ 44,342	$ 41,072	$ 39,570	$ 35,453	$ 33,337	$ 32,913	$ 35,141	$ 34,929	$ 33,323	$ 34,913	$ 38,341	$ 42,870	$ 446,204
9	RT Non-Asset Energy Amount***	555.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	**TOTAL**		**$ 392,216**	**$ 363,293**	**$ 350,003**	**$ 313,587**	**$ 294,875**	**$ 291,126**	**$ 310,830**	**$ 308,957**	**$ 294,749**	**$ 308,812**	**$ 339,136**	**$ 379,198**	**$ 3,946,779**
	Virtual Energy														
12	DA Virtual Energy Amount	555.12	-	-	-	-	-	-	-	-	-	-	-	-	$ -
13	RT Virtual Energy Amount	555.32	-	-	-	-	-	-	-	-	-	-	-	-	$ -
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Schedules 16 & 17														
15	DA Mkt Admin Amount	555.01	$ 74,914	$ 87,588	$ 72,459	$ 64,615	$ 59,755	$ 63,208	$ 73,261	$ 68,398	$ 62,255	$ 70,854	$ 75,430	$ 77,384	$ 850,121
16	RT Mkt Admin Amount	555.18	$ 8,518	$ 12,001	$ 10,862	$ 10,089	$ 10,761	$ 10,390	$ 10,987	$ 9,812	$ 9,494	$ 11,853	$ 11,114	$ 11,136	$ 127,018
17	FTR Mkt Admin Amount	555.13	$ 1,312	$ 1,702	$ 1,349	$ 1,843	$ 2,017	$ 2,110	$ 2,180	$ 2,120	$ 1,926	$ 1,872	$ 1,691	$ 1,727	$ 21,848
18	**TOTAL**		**$ 84,745**	**$ 101,291**	**$ 84,671**	**$ 76,546**	**$ 72,533**	**$ 75,708**	**$ 86,428**	**$ 80,329**	**$ 73,676**	**$ 84,579**	**$ 88,235**	**$ 90,248**	**$ 998,987**
	Congest & FTRs														
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DA Congestion		$ 2,501,918	$ 2,317,421	$ 2,232,647	$ 2,000,347	$ 1,880,988	$ 1,857,073	$ 1,982,762	$ 1,970,813	$ 1,880,181	$ 1,969,888	$ 2,163,325	$ 2,418,877	$ 25,176,241
21	RT FBT Congestion Amount	555.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	RT Congestion		$ 293,472	$ 271,831	$ 261,887	$ 234,638	$ 220,638	$ 217,832	$ 232,576	$ 231,174	$ 220,543	$ 231,065	$ 253,755	$ 283,731	$ 2,953,142
23	FTR Hourly Allocation Amount	555.14	$ (3,781,124)	$ (3,502,296)	$ (3,374,177)	$ (3,023,105)	$ (2,842,718)	$ (2,806,576)	$ (2,996,528)	$ (2,978,470)	$ (2,841,500)	$ (2,977,072)	$ (3,269,411)	$ (3,655,624)	$ (38,048,602)
24	FTR Monthly Allocation Amount	555.15	$ (90,468)	$ (83,797)	$ (80,731)	$ (72,332)	$ (68,016)	$ (67,151)	$ (71,696)	$ (71,264)	$ (67,986)	$ (71,230)	$ (78,225)	$ (87,465)	$ (910,360)
25	FTR Yearly Allocation Amount	555.17	$ (312,193)	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (312,193)
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	FTR Full Funding Guarantee Amount	555.36	$ 217,668	$ (7,533)	$ (164,934)	$ (115,820)	$ (94,024)	$ 20,928	$ 15,263	$ (4,332)	$ (60,572)	$ (283,078)	$ (177,407)	$ (97,578)	$ (751,420)
28	FTR Guarantee Uplift Amount	555.37	$ (245,430)	$ (11,112)	$ 164,936	$ 113,975	$ 75,511	$ (24,985)	$ (24,637)	$ 4,332	$ 60,572	$ 290,732	$ 181,363	$ 83,118	$ 668,376
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ (5,551,558)	$ (5,551,558)	$ (5,028,146)	$ (3,922,956)	$ (3,922,956)	$ (5,238,471)	$ (5,238,471)	$ (5,238,471)	$ (5,857,971)	$ (5,857,971)	$ (5,857,971)	$ (5,551,558)	$ (62,818,060)
30	FTR Annual Transaction Amount	555.38	$ 5,401,650	$ 5,401,650	$ 4,869,311	$ 3,914,118	$ 3,914,118	$ 5,059,516	$ 5,059,516	$ 5,059,516	$ 5,757,546	$ 5,757,546	$ 5,757,546	$ 5,401,650	$ 61,353,684
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 8,627	$ 8,627	$ 21,712	$ 24,084	$ 24,084	$ 5,762	$ 5,762	$ 5,762	$ 13,833	$ 13,833	$ 13,837	$ 8,628	$ 154,551
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ (158,203)	$ (158,203)	$ (169,360)	$ (84,610)	$ (84,610)	$ (161,345)	$ (161,345)	$ (161,345)	$ (128,220)	$ (128,220)	$ (128,220)	$ (158,203)	$ (1,681,880)
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	**TOTAL**		**$ (1,715,641)**	**$ (1,314,970)**	**$ (1,266,857)**	**$ (931,660)**	**$ (896,985)**	**$ (1,137,416)**	**$ (1,196,798)**	**$ (1,182,284)**	**$ (1,023,573)**	**$ (1,054,506)**	**$ (1,141,408)**	**$ (1,354,424)**	**$ (14,216,522)**
	RSG & Make Whole Payments														
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.1	$ 15,706	$ 11,430	$ 13,575	$ 11,314	$ 17,005	$ 15,248	$ 13,037	$ 17,259	$ 13,613	$ 12,188	$ 15,039	$ 18,077	$ 173,493
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (2,949)	$ (5,836)	$ (2,162)	$ (15,944)	$ (9,871)	$ (10,631)	$ (45,697)	$ (29,039)	$ (3,284)	$ (8,270)	$ (4,882)	$ (138,566)
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 28,287	$ 339,449
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.3	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (195,680)	$ (2,348,157)
39	RT Price Volatility Make Whole Payment	555.42	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (54,103)	$ (649,241)
40	**TOTAL**		**$ (205,789)**	**$ (213,015)**	**$ (213,757)**	**$ (212,344)**	**$ (220,435)**	**$ (216,119)**	**$ (219,089)**	**$ (249,934)**	**$ (236,922)**	**$ (212,592)**	**$ (214,726)**	**$ (208,301)**	**$ (2,623,022)**
	Revenue Neutrality Uplift														
41	RT Revenue Neutrality Uplift Amount	555.28	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 128,456	$ 1,541,475
42	**TOTAL**		**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 128,456**	**$ 1,541,475**
	Other Charges														
43	RT Misc Amount	555.25	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (20,051)	$ (240,614)
44	RT Net Inadvertent Amount	555.27	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 112	$ 1,341
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	RT Demand Response Allocation Uplift Amount	555.59	$ 1,459	$ 2,641	$ 3,162	$ 18,011	$ 30,220	$ 21,152	$ 22,098	$ 5,129	$ 5,920	$ 2,772	$ 327	$ 858	$ 113,750
47	DA Ramp Product	555.63	$ (274)	$ (1,572)	$ (5,418)	$ (3,066)	$ (5,096)	$ (4,945)	$ (3,129)	$ (1,905)	$ (4,517)	$ (2,280)	$ (7,590)	$ (2,100)	$ (41,891)
48	RT Ramp Product	555.64	$ (28)	$ (547)	$ (296)	$ 426	$ (1,622)	$ (1,124)	$ (2,822)	$ (1,175)	$ (1,650)	$ (107)	$ (1,044)	$ (1,529)	$ (11,518)
49	RT Schedule 49 Cost Distribution Amount	555.65	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 22,038	$ 264,452
50	**TOTAL**		**$ 3,255**	**$ 2,621**	**$ (453)**	**$ 17,470**	**$ 25,600**	**$ 17,181**	**$ 18,245**	**$ 4,147**	**$ 1,852**	**$ 2,483**	**$ (6,208)**	**$ (673)**	**$ 85,519**
	ASM Charges														
51	RT ASM Non-Excessive Energy Amount***	555.55	-	-	-	-	-	-	-	-	-	-	-	-	$ -
52	RT ASM Excessive Energy Amount***	555.56	-	-	-	-	-	-	-	-	-	-	-	-	$ -
53	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	-	-	-	-	-	-	-	-	-	-	-	-	$ -
55	DA Losses Rebate on COGA	555.06	-	-	-	-	-	-	-	-	-	-	-	-	$ -
56	RT Congestion Rebate on COGA	555.22	-	-	-	-	-	-	-	-	-	-	-	-	$ -
57	RT Loss Rebate on COGA	555.23	-	-	-	-	-	-	-	-	-	-	-	-	$ -
58	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
59	**TOTAL MISO Day 2 Wholesale CHARGES**		$ (1,312,759)	$ (932,324)	$ (917,936)	$ (607,946)	$ (595,956)	$ (841,063)	$ (871,928)	$ (910,329)	$ (761,763)	$ (742,768)	$ (806,515)	$ (965,496)	$ (10,266,782)
60	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (84,745)	$ (101,291)	$ (84,671)	$ (76,546)	$ (72,533)	$ (75,708)	$ (86,428)	$ (80,329)	$ (73,676)	$ (84,579)	$ (88,235)	$ (90,248)	$ (998,987)
61	**Total Forecasted MISO Day 2 Wholesale Energy Market Charges**		**$ (1,397,504)**	**$ (1,033,614)**	**$ (1,002,607)**	**$ (684,492)**	**$ (668,489)**	**$ (916,771)**	**$ (958,355)**	**$ (990,658)**	**$ (835,438)**	**$ (827,347)**	**$ (894,750)**	**$ (1,055,744)**	**$ (11,265,769)**

*** These energy related charge types are forecasted in aggregate within Otter Tail's EnCompass forecast found on line 104, Market Purchases of Attachment 3.1

$ -

Otter Tail Power Company
SPP Wholesale Market Charges (Non-Energy)
2025 Forecast

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	**Charge Type Description**	**Acct**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total Forecast**
	Day Ahead & Real Time Asset & Non Asset Energy & Loss														
1	DA Asset Energy Amount***	555.19	-	-	-	-	-	-	-	-	-	-	-	-	$ -
2	DA Non-asset Energy Amount	555.03	-	-	-	-	-	-	-	-	-	-	-	-	$ -
3	RT Asset Energy Amount***	555.09	-	-	-	-	-	-	-	-	-	-	-	-	$ -
4	RT Non-Asset Energy Amount	555.00	-	-	-	-	-	-	-	-	-	-	-	-	$ -
5	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
6	**RSG & Make Whole Payments**														
7	DA Make-Whole-Payment Distribution Amount	555.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	RT Make-Whole-Payment Distribution Amount	555.10	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 1,092	$ 13,105
9	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**TOTAL**		**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 1,092**	**$ 13,105**
11	**Revenue Neutrality Uplift**														
12	RT Revenue Neutrality Uplift Distribution Amount	555.15	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 244	$ 2,925
13	**TOTAL**		**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 244**	**$ 2,925**
14	**Other Charges**														
15	DA Regulation-Down Distribution Amount	555.04	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 188
16	DA Regulation-Up Distribution Amount	555.05	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 703
17	DA Spinning Reserve Distribution Amount	555.06	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 860
18	DA Supplemental Reserve Distribution Amount	555.07	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 127
19	RT Contingency Reserve Deployment Failure Amount	555.08	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (22)
20	RT Over-Collected Losses Distribution Amount	555.11	$ (19,919)	$ (18,450)	$ (17,775)	$ (15,925)	$ (14,975)	$ (14,785)	$ (15,785)	$ (15,690)	$ (14,969)	$ (15,683)	$ (17,223)	$ (19,257)	$ (200,436)
21	RT Regulation-Down Distribution Amount	555.12	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 34
22	RT Regulation Non-Performance Distribution Amount	555.13	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (25)
23	RT Regulation-Up Distribution Amount	555.14	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (40)
24	RT Spinning Reserve Distribution Amount	555.16	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)
25	RT Supplemental Reserve Distribution Amount	555.17	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (38)
26	RT Pseudo Tie Congestion Amount	555.20	$ (39,627)	$ (36,705)	$ (35,362)	$ (31,683)	$ (29,793)	$ (29,414)	$ (31,405)	$ (31,215)	$ (29,780)	$ (31,201)	$ (34,264)	$ (38,312)	$ (398,761)
27	RT Pseudo Tie Loss Amount	555.21	$ (14,971)	$ (13,867)	$ (13,360)	$ (11,970)	$ (11,255)	$ (11,112)	$ (11,864)	$ (11,793)	$ (11,251)	$ (11,787)	$ (12,945)	$ (14,474)	$ (150,648)
28	Miscellaneous Amount	555.23	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 113
29	ARR Closeout Yearly Amount	555.26	$ -	$ -	$ -	$ -	$ -	$ (236,793)	$ (2)	$ -	$ -	$ -	$ -	$ -	$ (236,796)
30	RT Demand Reduction Distribution Amount	555.28	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1
31	RT Schedule 1A3 Amount	555.29	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 87
32	RT Schedule 1A4 Amount	555.30	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 425
33	DA Ramp-Up Distribution Amount	555.31	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 426
34	RT Ramp Capability Non-Performance Distribution Amount	555.33	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (7)
35	RT Ramp Capability Up Distribution Amount	555.34	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (32)
36	ARR Daily Amount - New Charge Type in 2024	555.36	$ (145,367)	$ (169,354)	$ (45,254)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (359,974)
37	**TOTAL**		**$ (219,651)**	**$ (238,143)**	**$ (111,518)**	**$ (59,345)**	**$ (55,790)**	**$ (291,872)**	**$ (58,824)**	**$ (58,466)**	**$ (55,766)**	**$ (58,438)**	**$ (64,199)**	**$ (71,811)**	**$ (1,343,824)**
38	**Grandfathered Charge Types**														
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 313
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	$ (0)	$ (0)	$ -	$ -	$ (0)	$ (0)	$ -	$ -	$ (0)	$ (1)	$ 0	$ (0)	$ (2)
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	$ -	$ -	$ -	$ -	$ -	$ (125)	$ -	$ -	$ 0	$ -	$ -	$ -	$ (125)
42	**TOTAL**		**$ 26**	**$ 26**	**$ 26**	**$ 26**	**$ 26**	**$ (99)**	**$ 26**	**$ 26**	**$ 26**	**$ 25**	**$ 26**	**$ 26**	**$ 185**
43	**TOTAL FORECASTED SPP ENERGY MARKET CHARGES**		**$ (218,289)**	**$ (236,781)**	**$ (110,156)**	**$ (57,983)**	**$ (54,429)**	**$ (290,635)**	**$ (57,462)**	**$ (57,104)**	**$ (54,405)**	**$ (57,078)**	**$ (62,838)**	**$ (70,449)**	**$ (1,327,608)**
44															

*** These energy related charge types are forecasted in aggregate within Otter Tail's EnCompass forecast found on line 104, Market Purchases of Attachment 3.1

$ -

Otter Tail Power Company
MISO ASM Market Charges
2025 Forecast

Line No.	(A)	(B) January	(C) February	(D) March	(E) April	(F) May	(G) June	(H) July	(I) August	(J) September	(K) October	(L) November	(M) December	(N) 12-Month Total
1	Day Ahead Regulation Amount	$ (16,203)	$ (23,100)	$ (38,995)	$ (35,261)	$ (60,234)	$ (45,116)	$ (49,749)	$ (32,345)	$ (46,882)	$ (18,554)	$ (31,121)	$ (26,108)	$ (423,667)
2	Real Time Regulation Amount	$ (13,267)	$ (13,522)	$ (8,167)	$ (2,378)	$ (2,524)	$ (2,959)	$ (5,331)	$ (18,024)	$ (6,808)	$ (8,232)	$ (6,275)	$ (33,803)	$ (121,290)
3	Regulation Cost Distribution Amount	$ 17,466	$ 18,806	$ 20,142	$ 21,501	$ 28,465	$ 18,966	$ 15,315	$ 16,597	$ 16,030	$ 21,778	$ 24,915	$ 25,893	$ 245,873
4														
5	**Regulation Subtotal**	**$ (12,004)**	**$ (17,816)**	**$ (27,020)**	**$ (16,138)**	**$ (34,293)**	**$ (29,110)**	**$ (39,764)**	**$ (33,772)**	**$ (37,660)**	**$ (5,008)**	**$ (12,481)**	**$ (34,018)**	**$ (299,085)**
6														
7	Day Ahead Short-Term Reserve Amount	$ (122,191)	$ (3,406)	$ (7,216)	$ (24,956)	$ (24,834)	$ (31,541)	$ (14,747)	$ (47,614)	$ (32,969)	$ (7,302)	$ (19,227)	$ (14,550)	$ (350,553)
8	Real Time Short-Term Reserve Amount	$ 649	$ (413)	$ 1	$ 1,453	$ (58)	$ (244)	$ (4,302)	$ 794	$ (2,523)	$ (53)	$ (84)	$ (40,857)	$ (45,636)
9	Real Time Short-Term Reserve Cost Distribution Amount	$ 42,671	$ 3,002	$ 3,635	$ 12,102	$ 17,390	$ 12,047	$ 10,423	$ 33,142	$ 22,891	$ 13,522	$ 11,938	$ 56,449	$ 239,214
10														
11	**Short-Term Reserve Subtotal**	**$ (78,871)**	**$ (817)**	**$ (3,580)**	**$ (11,401)**	**$ (7,502)**	**$ (19,737)**	**$ (8,627)**	**$ (13,678)**	**$ (12,600)**	**$ 6,167**	**$ (7,373)**	**$ 1,043**	**$ (156,975)**
12														
13	Day Ahead Spinning Reserve Amount	$ (2,321)	$ (8,272)	$ (21,898)	$ (49,831)	$ (55,514)	$ (31,851)	$ (27,015)	$ (16,293)	$ (22,593)	$ (15,139)	$ (39,437)	$ (15,464)	$ (305,630)
14	Real Time Spinning Reserve Amount	$ (3,487)	$ (262)	$ (1,292)	$ 6,093	$ 1,473	$ (3,977)	$ (11,968)	$ 11,411	$ (11,202)	$ (2,034)	$ (374)	$ (57,869)	$ (73,489)
15	Spinning Reserve Cost Distribution Amount	$ 16,341	$ 12,678	$ 14,752	$ 22,137	$ 26,450	$ 17,843	$ 10,586	$ 13,970	$ 10,158	$ 21,926	$ 28,889	$ 26,496	$ 222,228
16														
17	**Spinning Reserve Subtotal**	**$ 10,533**	**$ 4,143**	**$ (8,438)**	**$ (21,602)**	**$ (27,590)**	**$ (17,985)**	**$ (28,398)**	**$ 9,087**	**$ (23,637)**	**$ 4,753**	**$ (10,921)**	**$ (46,838)**	**$ (156,891)**
18														
19														
20	Day Ahead Supplemental Reserve Amount	$ (18,339)	$ (3,401)	$ (2,990)	$ (9,979)	$ (18,688)	$ (31,054)	$ (42,416)	$ (28,624)	$ (13,511)	$ (10,789)	$ (7,222)	$ (13,335)	$ (200,347)
21	Real Time Supplemental Reserve Amount	$ 4,230	$ 1,549	$ 1,786	$ 3,909	$ 13,080	$ 5,046	$ (5,410)	$ 43,012	$ (25,956)	$ 2,386	$ 1,106	$ 154,275	$ 199,013
22	Supplemental Reserve Cost Distribution Amount	$ 2,595	$ 2,136	$ 1,624	$ 2,098	$ 2,346	$ 3,543	$ 7,483	$ 3,917	$ 3,296	$ 3,395	$ 1,729	$ 623	$ 34,786
23														
24	**Supplemental Reserve Subtotal**	**$ (11,515)**	**$ 284**	**$ 420**	**$ (3,972)**	**$ (3,262)**	**$ (22,465)**	**$ (40,343)**	**$ 18,306**	**$ (36,171)**	**$ (5,008)**	**$ (4,387)**	**$ 141,563**	**$ 33,451**
25														
26														
27	Contingency Reserve Deployment Failure Charge Amount	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 3,383	$ 40,593
28	Real Time Excessive Deficient Energy Deployment Charge Amount	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 3,929	$ 47,147
29	Net Regulation Adjustment Amount	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 1,439	$ 17,267
30														
31	**Other Charge Subtotal**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 8,751**	**$ 105,007**
32														
33	**TOTAL**	**$ (83,106)**	**$ (5,455)**	**$ (29,868)**	**$ (44,363)**	**$ (63,896)**	**$ (80,545)**	**$ (108,381)**	**$ (11,307)**	**$ (101,317)**	**$ 9,654**	**$ (26,411)**	**$ 70,500**	**$ (474,493)**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
1	2020 MWh							2	285	21	692	189	(283)	907
2	2021 MWh	16	31	(19)	587	(509)	383	59	(51)	(21)	348	686	(112)	1,397
3	2022 MWh	(137)	(7)	5	392	263	2,420	1,600	(1,143)	(47)	1,479	(253)	1,013	5,585
4	2023 MWh	(402)	(117)	1,537	(722)	1,718	423	(543)	72	130	45	536	95	2,772
5	2024 MWh	291	(85)											206
6	2025 MWh	(58)	(44)	508	86	491	1,075	279	(209)	21	641	290	178	3,256
7														
8	**Dollars (1)**	**$ (2,273)**	**$ (1,739)**	**$ 19,907**	**$ 3,354**	**$ 19,240**	**$ 42,165**	**$ 10,958**	**$ (8,199)**	**$ 819**	**$ 25,136**	**$ 11,356**	**$ 6,995**	**$ 127,718**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 SALES FORECAST KWH

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	Year End Total
1	**Minnesota**													
2	Residential	66,412,130	58,636,007	50,704,372	39,134,071	33,169,429	34,257,830	39,597,656	37,081,430	31,895,961	35,446,877	44,486,504	58,720,276	529,542,543
3	Farm	4,792,014	4,364,125	3,960,749	3,349,196	3,194,679	3,449,667	4,471,278	4,717,775	3,988,318	3,855,632	5,342,419	5,118,573	50,604,425
4	Small Commercial	37,162,716	33,531,676	31,371,774	25,531,497	23,066,387	23,120,619	25,844,941	25,541,276	23,791,955	26,660,600	31,530,575	36,308,441	343,462,457
5	Large Commercial	161,755,343	151,736,780	152,903,486	142,109,986	140,943,382	137,665,512	139,249,834	137,362,053	132,208,704	143,724,931	157,294,172	167,424,498	1,764,378,684
6	OPA	1,821,253	1,700,263	1,755,219	1,693,021	1,735,384	1,674,666	1,724,219	1,709,228	1,610,565	1,652,121	1,638,394	1,754,648	20,468,981
7	Streetlighting	437,602	392,438	380,717	379,544	362,844	387,457	363,540	364,603	389,704	383,213	423,675	414,662	4,679,999
8	**Total - Minnesota kWh**	272,381,058	250,361,289	241,076,317	212,197,315	202,472,105	200,555,751	211,251,468	206,776,365	193,885,207	211,723,374	240,715,739	269,741,098	2,713,137,089
9														
10	**North Dakota**													
11	Residential	77,866,240	68,688,378	60,552,107	45,879,006	37,005,506	34,787,587	40,199,455	37,985,208	32,818,150	39,168,550	50,849,719	68,103,299	593,903,205
12	Farm	4,447,973	3,573,558	3,383,770	2,800,557	2,592,613	2,050,147	2,030,088	2,250,964	2,962,453	3,580,379	5,433,224	5,636,016	40,741,742
13	Small Commercial	57,560,676	51,649,899	47,418,568	36,754,278	30,308,435	26,294,736	28,740,265	28,943,003	28,830,522	35,139,806	44,811,950	54,489,707	470,941,845
14	Large Commercial	127,352,946	119,918,523	124,411,851	123,202,204	125,010,608	125,175,139	127,708,468	129,518,885	122,215,477	126,428,475	126,290,535	126,285,200	1,503,518,311
15	OPA	1,677,603	1,577,584	1,581,461	1,517,145	1,474,473	1,565,125	1,721,573	1,684,856	1,466,840	1,377,174	1,390,840	1,594,356	18,629,030
16	Streetlighting	657,618	575,379	557,446	549,081	501,850	522,421	502,519	479,288	521,840	503,679	520,067	493,485	6,384,673
17	**Total - North Dakota kWh**	269,563,056	245,983,321	237,905,203	210,702,271	196,893,485	190,395,155	200,902,368	200,862,204	188,815,282	206,198,063	229,296,335	256,602,063	2,634,118,806
18														
19	**South Dakota**													
20	Residential	14,844,272	13,312,132	11,673,278	9,205,611	7,825,424	7,730,549	8,811,816	8,525,330	7,394,647	7,907,578	9,911,099	12,784,371	119,926,107
21	Farm	1,113,114	1,007,664	891,979	709,559	612,036	586,269	652,428	706,681	612,135	640,773	1,072,142	1,123,325	9,728,105
22	Small Commercial	8,899,094	7,990,378	7,504,524	5,985,958	5,378,777	5,199,097	5,913,255	5,828,421	5,419,522	5,849,298	7,405,133	8,577,685	79,951,142
23	Large Commercial	27,864,219	26,922,485	26,615,572	25,654,839	25,862,772	26,814,168	26,897,626	27,771,746	26,973,040	25,992,369	26,556,343	25,985,287	319,910,466
24	OPA	408,134	372,743	387,438	363,488	355,224	343,423	351,355	354,797	325,950	329,418	336,874	377,903	4,306,747
25	Streetlighting	125,349	113,452	112,021	113,531	103,450	110,709	105,165	101,562	110,340	102,550	107,555	99,219	1,304,903
26	**Total - South Dakota kWh**	53,254,182	49,718,854	47,184,812	42,032,986	40,137,683	40,784,215	42,731,645	43,288,537	40,835,634	40,821,986	45,389,146	48,947,790	535,127,470
27														
28	**Total -System Retail Sales**	595,198,296	546,063,464	526,166,332	464,932,572	439,503,273	431,735,121	454,885,481	450,927,106	423,536,123	458,743,423	515,401,220	575,290,951	5,882,383,365
29														
30	**Municipals**	**[PROTECTED DATA BEGINS...**												
31	Badger, SD													
32	Newfolden, MN													
33	Nielsville, MN													
34	Shelly, MN													
35														**...PROTECTED DATA ENDS]**
36	**Total - Municipals kWh**	397,827	360,180	328,711	208,845	145,374	147,829	142,667	149,539	176,255	256,796	332,749	347,739	2,994,511
37														
38	**Energy for System Use (kWh)**	595,596,123	546,423,644	526,495,043	465,141,417	439,648,648	431,882,951	455,028,148	451,076,646	423,712,379	459,000,219	515,733,969	575,638,690	5,885,377,876

Sales Forecast Description

Otter Tail Power Company (Otter Tail) developed its 2025 calendar year sales forecast in February 2024. The 2025 sales forecast statistical models use actual sales data through December 2023.

Otter Tail's sales estimate was developed by creating sales forecasts for the following classes:

- Residential
- Farm
- Small Commercial
- Large Commercial/Pipelines (MN and ND)[1]
- Other Public Authority (OPA)
- Streetlighting
- Unclassified[2]

To develop the 2025 Sales Forecast, Otter Tail used the forecasting software MetrixND (developed by Itron - https://www.itron.com/na/pages/default.aspx). Economic models were developed by state and by class. For most classes, Otter Tail used MetrixND to forecast the Use-Per-Meter (UPM) and forecast the Number of Meters for each state/class/month using historical sales, meter counts, economic data and weather data. For all classes, except Streetlighting, 20 years of historical data was used. With projects underway or recently completed to replace street lights to LED, shorter timeframes were used to develop those forecasts. The total sales forecast for each class was calculated by multiplying the forecasted UPM by the forecasted number of meters. These sales class models were summed at the state level to yield a state sales forecast, then all state forecasts were summed to produce a sales forecast at the system level.

Otter Tail does not model the pipeline customer's forecast. Pipeline pumping load is very significant, and it is best forecasted with direct input from the customers themselves. This load is also significantly impacted by world and national economic trends as well as federal and state energy and environmental policy. Otter Tail employs individuals that specialize in working with large commercial customers. They work very

[1] Sales for the Large Commercial and Pipeline classes have been combined to protect individual customer usage information.
[2] Unclassified sales include company use and are not applicable to the Energy Adjustment Rider calculation. Otter Tail must forecast Unclassified sales to determine its overall load but forecasted kWh sales for the Unclassified class are not included in the Energy Adjustment Rider calculation.

closely with the pipeline companies to acquire updated projections on demand (kW) and energy (kWh). For the purposes of this sales forecast, pipeline sales were developed based on the projections from the pipeline companies and with input from Otter Tail's specialists.

In addition to the pipelines, a number of Large Commerical customers are known to be starting service or making modifications to their existing service. These additions or modifications are also being accounted for in this forecast.

Class Forecasts

As noted earlier, Otter Tail developed its sales forecast at a class level for each state. Below is a discussion of each of the classes forecasted. In each of the bar graphs below, the solid bars represent weather normalized actual sales and the lined bars represent the 2025 weather normalized forecasted sales.

Minnesota

a) Residential

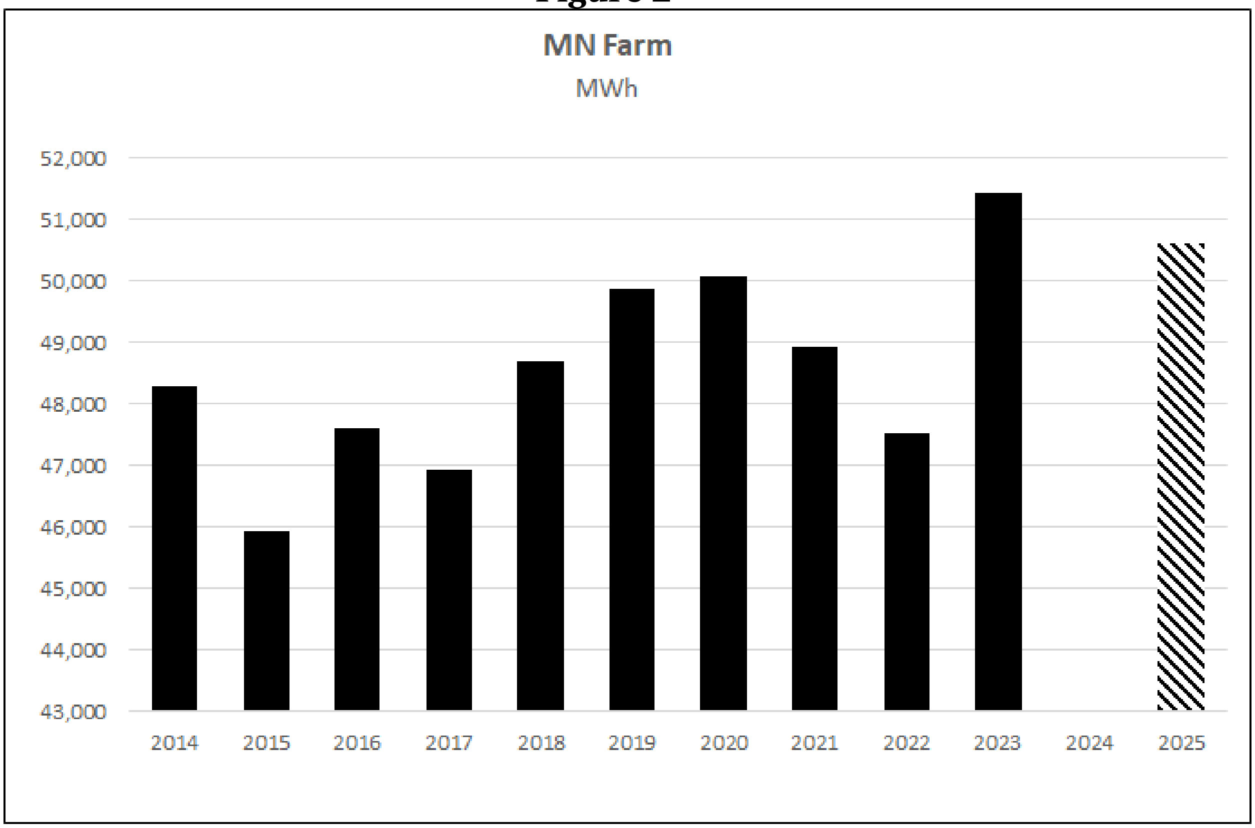
For the Minnesota Residential class, Otter Tail used weather and the Number of Households to forecast 2025 kWh sales. This class is extremely weather-sensitive, so weather is an important predictor of sales. Figure 1 shows the historic weather normalized sales and 2025 forecasted sales for the Minnesota Residential Class.

Figure 1

b) Farms

A historical sales trend was used as a predictor of farm UPM. Farm Employment was used as a predictor of farm meter counts. Weather also plays a part in predicting sales for this class. See Figure 2 for the historic weather normalized sales and 2025 forecasted sales for the Minnesota Farm Class.

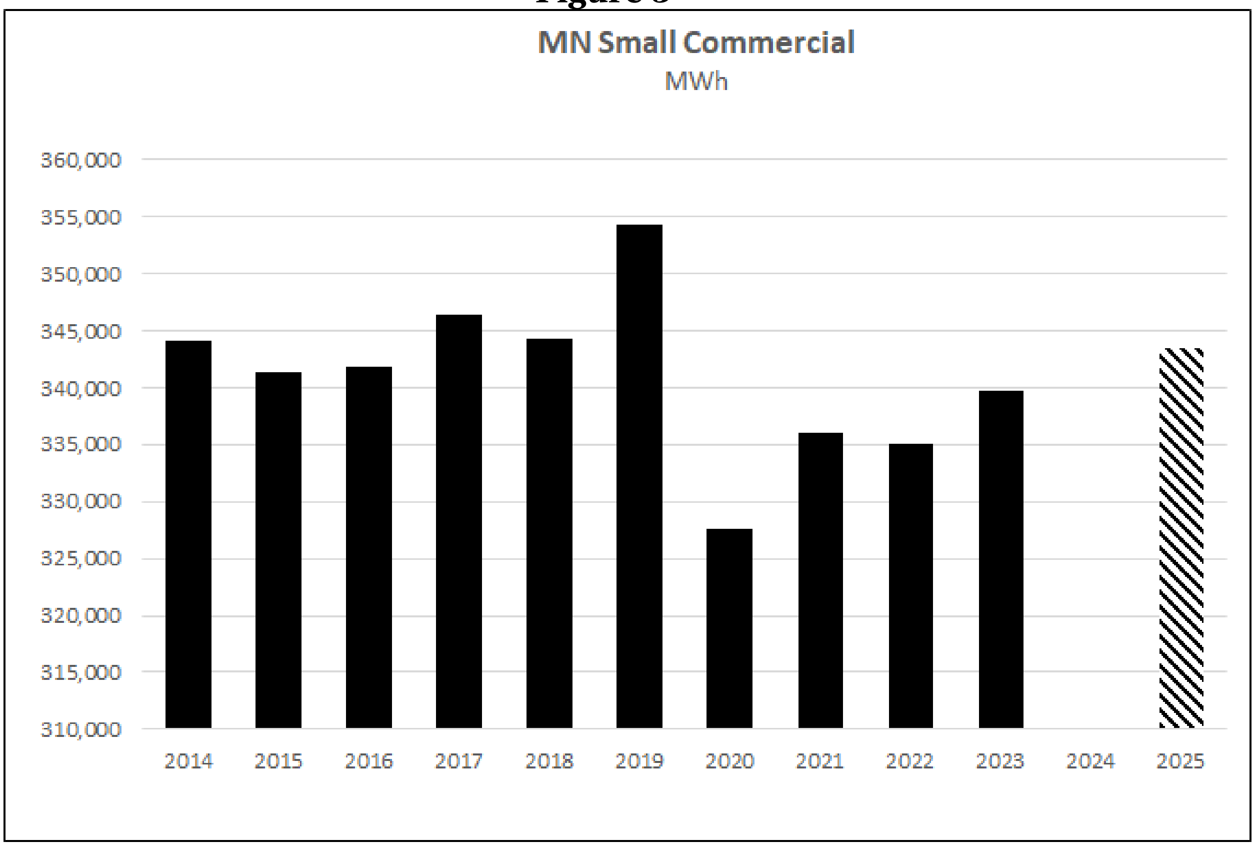
Figure 2



c) Small Commercial

The primary forecasting variables used for the Small Commercial class were weather and a Net Earnings economic variable. This class saw a large decrease in sales in 2020, most likely due to COVID; however, sales has continued to rebound from the 2020 level. Figure 3 shows the historic weather normalized sales and 2025 forecasted sales for the Small Commercial class.

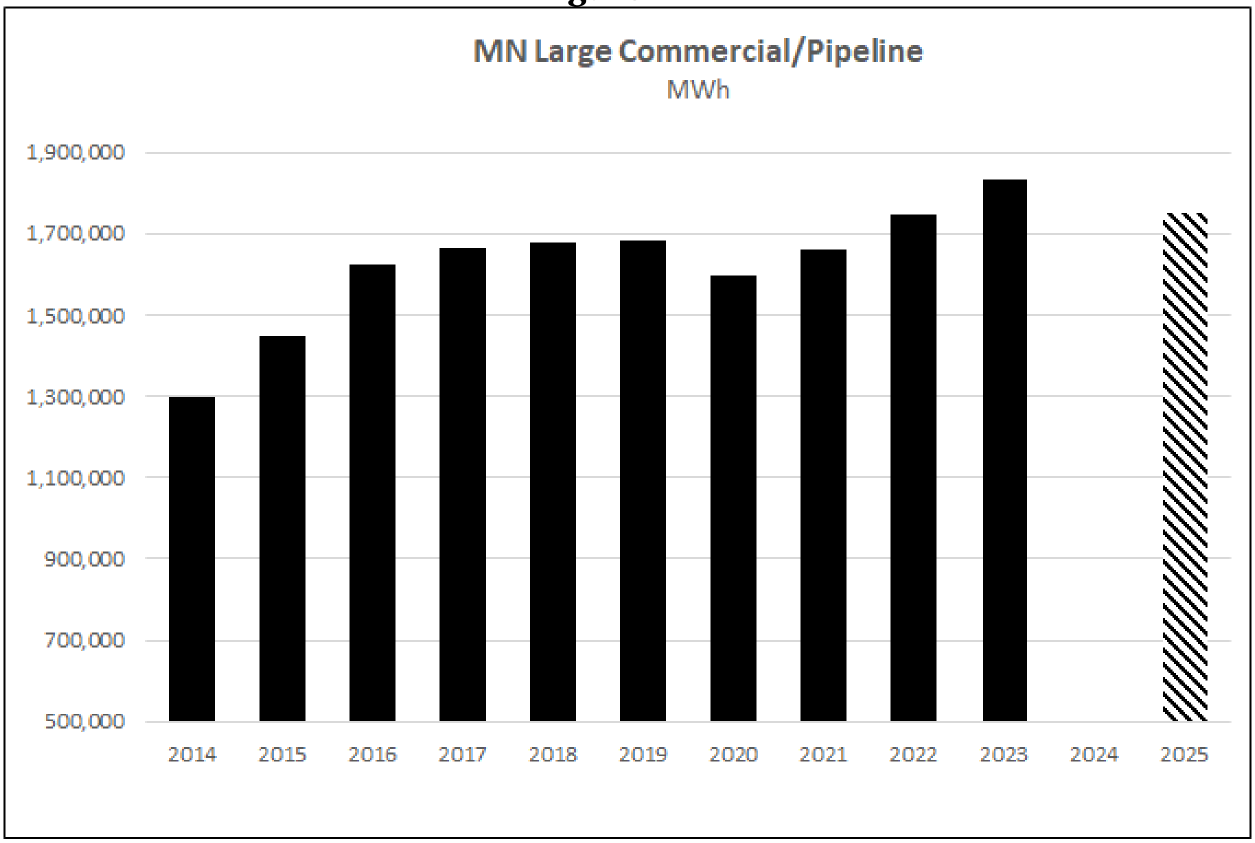
Figure 3



d) MN Large Commercial/Pipeline

Gross Regional Product was a key variable in the Large Commercial forecast. Pipelines are forecasted separately from the other Large Commercial customers, as described above. Figure 4 details the historic weather normalized sales and 2025 forecasted sales for the combined Large Commercial and Pipeline classes.

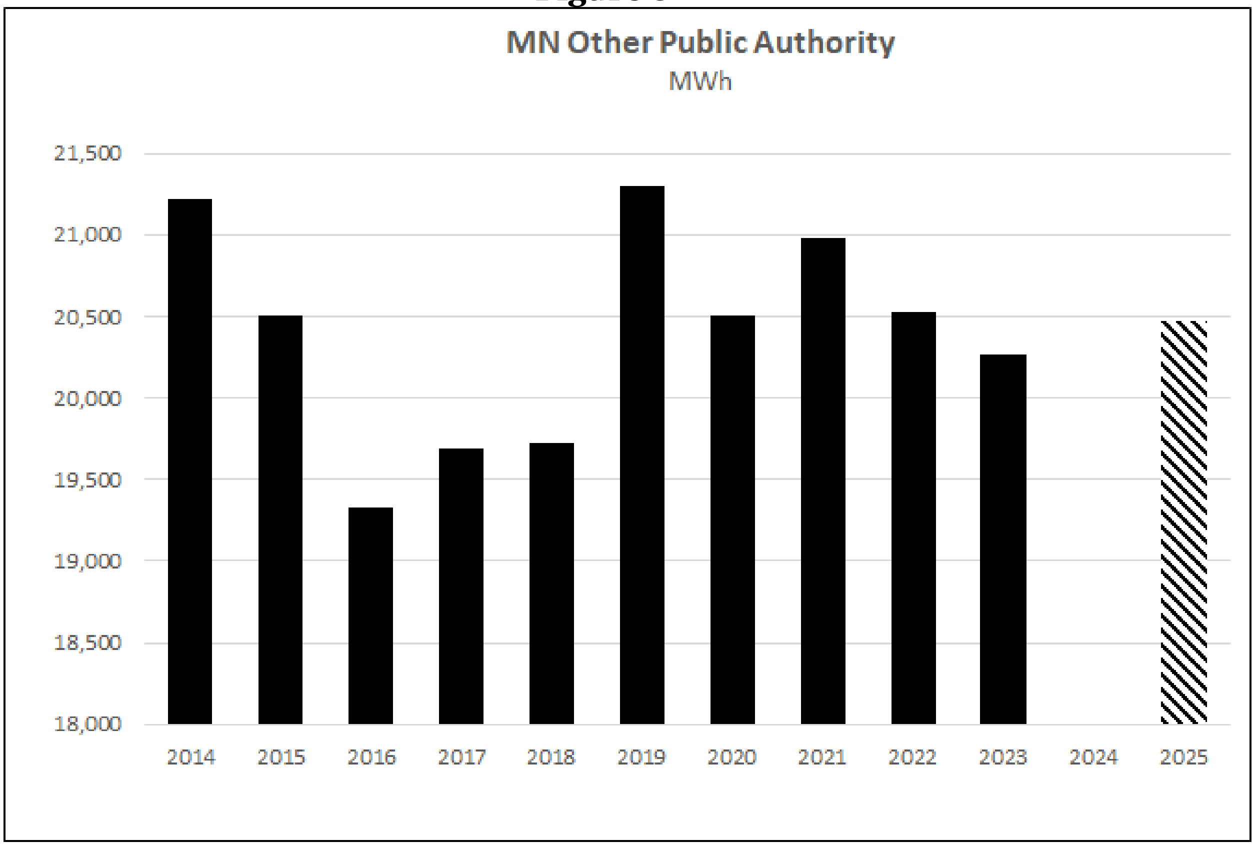
Figure 4



e) Other Public Authority (OPA)

Weather and a historical sales trend variable were the significant forecasting variables used for this class. Refer to Figure 5 below for historic weather normalized sales and 2025 forecasted sales for the OPA Class.

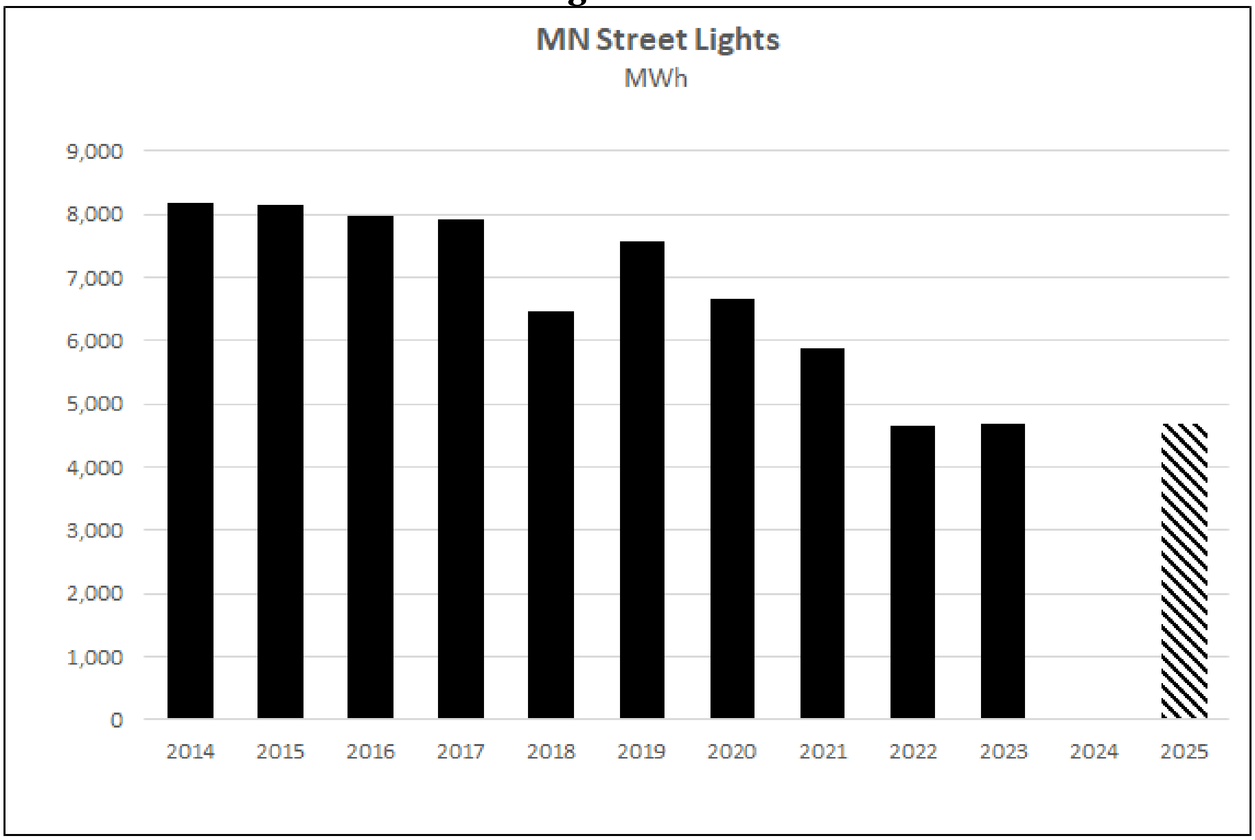
Figure 5



f) Street Lighting

Otter Tail's Street Lighting forecast shows a downward trend due to the deployment of more efficient LED bulbs. Figure 6 details the historic sales and 2025 forecasted sales for this class.

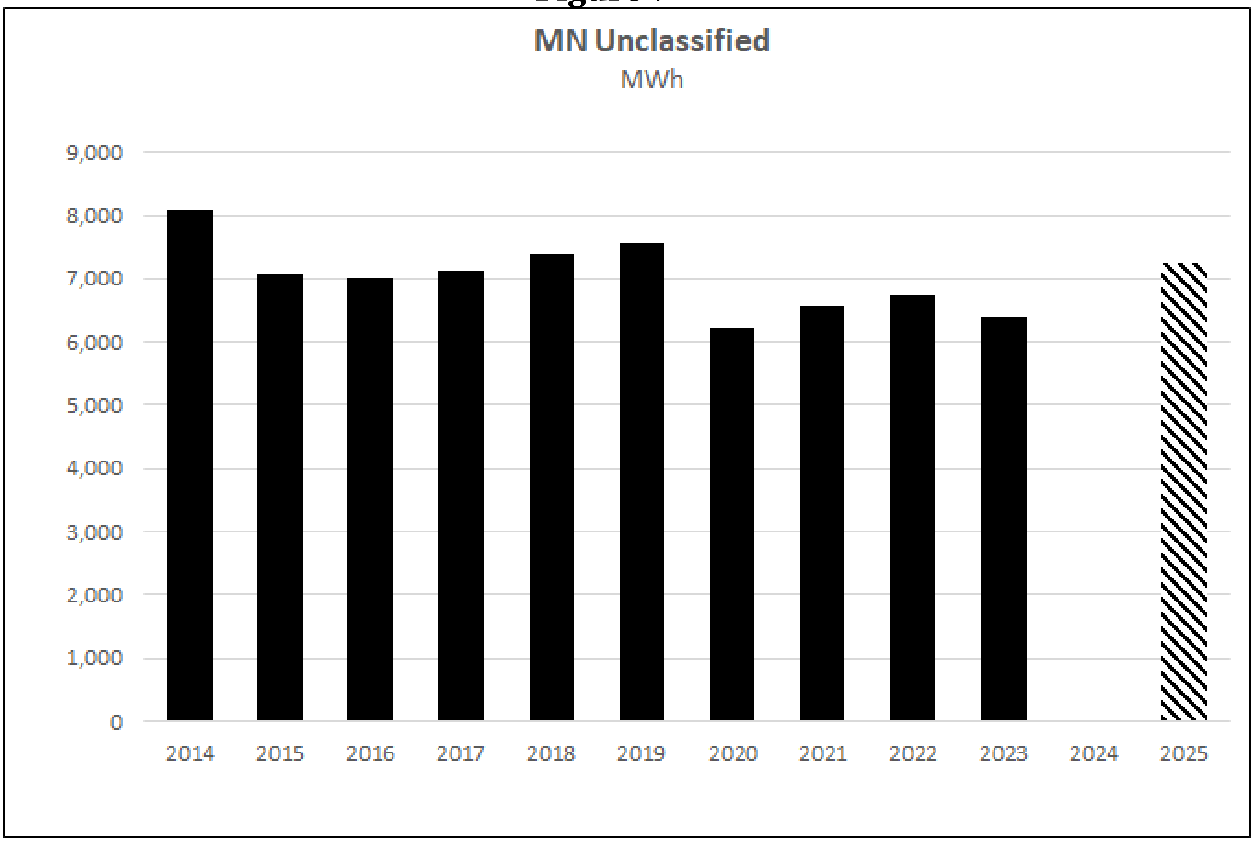
Figure 6



g) Unclassified

This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up less than 0.3 percent of Otter Tail's total kWh sales. See Figure 7 for the historic weather normalized sales and 2025 forecasted sales for this class.

Figure 7

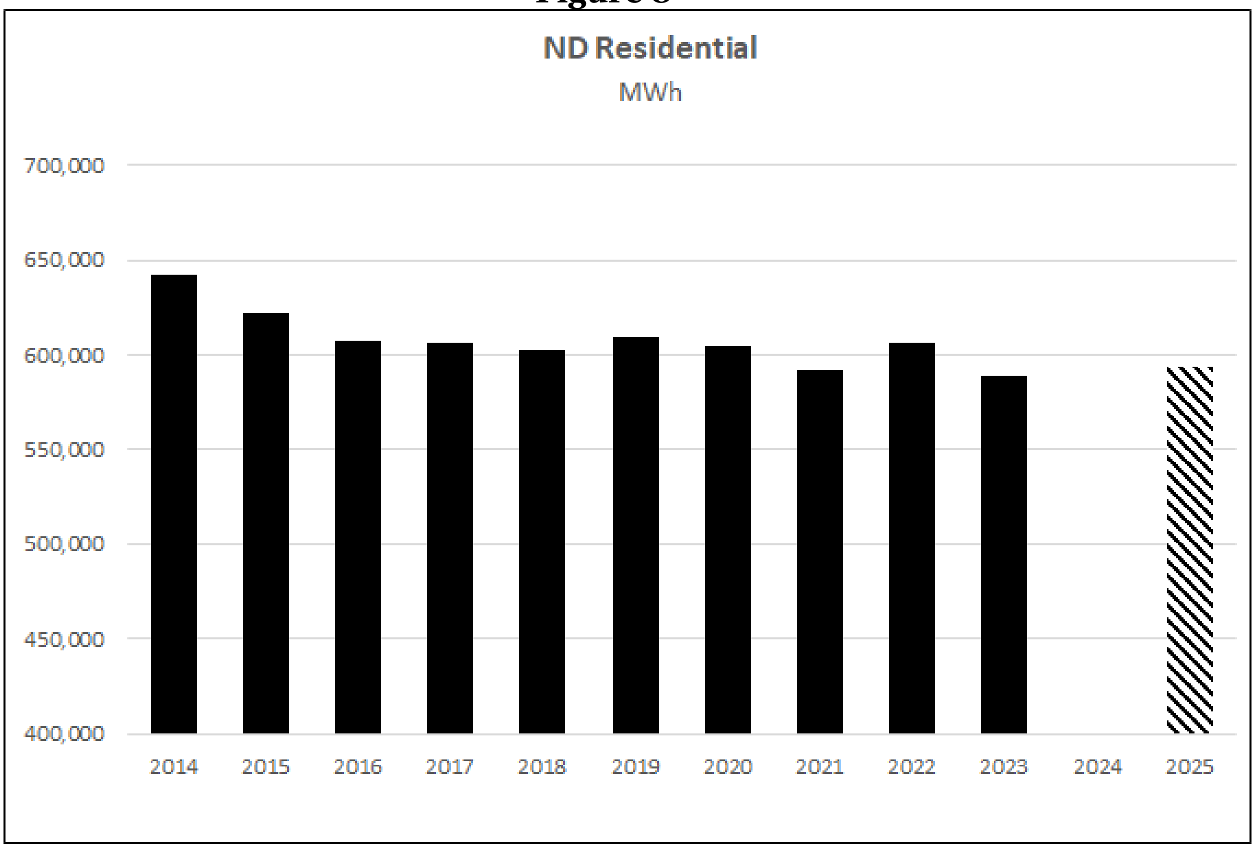


North Dakota

a) Residential

For the North Dakota Residential class, Otter Tail used weather and the Number of Households economic variable to forecast 2025 kWh. This class is extremely weather-sensitive, so weather is an important predictor of sales. Sales within this class have mostly been declining since 2014. Figure 8 shows the historic weather normalized sales and 2025 forecasted sales for the North Dakota Residential class.

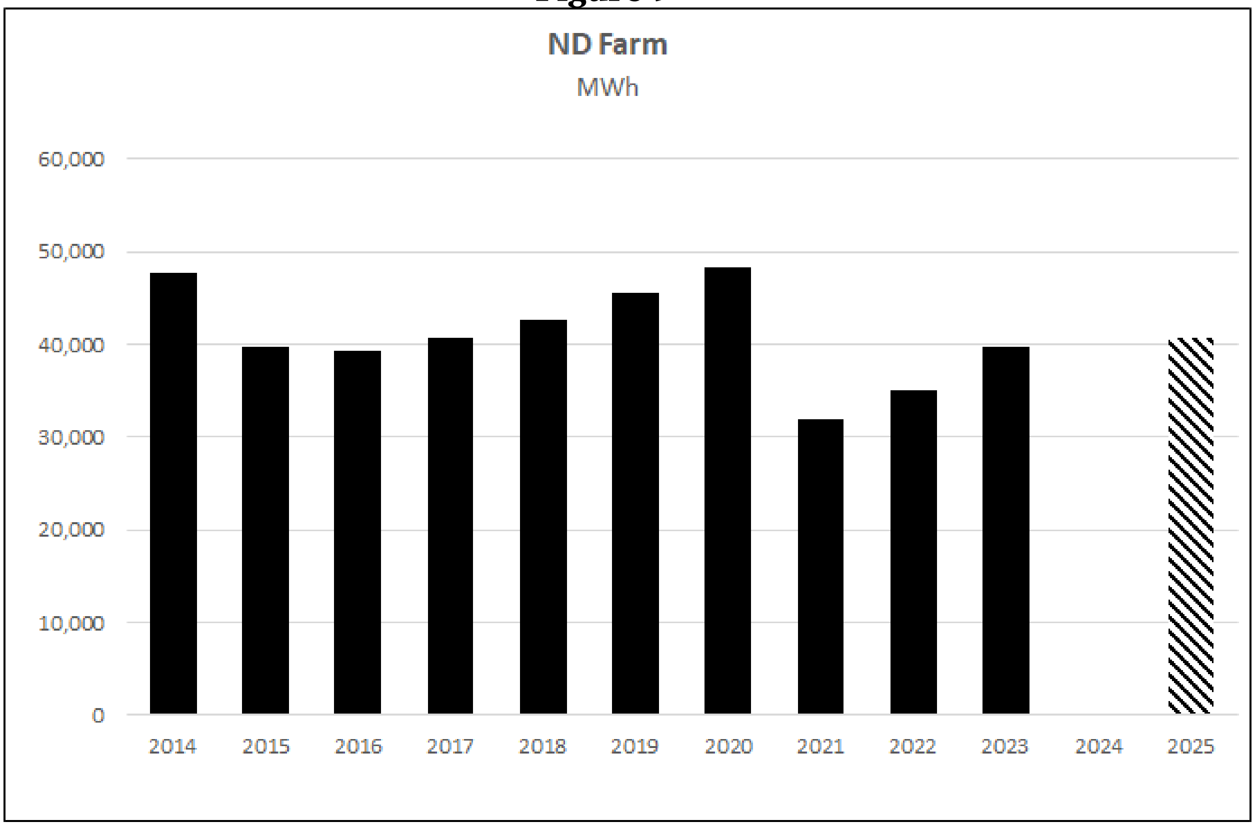
Figure 8



b) Farms

In the North Dakota Farm class, weather and a Farm Employment economic variable were selected to predict sales for this class. See Figure 9 for the historic weather normalized sales and 2025 forecasted sales for the Farm class.

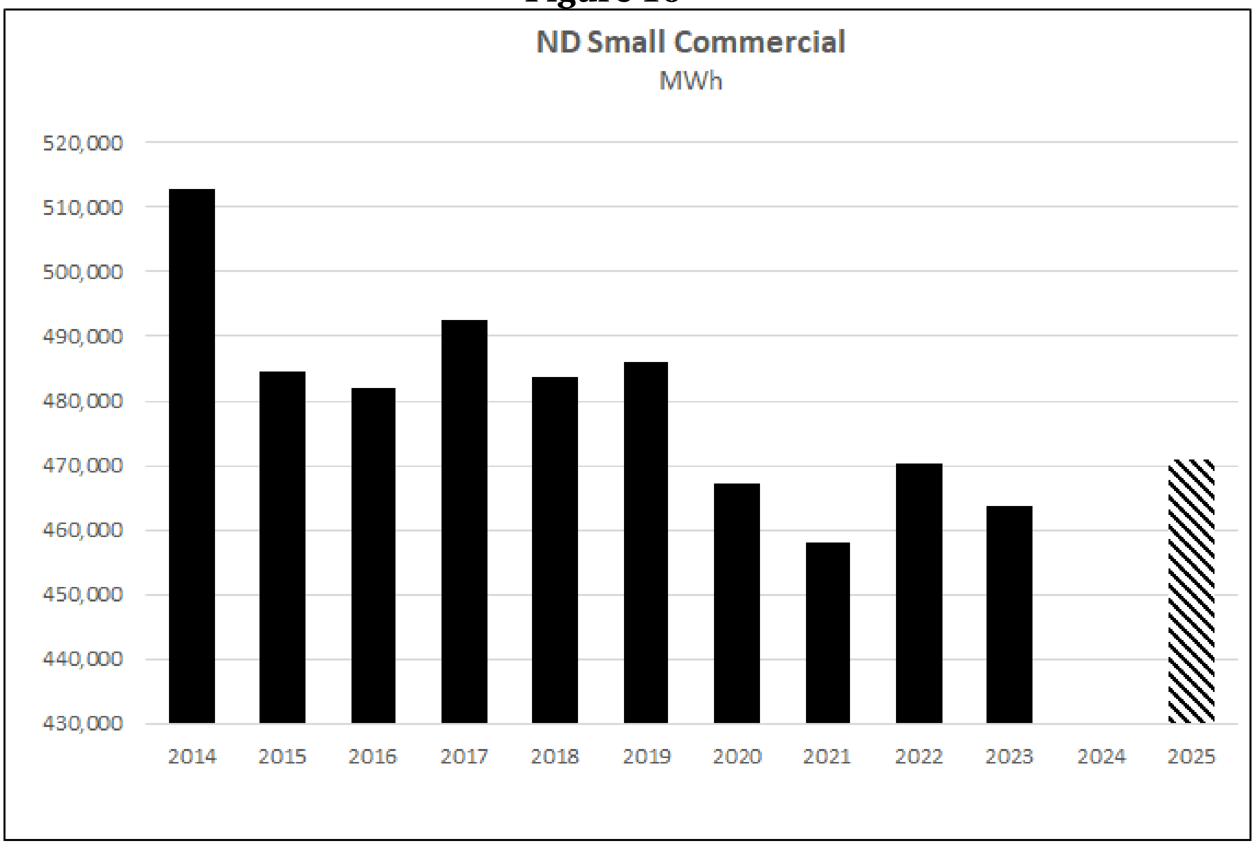
Figure 9



c) Small Commercial

The main forecasting variables used for the North Dakota Small Commercial class were weather and Gross Regional Product. Otter Tail expects to see some growth in sales in 2025 for this class. Figure 10 shows the historic weather normalized sales and 2025 forecasted sales for the Small Commercial class.

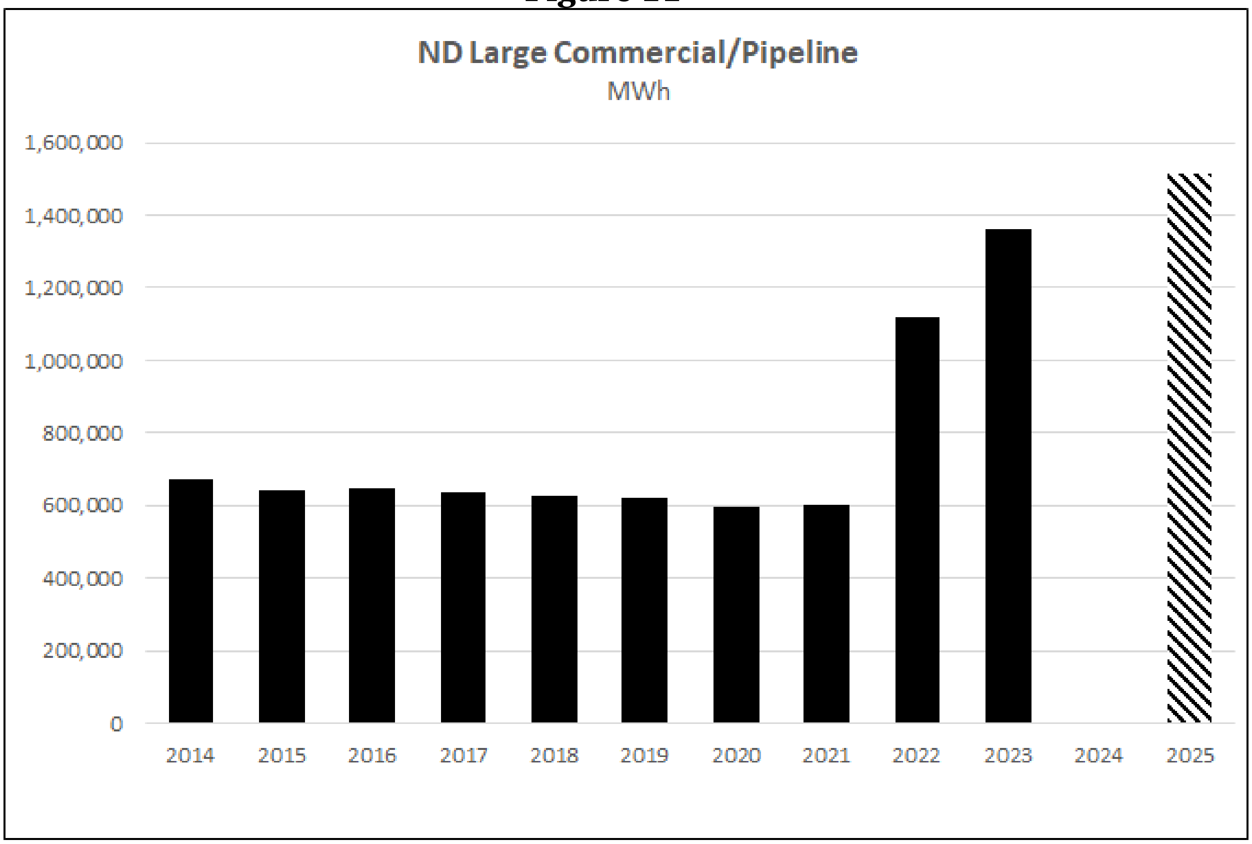
Figure 10



d) Large Commercial/Pipeline

Historical sales was used as a key predictor for the Large Commercial forecast. Pipelines are forecasted separately from the other Large Commercial customers, as described above. There was a significant increase in sales for this class in 2022 with the addition of new Large Commercial load and more new load expected through 2025. Figure 11 details the historic weather normalized sales and 2025 forecasted sales for the ND Large Commercial/Pipeline classes.

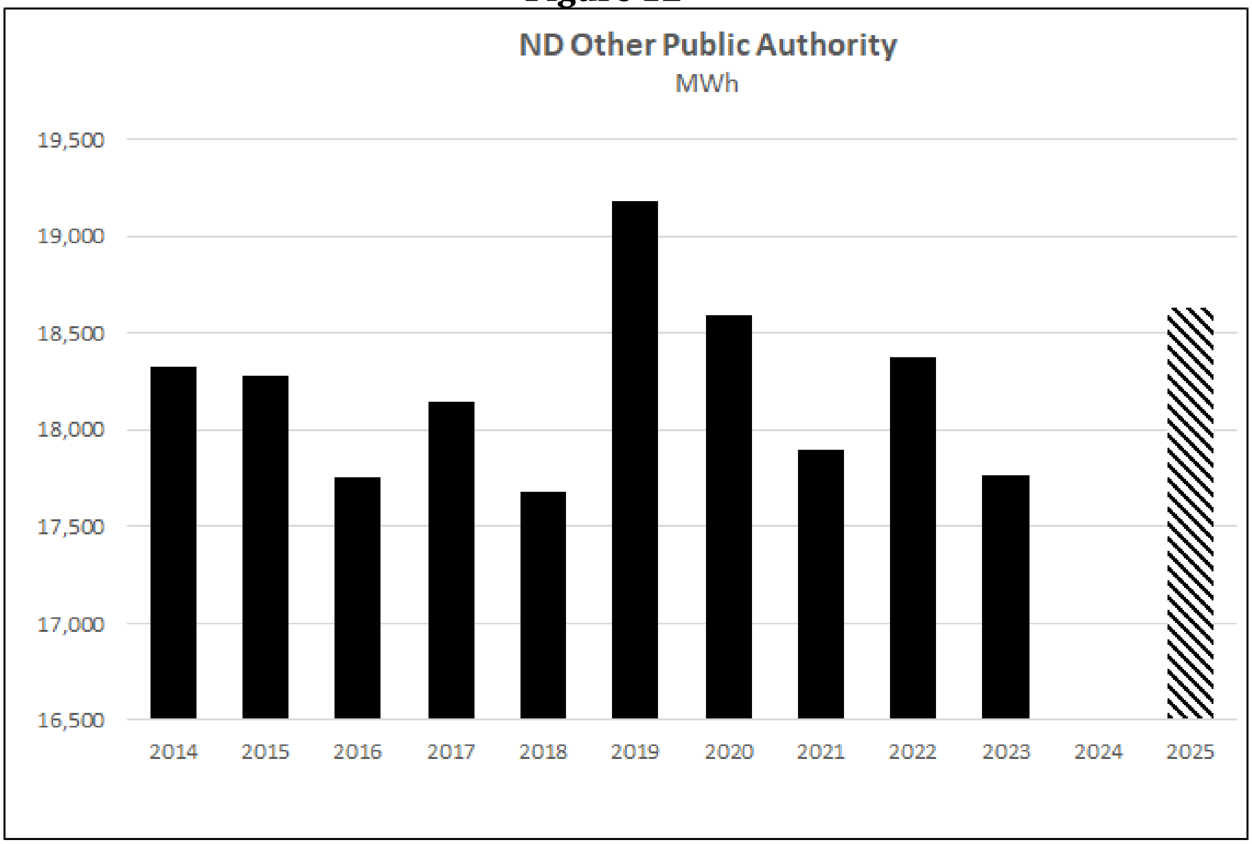
Figure 11



e) Other Public Authority (OPA)

Weather and a historical sales trend were the significant forecasting variables used for this class. Sales are forecast to be higher again, after a decrease in 2023. Refer to Figure 12 below for historic weather normalized sales and 2025 forecasted sales for the North Dakota OPA class.

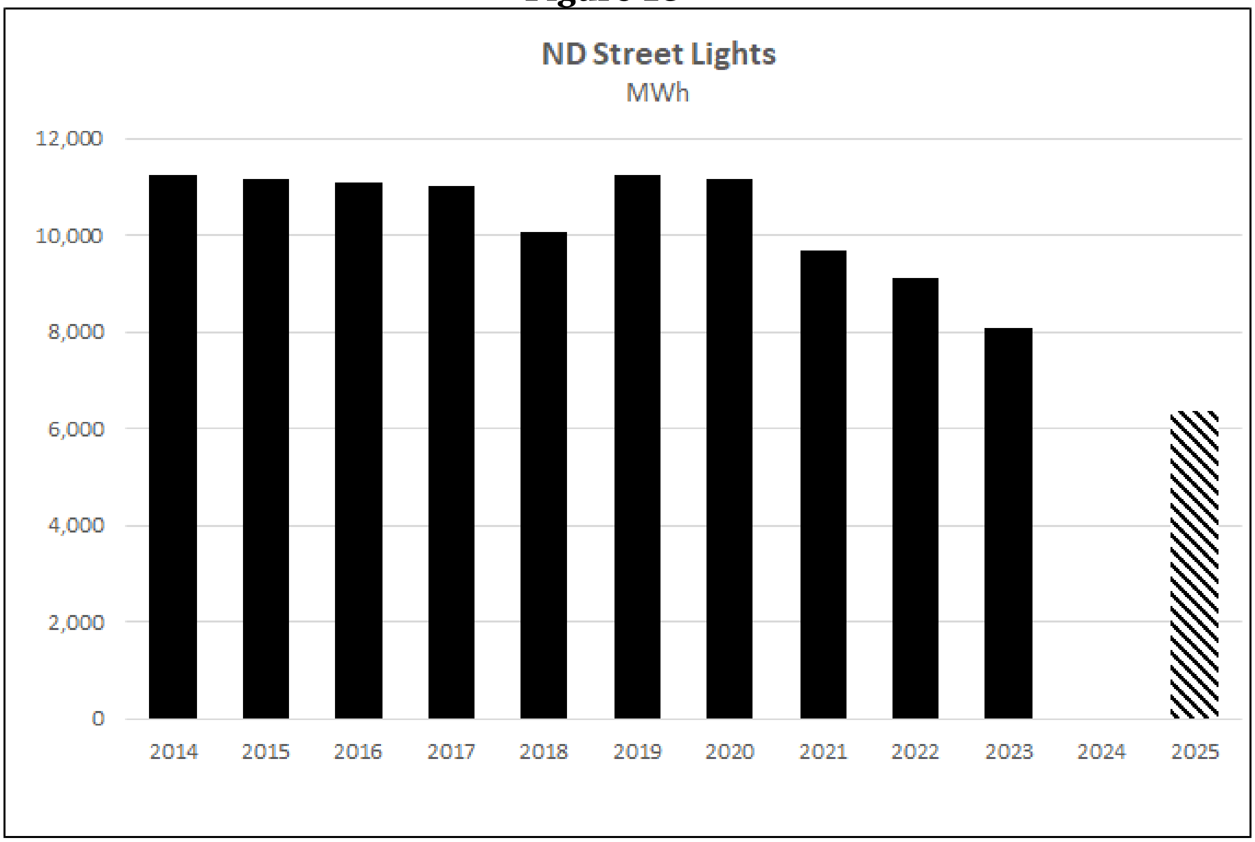
Figure 12



f) Street Lighting

Historically, Otter Tail's North Dakota Street Lighting forecast showed very little change over the past 20 years until recent year. There is currently an effort to switch street lighting to LED bulbs, which decreased kWh sales in 2021 and 2022 and is expected to continue that decrease into 2026. Figure 13 details the historic sales and 2025 sales forecast for this class.

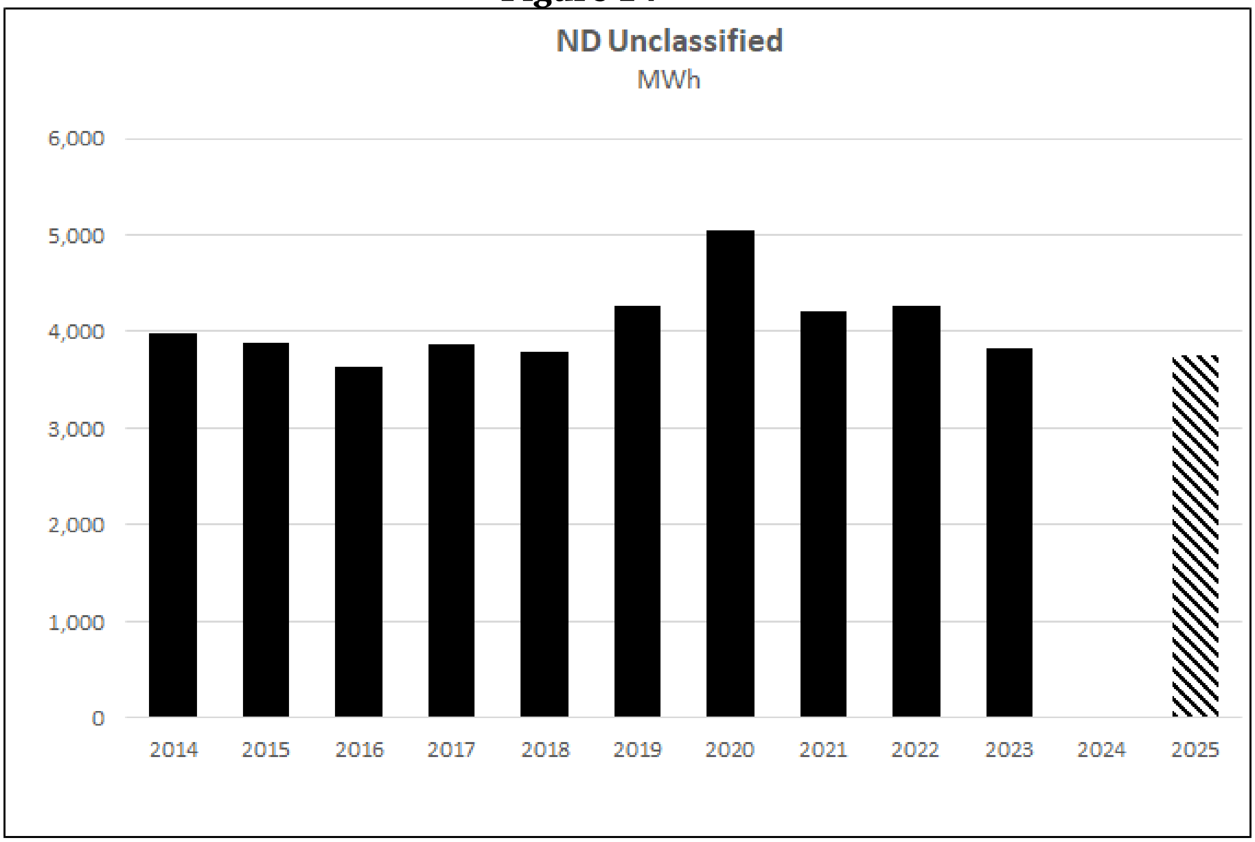
Figure 13



g) Unclassified

This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up less than 0.3 percent of Otter Tail's total kWh sales. See Figure 14 for the historic weather normalized sales and 2025 forecasted sales for this class.

Figure 14



South Dakota

a) Residential

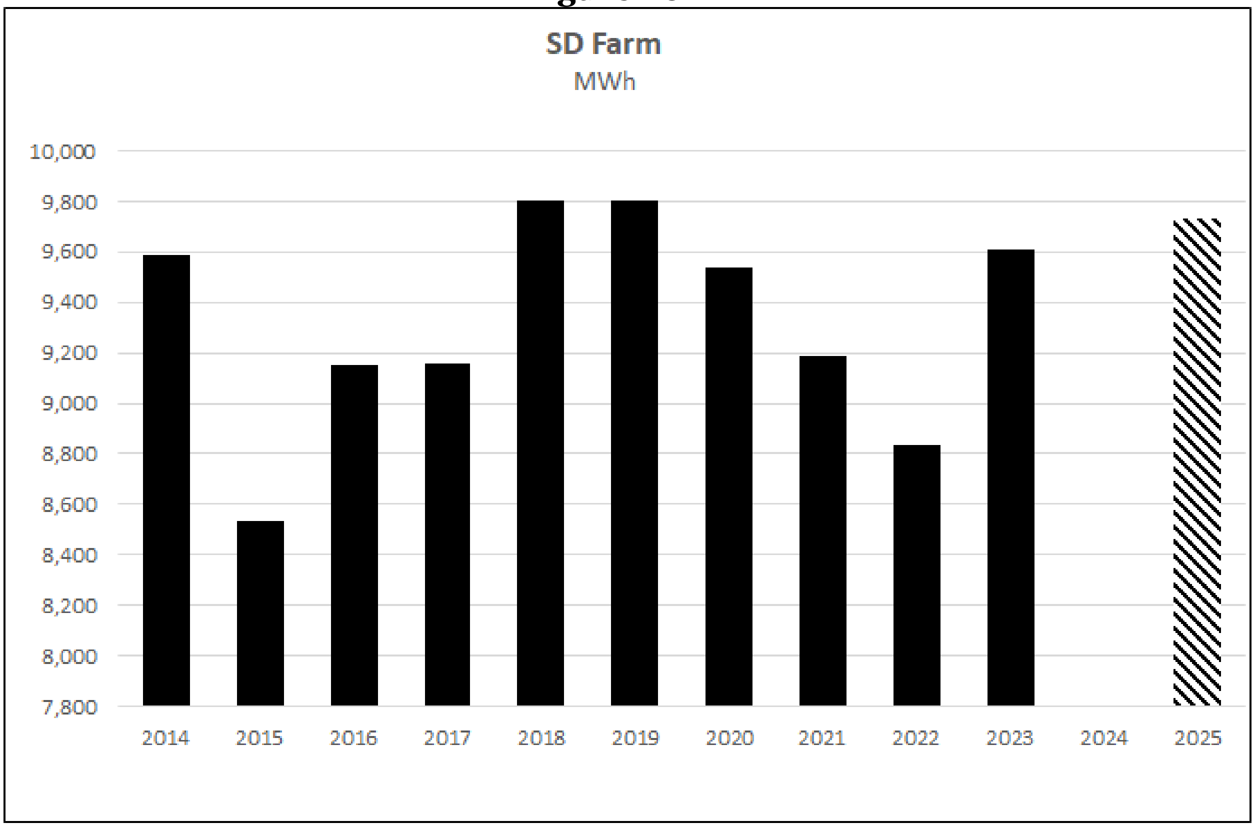
Otter Tail used weather and, once again, a Number of Household variable to forecast the 2025 South Dakota Residential sales. This class is extremely weather-sensitive, so weather is an important predictor of sales. Figure 15 shows the historic weather normalized sales and 2025 forecasted sales for the South Dakota Residential class.

Figure 15

b) Farms

Weather and a historical sales trend variable were the main predictors in the SD Farm class model. See Figure 16 for the historic weather normalized sales and 2025 forecasted sales for this class.

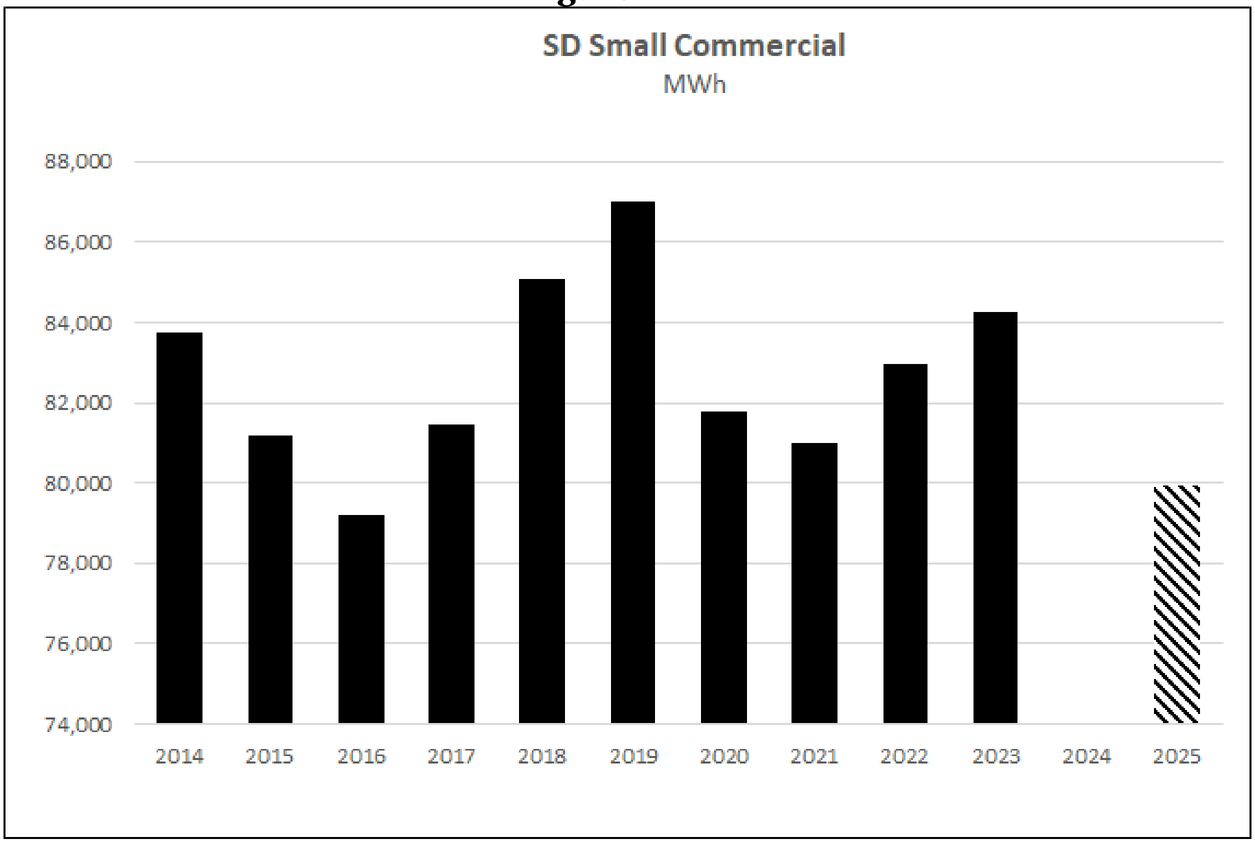
Figure 16



c) Small Commercial

In the South Dakota Small Commercial class, a historical sales trend and weather were used to predict sales. With the UPM declining due to efficiencies, the sales in this class is predicted to be lower in 2025. Figure 17 shows the historic weather normalized sales and 2025 forecasted sales for the Small Commercial class.

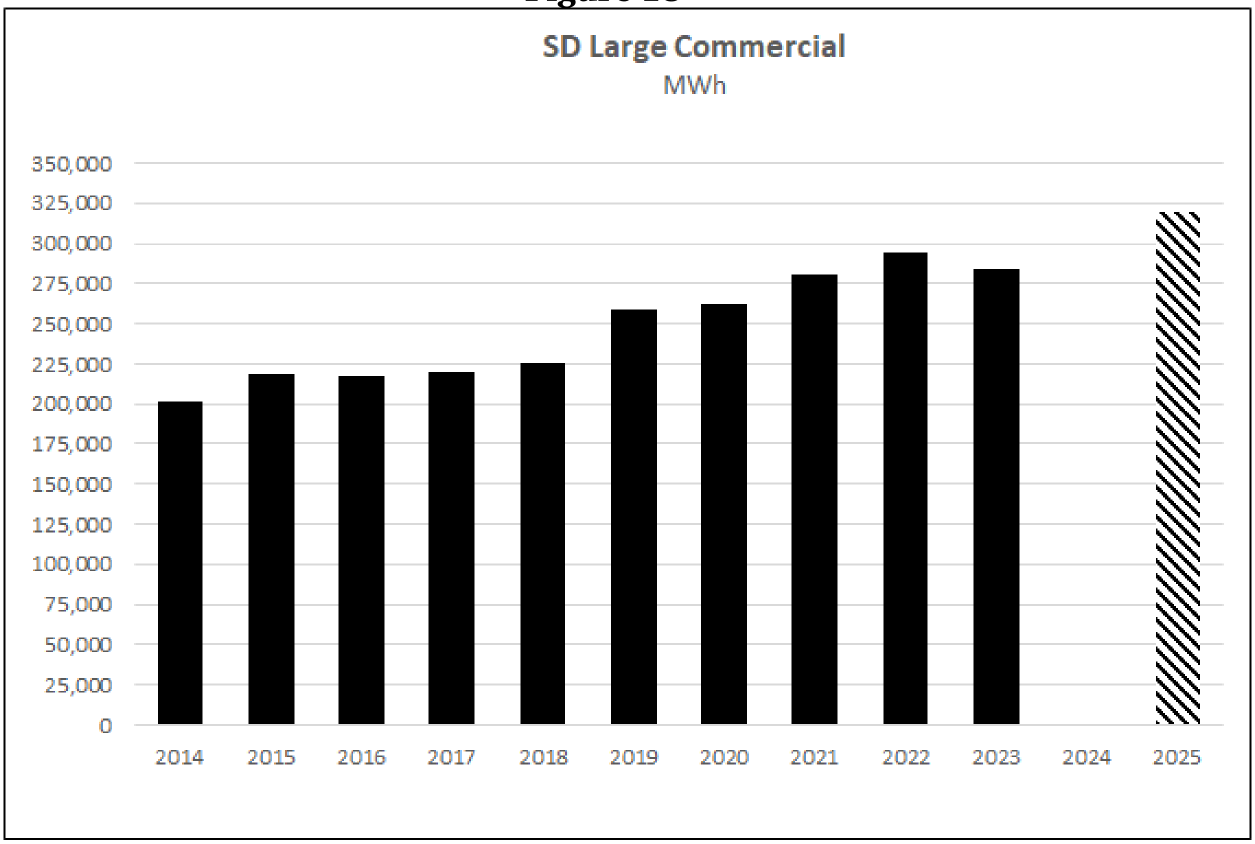
Figure 17



d) Large Commercial

The South Dakota Large Commercial class has experienced growth in recent years. Trend variables along with Gross Regional Product were used to represent growth in this class. Figure 18 details the historic weather normalized sales and 2025 forecasted sales for the Large Commercial class.

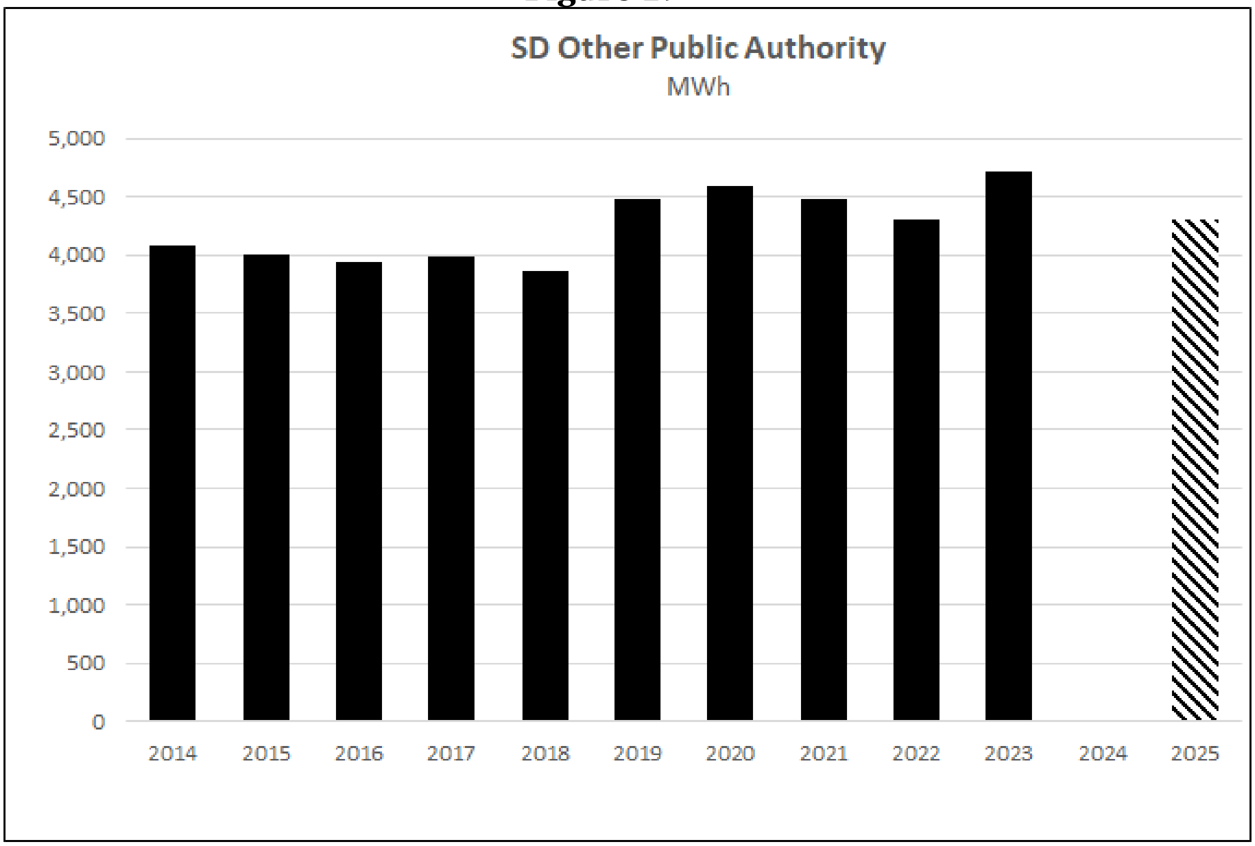
Figure 18



e) Other Public Authority (OPA)

The South Dakota OPA class is predicted to see a little decline in 2025 based on a historical sales trend. Refer to Figure 19 below for historic weather normalized sales and the 2025 forecasted sales for the OPA class.

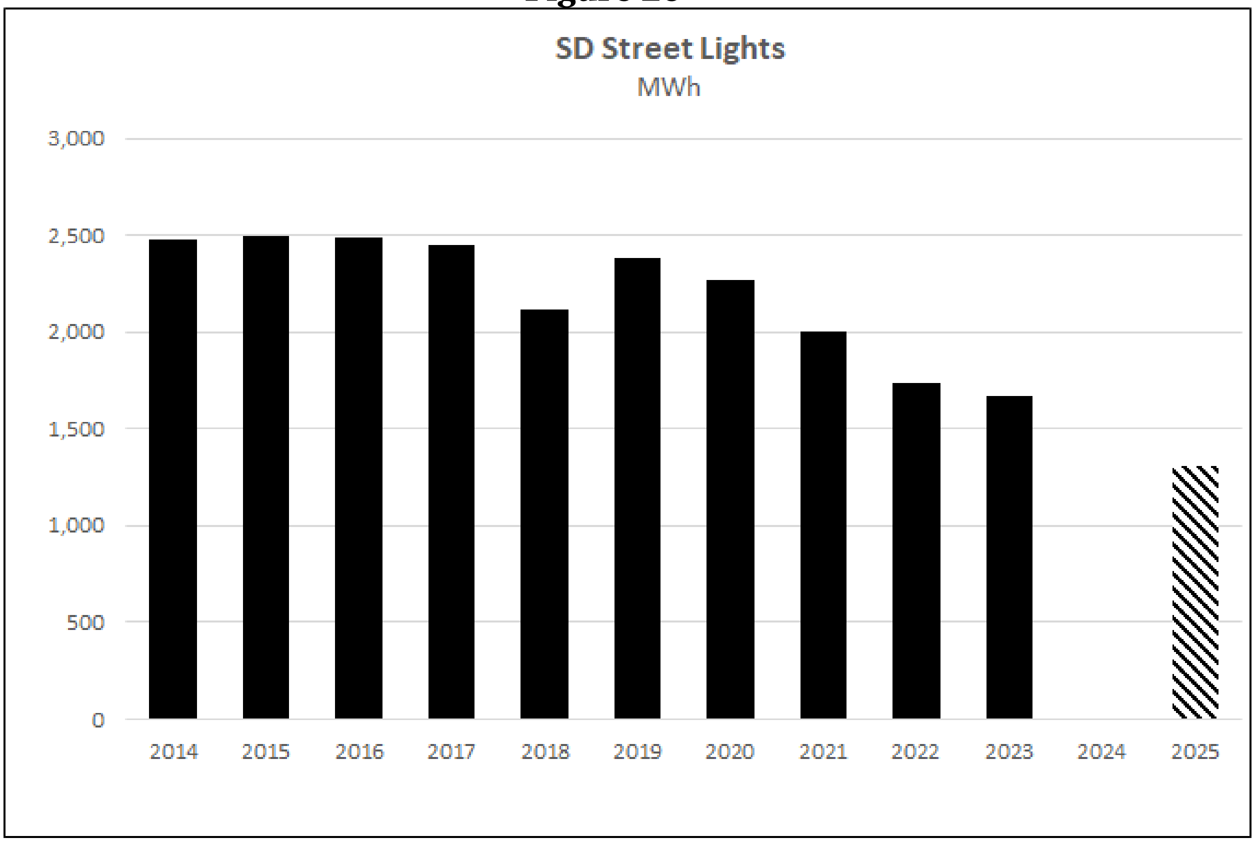
Figure 19



f) Street Lighting

Otter Tail's South Dakota Street Lighting sales have declined in recent years and is expected to continue into 2026 with the replacement of fixtures to LED bulbs. Figure 20 details the historic sales and 2025 forecasted sales for this class.

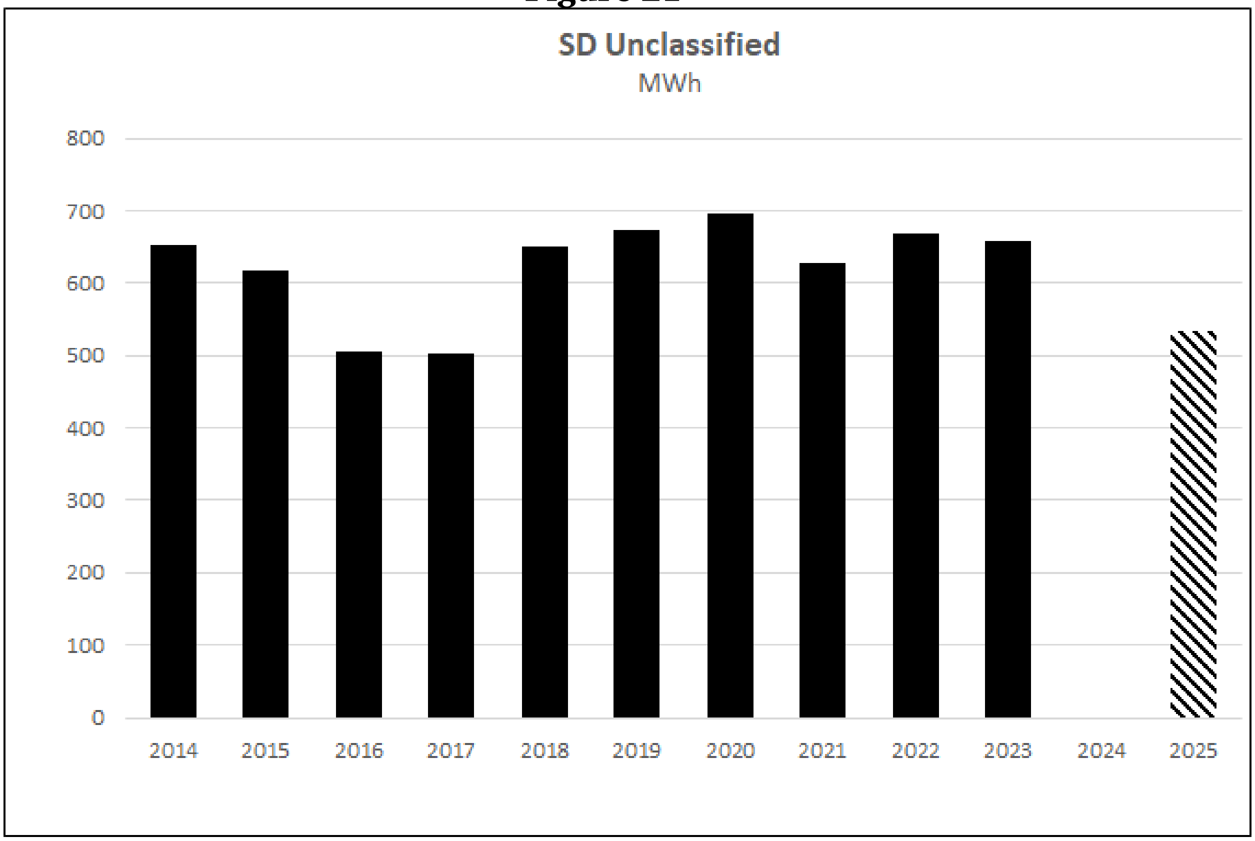
Figure 20



g) Unclassified

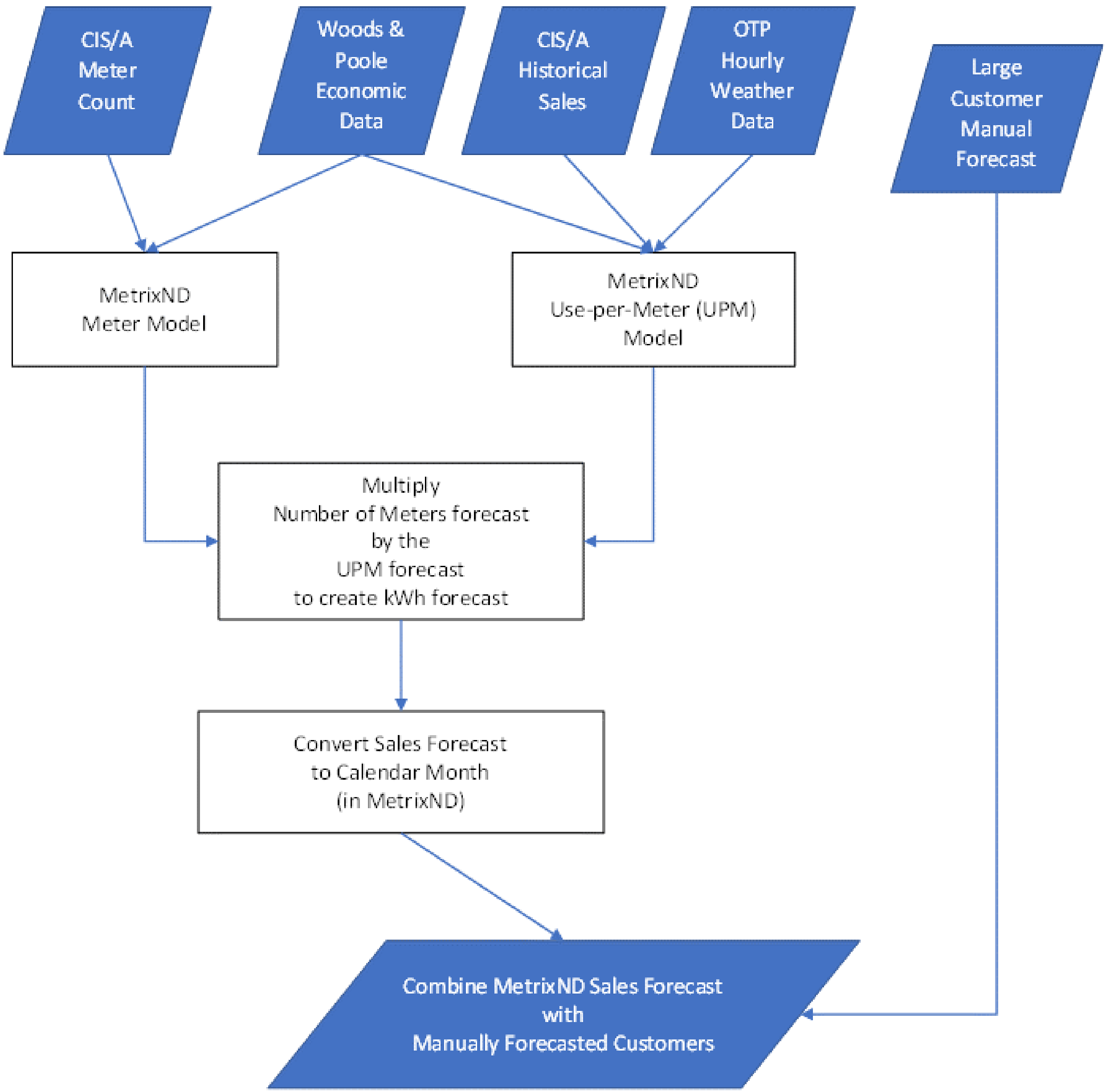
This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up less than 0.3 percent of Otter Tail's total kWh sales. See Figure 21 for the historic weather normalized sales and 2025 forecasted sales for this class.

Figure 21



Sales Model Description

The following flowchart is the process Otter Tail follows to create its sales forecast.



Meter Count Model

The meter count models, designed in MextrixND, forecast monthly meter counts by state and by class, based on historical meter counts, economic indicators and various binary variables. 2023 Woods and Poole (developed by Woods & Poole Economics, Inc. - http://www.woodsandpoole.com) data was used for all economic data variables. The variables most often used are Number of Households and Gross Regional Product.

Use-Per-Meter (UPM) Model

The UPM Models, also designed in Metrix ND, forecast estimated monthly UPM as a function of historical usage, weather conditions and binary variables. Weather conditions are represented using monthly heating degree days and cooling degree days (definitions to follow), with a base of 65 degrees for cooling and 55 degrees for heating. In some cases, binary variables are included in the equation to account for unique events in the historical period.

1. MODEL INPUTS

a) Sales and Meter Count Historical Data

Adjustments Made

Monthly kWh data was graphed, and values were checked for errors due to meters not being billed, being billed twice in one month, etc. As described in detail below, any bill adjustments are applied to the month in which the error occurred. In most cases corrections are found and downloaded during the following month's billing updates.

Detailed Information

Historical kWh data and the number of meters are read from Otter Tail's SAS CIS/A data sets. These SAS data sets are created from extracts of Otter Tail's Customer Information System (CIS), which are downloaded the first day of each month containing the prior month's billing data. The datasets include billing adjustments of prior bills to appropriately reflect actual usage and billing in the month of the original bill. Any changes made in Otter Tail's CIS are included in the CIS/A extract files, and the corrections are made to the month the error occurred (as opposed to the month the adjustment was made). For example, if a customer has a bill adjustment to their July bill, but the need for the adjustment was not determined or made in the CIS until December, the adjustment in the

CIS/A data set would adjust the July bill, not the December bill. Meter count and UPM are derived from this dataset.

b) Otter Tail Power Company's Weather Data

Adjustments Made

Otter Tail graphs hourly monitoring station temperatures each month after downloading the data. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Detailed Information

Otter Tail used 20 years of historical weather in its 2025 Sales Forecast. This weather was collected from 2004 through 2023, from 12 monitoring stations throughout Minnesota, North Dakota, and South Dakota. Otter Tail's service territory is broken up into 12 geographic divisions. There is one weather station in each of Otter Tail's 12 divisions so that the weather across Otter Tail's entire service territory is well represented.

The UPM forecast uses heating degree days (HDD) and cooling degree days (CDD) as inputs – values calculated from dry bulb temperatures in the weather data referenced above. For each weather station, an average dry bulb temperature is calculated for each day. The HDD are then calculated by subtracting the average daily temperature from 55 degrees (the base). For example, if the average temperature for the day is 30 degrees, the HDD for that day is 25 (55-30). CDD are calculated by subtracting 65 (the base) from the average daily temperature. For example, if the average daily temperature is 70 degrees, the CDD for that day is 5 (70-65).

To determine the HDD and CDD for Minnesota, the weather stations in Minnesota are weighted by sales and summed.

MN Daily Heating Degree Days=
[(Station 1 Sales/Total MN Sales)*Station 1 HDD]+
[(Station 2 Sales/Total MN Sales)*Station 2 HDD]+ …
[(Station 6 Sales/Total MN Sales)*Station 6 HDD]

MN Daily Cooling Degree Days=
[(Station 1 Sales/Total MN Sales)*Station 1 CDD]+
[(Station 2 Sales/Total MN Sales)*Station 2 CDD]+ …
[(Station 6 Sales/Total MN Sales)*Station 6 CDD]

This process is repeated for North Dakota and South Dakota.

Otter Tail creates HDD and CDD based on billing month weather and calendar month weather. The process is as follows:

1. *Billing Month HDD and CDD:*
   Daily HDD and CDD are added by billing cycle to determine the HDD and CDD for each cycle per month. Once a HDD and CDD value for each cycle and month is obtained, all the cycles are combined into one billing month, averaging the cycle HDD and the cycle CDD. An HDD value and a CDD value for each billing month have now been created.

   Next, Normal Billing HDD and CDD is calculated by averaging 20 years of monthly billing HDD and CDD. These values are used in the sales forecast.
2. *Calendar Month HDD and CDD:*
   Daily HDD and CDD are added by calendar month.

   Normal Calendar HDD and CDD are calculated by averaging 20 years of monthly Calendar HDD and CDD. These values are used in the sales forecast.

Otter Tail's sales forecast uses weather normalization principally to compare the sales forecast to weather normalized historical data. HDD and CDD may be used in all models with the exception of street lighting as that usage is not considered temperature sensitive. Most of Otter Tail's other customer classes have some level of weather sensitivity.

c) Woods & Poole Economics, Inc.

<u>Adjustments Made</u>

None

<u>Detailed Information</u>

In its 2025 sales forecast, Otter Tail used economic data from Woods & Poole Economics, Inc. Their database contains historical economic and demographic data through 2021 and forecast economic and demographic data through the year 2060. Otter Tail subscribes to this information by county to use in its meter models.

The sales forecast used the following variables from Woods & Poole:
•*Number of Households*
•*Farm Employment*
•*Gross Regional Product*
•*Net Earnings*

Otter Tail does not serve the entire load in the counties within its service territory. This is especially problematic when Otter Tail does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, North Dakota; Moorhead, Minnesota; Grand Forks, North Dakota and Minot, North Dakota. Otter Tail does not serve these larger cities, but it does serve small communities surrounding these larger ones. To reflect this, Otter Tail used econometric data only from counties where Otter Tail served at least 10 percent of the population of the county. County and City population data is downloaded from www.census.gov. The percentage of the population served in each county was determined by dividing the sum of population of the towns served by Otter Tail in each county by the population of the county. Towns to be used in the calculation were obtained from an internal database of towns served by Otter Tail Power Company. The data is then summed to the state level and graphed as a reasonability check. Annual Woods & Poole data is converted from annual data to monthly data by interpolating between annual values with a flat line.

As Otter Tail serves three states with economic differences, using econometric models makes it possible to utilize the different economic data pertinent for each state and determine whether particular variables are drivers for each state.

2. CALENDAR MONTH CALCULATION

Because historical usage data, in its purest form, is in billing month format, Otter Tail creates all models using billing month data. After creating billing month sales models, these models are adapted to calendar month. As weather generally only affects UPM, not the number of meters, the calendar month conversion is only applied to the UPM model. To create the calendar month UPM forecast, the calendar month HDD and CDD are substituted for the billing month HDD and CDD, resulting in a calendar month UPM forecast.

3. BINARY VARIABLES

All models that make up the sales forecast utilize binary variables. Monthly binary variables that account for seasonal differences are the most commonly used variables. Annual binary variables are used to account for the deviations in growth or consumption that are not expected in the calendar year. For example, the Large Commercial model uses binary variables starting in January 2011 to account for the change in meters from Small Commercial to Large Commercial. Other binary variables are utilized as necessary to improve the fit of the model and statistical significance of the economic and weather variables.

Locational Marginal Price Forecast ($/MWh)
Indiana Hub pricing provided by Intercontinental Exchange*
March 28, 2024

Line No.	(A) Month	(B) Indiana Hub Peak Forecast	(C) OTP.OTP Loadzone Peak Forecast	(D) Indiana Hub Off Peak Forecast	(E) OTP.OTP Loadzone Off Peak Forecast
1	**Jan-25**	55.10	60.95	43.10	51.85
2	**Feb-25**	43.90	50.70	35.00	43.90
3	**Mar-25**	40.50	41.50	31.75	35.05
4	**Apr-25**	40.00	38.67	27.50	28.22
5	**May-25**	42.95	41.98	28.35	28.29
6	**Jun-25**	47.50	46.06	29.40	29.82
7	**Jul-25**	66.40	64.62	38.50	37.75
8	**Aug-25**	59.35	58.70	33.50	33.25
9	**Sep-25**	48.80	48.75	30.15	31.94
10	**Oct-25**	45.50	44.69	31.85	33.04
11	**Nov-25**	47.45	45.40	38.25	38.23
12	**Dec-25**	53.30	55.65	45.10	49.10

*Source: ICE https://www.theice.com

provided by Intercontinental Exchange*
March 14, 2023

Line No.	(A) Month	(B) Ventura Hub ($/MMBtu)
1	Jan-25	5.9720
2	Feb-25	5.8585
3	Mar-25	3.2250
4	Apr-25	2.8305
5	May-25	2.8500
6	Jun-25	2.9735
7	Jul-25	3.1420
8	Aug-25	3.1540
9	Sep-25	2.9630
10	Oct-25	2.9770
11	Nov-25	3.7345
12	Dec-25	4.9945

*Source: ICE https://www.theice.com

Attachment 9

Clean Versions of

Tariff Sheet MN 13.01 – Energy Adjustment Rider

ENERGY ADJUSTMENT RIDER

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

There shall be added to or deducted from the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing kilowatt hours (kWh) by the billed Energy Adjustment Factor (EAF) per kWh (rounded to the nearest 0.001¢). The Current Period Cost of Energy shall be based upon the forecasted cost of energy for the current month, divided by all forecasted Kilowatt-Hour sales exclusive of intersystem sales for the current month. The applicable **C** adjustment will be applied to each Customer's bill beginning with the first day of the calendar month. The forecasted cost of energy shall be determined based on forecasted information for the following items:

1. The forecasted cost of fuel, as recorded in Account 151, used in the Company's generating plants based on the forecasted dispatch of those plants.

2. The forecasted energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of Capacity or Demand charges.

3. The forecasted net energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, whether or not those purchases occur on an economic dispatch basis, and all fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expense identified in 216B.1645, subd. 1(1), and subd. 1(2) to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691.

4. All forecasted Midwest ISO (MISO) and Southwest Power Pool (SPP) costs and revenues associated with forecasted retail sales that have been authorized by the Commission to flow through this Energy Adjustment Rider and excluding MISO and SPP costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

5. Renewable energy purchased for the Tail*Winds* program is not included in the cost of energy adjustment calculation.

6. The forecasted identifiable fuel costs associated with energy purchased for reasons other than in 2 and 3 above.

7. Less the forecasted fuel-related costs recovered through intersystem sales.

8. Less a credit for forecasted asset-based margins: forecasted revenues minus costs from asset-based wholesale energy and MISO ancillary services market ("ASM") transactions (excluding ancillary services net revenues derived through OTP's FERC-approved Control Area Services Operations Tariff) shall be credited to the cost of energy. The forecasted revenues for this calculation are those received from forecasted sales of excess generation; the forecasted costs are the fuel costs (as defined in FERC Account 501) and energy costs (including MISO costs that are booked to FERC Account 555) and any forecasted transmission costs incurred that are required to make such sales.

9. The forecasted costs of reagents for the Company to operate its generating plants in compliance with Federal Environmental Protection Agency rules and regulations.

10. The forecasted costs of fuel and reagents resulting from steam and water sales.

11. The proceeds from the forecasted revenues from steam and water sales shall be credited to (flow through) the energy adjustment rider.

12. Less a credit to provide Minnesota customers the full amount of avoided purchased power costs associated with 100 percent of the Hoot Lake Solar plant output. **N** **N**

13. Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or revenues will be credited (flow through) the energy adjustment rider. **N** **N**

CLASS ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each customer service category defined by customer class. The EAF for each service category is the sum of the Current Period forecasted Cost of Energy multiplied by the applicable EAF Ratio, and the applicable annual true-up.

Service Category	Section	EAF Ratio	
Residential	9.01, 9.02	1.0555	
Farm	9.03	1.0281	
General Service	10.01, 10.02, 10.03, 10.07	1.0461	
Large General Service non TOD	10.04, 10.06, 14.03	1.0207	**C**
Large General Service TOD – Winter On-Peak	10.05, 10.06, 11.01	1.2673	**C**
Large General Service TOD – Winter Shoulder	10.05, 10.06, 11.01	1.1106	**C**
Large General Service TOD – Winter Off-Peak	10.05, 10.06, 11.01	0.8499	**C**
Large General Service TOD – Summer On-Peak	10.05, 10.06, 11.01	1.2664	**C**
Large General Service TOD – Summer Shoulder	10.05, 10.06, 11.01	0.9956	**C**
Large General Service TOD – Summer Off-Peak	10.05, 10.06, 11.01	0.6896	**C**
Irrigation Service	11.02	0.9250	
Outdoor Lighting	11.03, 11.04, 11.07	0.8645	
OPA	11.05	1.0210	
Controlled Service Deferred Load	14.01, 14.06	0.9513	
Controlled Service Interruptible	14.04,	0.9883	
Controlled Service Off-Peak	14.07, 14.12	0.9164	

Forecasted Class EAF’s are published on OTP’s website at https://www.otpco.com/pricing.

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 per kWh to the forecasted costs per kWh 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 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 Minnesota 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 EAF ratio. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each class that will be added to or subtracted from the applicable forecasted class EAF's for the months the true-up factor is in effect and applied to Customers' bills as part of the monthly cost of Energy Adjustment Charge.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply and by any Voluntary Rate Riders selected by the Customer, unless otherwise noted in this schedule. See Sections 12.00, 13.00 and 14.00 of the Minnesota electric rates for the matrices of riders.

The Minnesota Public Utilities Commission approved monthly rates for our Energy Adjustment Rider. A rider is a charge for a specific feature, such as the cost of fuel. This rider pays for the cost of fuel we use to generate electricity to serve our customers, transportation costs for that fuel, and costs we incur to buy energy to supplement our own power plants. We established this rider in 1977 and currently apply it to customer bills monthly per kilowatt hour of energy used.

We've included 2025 monthly rates on this insert. Each customer class receives a separate Energy Adjustment Factor Rate to better reflect their cost of energy use.[1]

Approved 2025 Energy Adjustment Rider Rates ($/kWh)						
Service category	**JAN.**	**FEB.**	**MAR.**	**APRIL**	**MAY**	**JUNE**
Residential	$0.03075	$0.03195	$0.02614	$0.02762	$0.02653	$0.02328
Farm	$0.02995	$0.03112	$0.02546	$0.02690	$0.02584	$0.02267
General Service	$0.03048	$0.03166	$0.02591	$0.02737	$0.02629	$0.02307
Large General Service non TOD	$0.02974	$0.03089	$0.02528	$0.02671	$0.02566	$0.02251
Large General Service TOD – Winter On-Peak	$0.03692	$0.03836	$0.03139	$0.03316	$0.03185	
Large General Service TOD – Winter Shoulder	$0.03235	$0.03361	$0.02751	$0.02906	$0.02792	
Large General Service TOD – Winter Off-Peak	$0.02476	$0.02572	$0.02105	$0.02224	$0.02136	
Large General Service TOD – Summer On-Peak						$0.02793
Large General Service TOD – Summer Shoulder						$0.02196
Large General Service TOD – Summer Off-Peak						$0.01521
Irrigation Service	$0.02695	$0.02800	$0.02291	$0.02420	$0.02325	$0.02040
Outdoor Lighting	$0.02519	$0.02616	$0.02141	$0.02262	$0.02173	$0.01907
OPA	$0.02974	$0.03090	$0.02529	$0.02672	$0.02566	$0.02252
Controlled Service Deferred Load	$0.02771	$0.02879	$0.02356	$0.02489	$0.02391	$0.02098
Controlled Service Interruptible	$0.02879	$0.02991	$0.02448	$0.02586	$0.02484	$0.02180
Controlled Service Off-Peak	$0.02670	$0.02774	$0.02270	$0.02398	$0.02303	$0.02021

[1] We calculated these rates by multiplying the approved Energy Adjustment Rider Rate by the Class Energy Adjustment Factor Ratio.

Service category	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.
Residential	$0.02329	$0.02447	$0.02349	$0.02305	$0.02531	$0.03046
Farm	$0.02269	$0.02383	$0.02288	$0.02245	$0.02465	$0.02967
General Service	$0.02308	$0.02425	$0.02328	$0.02284	$0.02508	$0.03018
Large General Service non TOD	$0.02252	$0.02366	$0.02272	$0.02229	$0.02447	$0.02945
Large General Service TOD – Winter On-Peak				$0.02767	$0.03039	$0.03657
Large General Service TOD – Winter Shoulder				$0.02425	$0.02663	$0.03205
Large General Service TOD – Winter Off-Peak				$0.01856	$0.02038	$0.02452
Large General Service TOD – Summer On-Peak	$0.02795	$0.02936	$0.02818			
Large General Service TOD – Summer Shoulder	$0.02197	$0.02308	$0.02216			
Large General Service TOD – Summer Off-Peak	$0.01522	$0.01599	$0.01535			
Irrigation Service	$0.02041	$0.02144	$0.02059	$0.02020	$0.02218	$0.02669
Outdoor Lighting	$0.01908	$0.02004	$0.01924	$0.01888	$0.02073	$0.02494
OPA	$0.02253	$0.02367	$0.02272	$0.02229	$0.02448	$0.02946
Controlled Service Deferred Load	$0.02099	$0.02205	$0.02117	$0.02077	$0.02281	$0.02745
Controlled Service Interruptible	$0.02181	$0.02291	$0.02199	$0.02158	$0.02370	$0.02852
Controlled Service Off-Peak	$0.02022	$0.02125	$0.02039	$0.02001	$0.02197	$0.02644

For more information, contact Customer Service at **800-257-4044** or visit **otpco.com/MNEnergyAdjustment**.

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
January 2025 - December 2029

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		**Jan 2025**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
1	**2025**	**[PROTECTED DATA BEGINS . . .**												
2	MWh-Steam													
3	Hydro													
4	Wind/Solar													
5	Other													
6	Subtotal													
7	Purchases													
8	Total													
9														
10														
11	Cost-Steam													
12	Other													
13	Subtotal													
14	Purchases													
15	Total													
16														
17														
18	$/MWh-Steam													
19	Other													
20	Purchases													
21	Total													
22														
23														
24	MWh Allocation													
25	Steam													
26														
27	Purchased Power													
28														**. . . PROTECTED DATA ENDS]**

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
January 2025 - December 2029

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		**Jan 2026**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
1	**2026**	**[PROTECTED DATA BEGINS . . .**												
2	MWh-Steam													
3	Hydro													
4	Wind/Solar													
5	Other													
6	Subtotal													
7	Purchases													
8	Total													
9														
10														
11	Cost-Steam													
12	Other													
13	Subtotal													
14	Purchases													
15	Total													
16														
17														
18	$/MWh-Steam													
19	Other													
20	Purchases													
21	Total													
22														
23														
24	MWh Allocation													
25	Steam													
26														
27	Purchased Power													
28														
														. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
January 2025 - December 2029

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		**Jan 2027**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
1	**2027**	**[PROTECTED DATA BEGINS . . .**												
2	MWh-Steam													
3	Hydro													
4	Wind/Solar													
5	Other													
6	Subtotal													
7	Purchases													
8	Total													
9														
10														
11	Cost-Steam													
12	Other													
13	Subtotal													
14	Purchases													
15	Total													
16														
17														
18	$/MWh-Steam													
19	Other													
20	Purchases													
21	Total													
22														
23														
24	MWh Allocation													
25	Steam													
26														
27	Purchased Power													
28														
														. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
January 2025 - December 2029

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		**Jan 2028**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
1	**2028**	**[PROTECTED DATA BEGINS . . .**												
2	MWh-Steam													
3	Hydro													
4	Wind/Solar													
5	Other													
6	Subtotal													
7	Purchases													
8	Total													
9														
10														
11	Cost-Steam													
12	Other													
13	Subtotal													
14	Purchases													
15	Total													
16														
17														
18	$/MWh-Steam													
19	Other													
20	Purchases													
21	Total													
22														
23														
24	MWh Allocation													
25	Steam													
26														
27	Purchased Power													
28														
													. . . PROTECTED DATA ENDS]	

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
January 2025 - December 2029

Line No.	(A)	(B) Jan 2029	(C) Feb	(D) Mar	(E) Apr	(F) May	(G) Jun	(H) Jul	(I) Aug	(J) Sep	(K) Oct	(L) Nov	(M) Dec	(N) Total
1	**2028**	**[PROTECTED DATA BEGINS . . .**												
2	MWh-Steam													
3	Hydro													
4	Wind/Solar													
5	Other													
6	Subtotal													
7	Purchases													
8	Total													
9														
10														
11	Cost-Steam													
12	Other													
13	Subtotal													
14	Purchases													
15	Total													
16														
17														
18	$/MWh-Steam													
19	Other													
20	Purchases													
21	Total													
22														
23														
24	MWh Allocation													
25	Steam													
26														
27	Purchased Power													
28														**. . . PROTECTED DATA ENDS]**

Table A - $

Line	Acct	Description	2025fx	2023	2022	2021	3-YR Average	Variance	% Variance from 3-YR Average	Notes: Explanation of variances greater than 5% provided in footnotes below
	Plant Generation		[PROTECTED DATA BEGINS...							
1		Big Stone								
2		Coyote								
3		Hoot Lake #2								2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
4		Hoot Lake #3								2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
5							...PROTECTED DATA ENDS]			
6		**Total Coal**	**$ 51,353,826**	**$ 43,373,589**	**$ 44,363,283**	**$ 41,891,976**	**$ 43,209,616**			
7			[PROTECTED DATA BEGINS...							
8		Langdon Wind								
9		Ashtabula Wind								
10		Ashtabula III								Owned by OTP in January 2023
11		Luverne Wind								
12		Merricourt								Merricourt went into service in Q4 2020
13							...PROTECTED DATA ENDS]			
14		**Total Wind**	$ -		$ -	$ -	$ -			
15										
16		**Total Hydro**	$ -		$ -	$ -	$ -			
17			[PROTECTED DATA BEGINS...							
18		Jamestown 1								
19		Jamestown 2								
20		Lake Preston								
21							...PROTECTED DATA ENDS]			
22		**Total Oil - Peaking Units**	**$ 246,353**	**$ 443,227**	**$ 479,355**	**$ 872,315**	**$ 598,299**			
23			[PROTECTED DATA BEGINS...							
24		Natural gas - Solway								
25		Natural gas - Astoria								Astoria Station went into service in 2021
26		**Total Natural Gas**								Total Natural Gas needs to be protected because Solway is the only plant for 2018-2
27							...PROTECTED DATA ENDS]			
28			[PROTECTED DATA BEGINS...							
29		Solar - Hoot Lake Solar								In service in 2023
30		Solar - Blue Jay								
31		Solar - Blue Heron								
32							...PROTECTED DATA ENDS]			
33		**Total Solar**	$ -		$ -	$ -	$ -			
34										
35		**Total OTP-Owned**	**$ 67,931,785**	**$ 59,966,575**	**$ 64,941,756**	**$ 59,326,596**	**$ 62,134,176**	**$ 5,797,609**	**9%**	(1)
36			$ -							
37	Wholesale Market Charges									
38		**MISO Wholesale Market Charges**								
39	555.02	DA Asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
40	555.04	DA FBT Loss Amount	$ -	$ -	$ -	$ -	$ -			
41	555.09	DA Non-asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
42	555.19	RT Asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
43	555.24	RT Distribution of Losses Amount	$ (3,905,053)	$ (2,783,579)	$ (5,293,962)	$ (3,045,446)	$ (4,169,704)			
44	555.21	RT FBT Loss Amount	$ -	$ -	$ -	$ -	$ -			
45		DA Loss Amount	$ 7,405,629	$ 7,102,864	$ 13,335,954	$ 8,944,691	$ 11,140,322			
46		RT Loss Amount	$ 446,204	$ 579,669	$ 607,649	$ 323,549	$ 465,599			
47	555.26	RT Non-Asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
48	555.08	DA Losses Rebate on Option B GFA	$ -	$ -	$ -	$ -	$ -			
49	555.12	DA Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -			
50	555.32	RT Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -			
51	555.01	DA Mkt Admin Amount	*$ 850,121*	*$ 800,693*	*$ 735,641*	*$ 679,115*	$ 707,378			Excluded from Total MISO Wholesale Market Charges - Not MN EAR Applicable
52	555.18	RT Mkt Admin Amount	*$ 127,018*	*$ 106,591*	*$ 101,683*	*$ 96,301*	$ 98,992			Excluded from Total MISO Wholesale Market Charges - Not MN EAR Applicable
53	555.13	FTR Mkt Admin Amount	*$ 21,848*	*$ 19,664*	*$ 25,821*	*$ 24,908*	$ 25,364			Excluded from Total MISO Wholesale Market Charges - Not MN EAR Applicable
54	555.03	DA FBT Congestion Amount	$ -	$ -	$ -	$ -	$ -			
55		DA Congestion	$ 25,176,241	$ 25,896,159	$ 33,348,742	$ 26,685,319	$ 30,017,030			
56	555.20	RT FBT Congestion Amount	$ -	$ -	$ -	$ -	$ -			
57		RT Congestion	$ 2,953,142	$ 3,641,167	$ 2,760,582	$ 2,383,599	$ 2,572,091			
58	555.14	FTR Hourly Allocation Amount	$ (38,048,602)	$ (46,533,299)	$ (58,450,965)	$ (41,854,342)	$ (50,152,653)			
59	555.15	FTR Monthly Allocation Amount	$ (910,360)	$ (1,313,006)	$ (1,304,357)	$ (1,061,908)	$ (1,183,132)			
60	555.17	FTR Yearly Allocation Amount	$ (312,193)	$ (61,726)	$ (531,221)	$ (50,972)	$ (291,097)			
61	555.35	FTR Monthly Transaction Amount	$ -	$ -	$ -	$ (2,253,290)	$ (1,126,645)			
62	555.36	FTR Full Funding Guarantee Amount	$ (751,420)	$ (1,747,527)	$ 673,178	$ (739,519)	$ (33,171)			
63	555.37	FTR Guarantee Uplift Amount	$ 668,376	$ 1,672,331	$ (716,186)	$ 807,315	$ 45,564			
64	555.39	FTR Auction Revenue Rights Transaction Amount	$ (62,818,060)	$ (61,607,487)	$ (57,544,227)	$ (14,896,632)	$ (36,220,429)			
65	555.38	FTR Annual Transaction Amount	$ 61,353,684	$ 59,602,059	$ 57,509,852	$ 14,796,015	$ 36,152,934			
66	555.40	FTR Auction Revenue Rights Infeasible Uplift Amount	$ 154,551	$ 138,297	$ 174,184	$ 121,070	$ 147,627			
67	555.41	FTR Auction Revenue Rights Stage 2 Distribution Amount	$ (1,681,880)	$ (1,922,625)	$ (988,659)	$ (673,981)	$ (831,320)			
68	555.07	DA Congestion Rebate on Option B GFA	$ -	$ -	$ -	$ -	$ -			
69	555.10	DA Revenue Sufficiency Guarantee Distribution Amount	$ 173,493	$ 117,632	$ 221,984	$ 165,608	$ 193,796			
70	555.11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ (138,566)	$ (64,283)	$ (118,793)	$ (76,737)	$ (97,765)			
71	555.29	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 339,449	$ 134,826	$ 571,397	$ 1,147,485	$ 859,441			
72	555.30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ (2,348,157)	$ -	$ -	$ -	$ -			
73	555.42	RT Price Volatility Make Whole Payment	$ (649,241)	$ (472,047)	$ (735,455)	$ (544,832)	$ (640,144)			
74	555.28	RT Revenue Neutrality Uplift Amount	$ 1,541,475	$ 1,769,276	$ 996,307	$ 1,116,536	$ 1,056,421			
75	555.25	RT Misc Amount	$ (240,614)	$ 9,949	$ 123,204	$ (4,876)	$ 59,164			
76	555.27	RT Net Inadvertent Amount	$ 1,341	$ (46,925)	$ 70,182	$ (39,964)	$ 15,109			
77	555.31	RT Uninstructed Deviation Amount	$ -	$ -	$ -	$ 40,003	$ 20,002			
78	555.59	RT Demand Response Allocation Uplift Amount	$ 113,750	$ 20,303	$ 271,966	$ 357,473	$ 314,719			
79	555.63	DA Ramp Product	$ (41,891)	$ (43,204)	$ (42,843)	$ (20,847)	$ (31,845)			
80	555.64	RT Ramp Product	$ (11,518)	$ (6,659)	$ (18,196)	$ (8,203)	$ (13,200)			
81	555.65	RT Schedule 49 Cost Distribution Amount	$ 264,452	$ 314,584	$ 185,990	$ 81,263	$ 133,626			RT Schedule 49 Cost Distribtion is a new charge type as of 2020
82	555.55	RT ASM Non-Excessive Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
83	555.56	RT ASM Excessive Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
84	555.05	DA Congestion Rebate on COGA	$ -	$ -	$ -	$ -	$ -			
85	555.06	DA Losses Rebate on COGA	$ -	$ -	$ -	$ -	$ -			
86	555.22	RT Congestion Rebate on COGA	$ -	$ -	$ -	$ -	$ -			
87	555.23	RT Loss Rebate on COGA	$ -	$ -	$ -	$ -	$ -			
88		Net Congestion and Losses Adjustment & No DA Generation Schedule		$ 165,261	$ 462,699	$ 1,068,049	$ 765,374			
89		Settlement with another utility in Otter Tail's LBA								
90		**Total MISO Wholesale Market Charges**	**$ (11,265,769)**	**$ (15,437,990)**	**$ (14,430,995)**	**$ (7,233,575)**	**$ (10,832,285)**	**$ (433,484)**	**4%**	Total Excludes Schedule 16 and 17 (Lines 52, 53, 54 Above) (2)
91										
92		**SPP Wholesale Market Charges**		$ -						
93	555.19	DA Asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
94	555.03	DA Non-asset Energy Amount	$ -	$ -	$ -	$ -	$ -			
95	555.09	RT Asset Energy Amount***	$ -	$ -	$ -	$ -	$ -			Energy Amounts - included/embedded within Market Purchases
96	555.09	RT Non-Asset Energy Amount	$ -	$ -	$ -	$ -	$ -			
97	555.02	DA Make-Whole-Payment Distribution Amount								
98	555.10	RT Make-Whole-Payment Distribution Amount	$ 13,105	$ 128	$ 25,970	$ 1,026	$ 13,498			
99	555.18	RT Revenue Sufficiency Guarantee Distribution Amount	$ -	$ -	$ -	$ -	$ -			
100	555.15	RT Revenue Neutrality Uplift Distribution Amount	$ 2,925	$ 39	$ 5,728	$ 211	$ 2,970			
101	555.04	DA Regulation-Down Distribution Amount	$ 188	$ 11	$ 354	$ 68	$ 211			
102	555.05	DA Regulation-Up Distribution Amount	$ 703	$ 28	$ 1,357	$ 172	$ 765			
103	555.06	DA Spinning Reserve Distribution Amount	$ 860	$ 27	$ 1,658	$ 166	$ 912			
104	555.07	DA Supplemental Reserve Distribution Amount	$ 127	$ 4	$ 246	$ 9	$ 128			
105	555.08	RT Contingency Reserve Deployment Failure Amount	$ (22)	$ (0)	$ (45)	$ (0)	$ (23)			
106	555.11	RT Over-Collected Losses Distribution Amount	$ (200,436)	$ (151,084)	$ (269,406)	$ (952,666)	$ (611,036)			
107	555.12	RT Regulation-Down Distribution Amount	$ 34	$ 1	$ 70	$ 4	$ 37			
108	555.13	RT Regulation Non-Performance Distribution Amount	$ (25)	$ (1)	$ (46)	$ (6)	$ (26)			
109	555.14	RT Regulation-Up Distribution Amount	$ (40)	$ (0)	$ (50)	$ (24)	$ (37)			
110	555.16	RT Spinning Reserve Distribution Amount	$ (9)	$ (3)	$ (1)	$ (22)	$ (12)			
111	555.17	RT Supplemental Reserve Distribution Amount	$ (38)	$ 0	$ (74)	$ 1	$ (37)			
112	555.20	RT Pseudo Tie Congestion Amount	$ (398,761)	$ 1,290,849	$ (2,634,367)	$ (943,152)	$ (1,788,759)			
113	555.21	RT Pseudo Tie Loss Amount	$ (150,648)	$ 57,379	$ (452,993)	$ (414,729)	$ (433,861)			
114	555.23	Miscellaneous Amount	$ 113	$ (3)	$ (12)	$ 80	$ 34			
115	555.26	ARR Closeout Yearly Amount	$ (236,796)	$ (279,464)	$ (194,122)	$ (83,245)	$ (138,684)			
116	555.28	RT Demand Reduction Distribution Amount	$ 1	$ 0	$ 2	$ -	$ 1			New SPP Charge Type in 2020
117	555.29	RT Schedule 1A3 Amount	$ 87	$ 6	$ 165	$ 20	$ 93			New SPP Charge Type in 2021
118	555.3	RT Schedule 1A4 Amount	$ 425	$ 27	$ 807	$ 105	$ 456			New SPP Charge Type in 2021
119	555.01	DA GFA Carve Out Distribution Deployment Daily Amount	$ 426	$ 3	$ 620	$ 74	$ 347			
120	555.22	DA GFA Carve Out Distribution Deployment Monthly Amount	$ (7)	$ -	$ (3)	$ 4	$ 1			
121	555.27	DA GFA Carve Out Distribution Deployment Yearly Amount	$ (32)	$ (0)	$ (28)	$ (52)	$ (40)			
122	555.31	DA Ramp-Up Distribution Amount	$ (359,974)	$ (3)	$ 814					New SPP Charge Type in 2022
123	555.32	DA Ramp Down Distribution Amount		$ -	$ -					New SPP Charge Type in 2022
123	555.33	RT Ramp Capability Non-Performance Distribution Amount	$ -	$ (6)	$ (12)					New SPP Charge Type in 2022
124	555.34	RT Ramp Capability Up Distribution Amount	$ 313	$ (0)	$ (58)					New SPP Charge Type in 2022
125	555.35	RT Ramp Down Distribution Amount	$ (2)	$ (227)	$ -					New SPP Charge Type in 2022
126	555.36	ARR Daily Amount	$ (125)							New SPP Charge Type in 2024
127		**Total SPP Wholesale Market Charges**	**$ (1,327,608)**	**$ 917,700**	**$ (3,513,429)**	**$ (2,391,957)**	**$ (2,952,693)**	**$ 1,625,085**	**-55%**	(3)
128										
129		**MISO ASM**								
130		Day Ahead Regulation Amount	$ (423,667)	$ (516,907)	$ (323,596)	$ (463,671)	$ (393,634)			
131		Real Time Regulation Amount	$ (121,290)	$ (106,884)	$ (99,830)	$ (8,889)	$ (54,359)			
132		Regulation Cost Distribution Amount	$ 245,873	$ 222,692	$ 285,746	$ 241,102	$ 263,424			
133		Day Ahead Short-Term Reserve Amount	$ (350,553)	$ (310,068)	$ (202,945)	$ (15,814)	$ (109,380)			New ASM Charge Type in 2021
134		Real Time Short-Term Reserve Amount	$ (45,636)	$ (8,863)	$ (83,389)	$ 3,965	$ (39,712)			New ASM Charge Type in 2021
135		Real Time Short-Term Reserve Cost Distribution Amount	$ 239,214	$ 223,297	$ 200,059	$ 8,858	$ 104,459			New ASM Charge Type in 2021
136		Real Time Short-Term Reserve Deplovent Failure Charge Amount	$ -	$ (240,931)	$ (443,521)	$ -	$ (221,760)			New ASM Charge Type in 2021
137		Day Ahead Spinning Reserve Amount	$ (305,630)	$ (38,369)	$ (83,199)	$ (412,246)	$ (247,723)			
138		Real Time Spinning Reserve Amount	$ (73,489)	$ 192,445	$ 257,614	$ 100,198	$ 178,906			
139		Spinning Reserve Cost Distribution Amount	$ 222,228	$ (136,872)	$ (264,153)	$ 233,342	$ (15,406)			
140		Day Ahead Supplemental Reserve Amount	$ (200,347)	$ 58,349	$ 345,936	$ (488,347)	$ (71,206)			
141		Real Time Supplemental Reserve Amount	$ 199,013	$ 29,283	$ 41,021	$ 107,447	$ 74,234			
142		Supplemental Reserve Cost Distribution Amount	$ 34,786	$ -	$ 81,185	$ 81,278	$ 81,231			
143		Contingency Reserve Deployment Failure Charge Amount	$ 40,593	$ 75,947	$ 18,232	$ 573	$ 9,402			
144		Real Time Excessive Deficient Energy Deployment Charge Amount	$ 47,147	$ -	$ -	$ 33,772	$ 16,886			
145		Net Regulation Adjustment Amount	$ 17,267	$ 22,373	$ 9,412	$ 17,941	$ 13,676			
146		**Total MISO ASM**	**$ (474,493)**	**$ (534,506)**	**$ (261,428)**	**$ (560,492)**	**$ (410,960)**	**$ (63,533)**	**15%**	(4)
147										
148		**Total Wholesale Market Charges**	**$ (13,067,870)**	**$ (15,054,796)**	**$ (18,205,852)**	**$ (10,186,025)**	**$ (14,195,939)**			
149										
150										
151	Purchased Power									
152			[PROTECTED DATA BEGINS...							
153		Edgeley PPA								
154		Langdon PPA								
155		Ashtabula III PPA								Forecasted to be OTP-Owned in 2023
156		Tribal (WAPA)								Not Applicable to EAR - Excluded from Total
157		WAPA Energy Imbalance								Load balancing amounts between OTP and WAPA
158		Shared Loads								
159		Small Co-gen								
160		Bilateral purchases								
161		Market Purchases								MISO and SPP Energy
162							...PROTECTED DATA ENDS]			
163		**Total Purchases**	**$ 96,130,445**	**$ 92,485,212**	**$ 119,095,331**	**$ 69,581,124**	**$ 94,338,228**	**$ 1,792,217**	**2%**	Tribal (WAPA) excluded from Total '(5)
164										
165	**Wind Curtailment**		**$ 127,718**	**$ 54,571**	**$ 752,132**	**$ 337,570**	**$ 544,851**	**$ (417,133)**	**-77%**	(6)
166										
167	**Asset Based Sales**		**$ (8,444,419)**	**$ (12,047,753)**	**$ (17,662,312)**	**$ (15,589,196)**				Credit to MN FCA Calculation - Subtracted from Total
168		Fuel Costs	$ (3,578,779)	$ (8,985,597)	$ (12,303,307)	$ (11,469,286)	**$ (11,886,297)**	**$ 8,307,517**	**-70%**	(7)
169		Asset Based Margins	$ (4,865,639)	$ (3,062,156)	$ (5,359,005)	$ (4,119,910)	**$ (4,739,457)**	**$ (126,182)**	**3%**	(8)
170										
171	**Hoot Lake Solar Generation Credit**		**$ (3,736,608)**	**$ (1,811,225)**						**Otter Tail proposed credit methodology in 2023 Forecast Docket**
172										
173	**Steam Plant Reagents**		**$ 3,098,880**	**$ 2,164,427**	**$ 1,361,327**					**Reagents not applicable to MN EAR recovery until July 2022**
174										
175	**Steam and Water Sales: Net Margin**		**$ (1,264,592)**	**$ (808,406)**	**$ (587,137)**					**Steam and Water Sales not applicable to MN EAR recovery until July 202**
176										
177	**Planning Resource Auction Revenues**			**$ (4,185,367)**	**$ (5,347,776)**					
178										
177	**Total System Costs**		**$ 140,775,339**	**$ 120,763,238**	**$ 144,347,469**	**$ 103,470,069**	**$ 123,908,769**	**$ 16,866,570**	**14%**	Tribal (WAPA) excluded from Total; Asset Based Sales subtracted from Total (9)

Line			2025fx	2023	2022	2021	3-YR Average
178	**System Sales - kWh**		**5,885,377,876**	**5,865,294,464**	**5,575,424,134**	**4,772,030,634**	**5,173,727,384**

-

(1) Increased forecasted dispatch of Coal and Natural Gas units in lieu of market purchases. When Otter Tail-owned units are more economical than purchasing energy from the market they are used accordingly.

(2) Due to the scheduled completion of transmission outages and upgrades within the Otter Tail service territory, Otter Tail expects congestion costs and FTR revenues to decrease in 2024. This reduction results in a forecasted elimination of the MISO wholesale energy market credit and a return to a more typical expectation of a MISO wholesale energy market charge. See Page 19 of Otter Tail's May 1, 2023 Initial Filing for further explanation.

(3) Otter Tail has experienced increasing SPP revenue amounts in recent years and expects that to continue into 2025.

(4) Otter Tail has experienced overall increasing MISO ASM revenue amounts in recent years and expects that to continue into 2025.

(5) Increased forecasted energy market prices compared to recent years.

(6) Lower forecasted MWh compared to recent years resulted in decreased forecasted costs **[PROTECTED DATA BEGINS...** **...PROTECTED DATA ENDS]**

(7) Forecasted OTP-owned resources fuel cost per MWh is higher than recent years. Forecasted MWh is higher than recent years.

(8) Decreasing forecasted energy market prices compared to recent years leads to decreasing margins from asset-based sales with the inverse being the case for increasing forecasted energy market prices.

(9) The combined effects of Footnotes 1 through 8, plus increased load on Otter Tail's system results in the increase.

Table B - MWh

Line			2025fx	2023	2022	2021	3-YR Average	Notes
	Plant Generation		**[PROTECTED DATA BEGINS...**					
1		Big Stone						
2		Coyote						
3		Hoot Lake #2						2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
4		Hoot Lake #3						2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
5							**...PROTECTED DATA ENDS]**	
6		**Total Coal**	**1,986,376**	**1,759,136**	**1,819,294**	**1,877,694**	**1,818,708**	
7			**[PROTECTED DATA BEGINS...**					
8		Langdon Wind						
9		Ashtabula Wind						
10		Ashtabula III						Forecasted to be owned by OTP in January 2023. Shows in Purchased Power sectio
11		Luverne Wind						
12		Merricourt						Merricourt went into service in Q4 2020
13							**...PROTECTED DATA ENDS]**	
14		**Total Wind**	**1,281,553**	**1,145,385**	**1,034,186**	**959,910**	**1,046,494**	
15								
16		**Total Hydro**	**20,000**	**8,846**	**12,850**	**14,299**	**11,998**	
17			**[PROTECTED DATA BEGINS...**					
18		Jamestown 1						
19		Jamestown 2						
20		Lake Preston						
21							**...PROTECTED DATA ENDS]**	
22		**Total Oil - Peaking Units**	**874**	**946**	**1,050**	**2,889**	**1,628**	
23			**[PROTECTED DATA BEGINS...**					
24		Natural gas - Solway						
25		Natural gas - Astoria						Astoria Station went into service in 2021
26		**Total Natural Gas**						Total Natural Gas needs to be protected because Solway is the only plant for
27							**...PROTECTED DATA ENDS]**	
28			**[PROTECTED DATA BEGINS...**					
29		Solar - Hoot Lake Solar						Forecasted to be in service in 2023
30		Solar - Blue Jay						
31		Solar - Blue Heron						
32							**...PROTECTED DATA ENDS]**	
33		**Total Solar**	**86,717**	**34,982**	**96**	**96**	**11,725**	
34								
35		**Total OTP-Owned**	**3,895,315**	**3,519,911**	**3,128,313**	**3,217,521**	**3,288,582**	
36								
37	**Wholesale Market Charges**							
38		**MISO Wholesale Market Charges**						
39	555.02	DA Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
40	555.04	DA FBT Loss Amount	N/A	N/A	N/A	N/A	N/A	
41	555.09	DA Non-asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
42	555.19	RT Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
43	555.24	RT Distribution of Losses Amount	N/A	N/A	N/A	N/A	N/A	
44	555.21	RT FBT Loss Amount	N/A	N/A	N/A	N/A	N/A	
45		DA Loss Amount	N/A	N/A	N/A	N/A	N/A	
46		RT Loss Amount	N/A	N/A	N/A	N/A	N/A	
47	555.26	RT Non-Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
48	555.08	DA Losses Rebate on Option B GFA	N/A	N/A	N/A	N/A	N/A	
49	555.12	DA Virtual Energy Amount	N/A	N/A	N/A	N/A	N/A	
50	555.32	RT Virtual Energy Amount	N/A	N/A	N/A	N/A	N/A	
51	555.01	DA Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
52	555.18	RT Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
53	555.13	FTR Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
54	555.03	DA FBT Congestion Amount	N/A	N/A	N/A	N/A	N/A	
55		DA Congestion	N/A	N/A	N/A	N/A	N/A	
56	555.2	RT FBT Congestion Amount	N/A	N/A	N/A	N/A	N/A	
57		RT Congestion	N/A	N/A	N/A	N/A	N/A	
58	555.14	FTR Hourly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
59	555.15	FTR Monthly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
60	555.17	FTR Yearly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
61	555.35	FTR Monthly Transaction Amount	N/A	N/A	N/A	N/A	N/A	
62	555.36	FTR Full Funding Guarantee Amount	N/A	N/A	N/A	N/A	N/A	
63	555.37	FTR Guarantee Uplift Amount	N/A	N/A	N/A	N/A	N/A	
64	555.39	FTR Auction Revenue Rights Transaction Amount	N/A	N/A	N/A	N/A	N/A	
65	555.38	FTR Annual Transaction Amount	N/A	N/A	N/A	N/A	N/A	
66	555.40	FTR Auction Revenue Rights Infeasible Uplift Amount	N/A	N/A	N/A	N/A	N/A	
67	555.41	FTR Auction Revenue Rights Stage 2 Distribution Amount	N/A	N/A	N/A	N/A	N/A	
68	555.07	DA Congestion Rebate on Option B GFA	N/A	N/A	N/A	N/A	N/A	
69	555.1	DA Revenue Sufficiency Guarantee Distribution Amount	N/A	N/A	N/A	N/A	N/A	
70	555.11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	N/A	N/A	N/A	N/A	N/A	
71	555.29	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	N/A	N/A	N/A	N/A	N/A	
72	555.3	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	N/A	N/A	N/A	N/A	N/A	
73	555.42	RT Price Volatility Make Whole Payment	N/A	N/A	N/A	N/A	N/A	
74	555.28	RT Revenue Neutrality Uplift Amount	N/A	N/A	N/A	N/A	N/A	
75	555.25	RT Misc Amount	N/A	N/A	N/A	N/A	N/A	
76	555.27	RT Net Inadvertent Amount	N/A	N/A	N/A	N/A	N/A	
77	555.31	RT Uninstructed Deviation Amount	N/A	N/A	N/A	N/A	N/A	
78	555.59	RT Demand Response Allocation Uplift Amount	N/A	N/A	N/A	N/A	N/A	
79	555.63	DA Ramp Product	N/A	N/A	N/A	N/A	N/A	
80	555.64	RT Ramp Product	N/A	N/A	N/A	N/A	N/A	
81	555.65	RT Schedule 49 Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
82	555.55	RT ASM Non-Excessive Energy Amount***	N/A	N/A	N/A	N/A	N/A	
83	555.56	RT ASM Excessive Energy Amount***	N/A	N/A	N/A	N/A	N/A	
84	555.05	DA Congestion Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
85	555.06	DA Losses Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
86	555.22	RT Congestion Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
87	555.23	RT Loss Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
88		Net Congestion and Losses Adjustment & No DA Generation Schedule	N/A	N/A	N/A	N/A	N/A	
89		Settlement with another utility in Otter Tail's LBA	N/A	N/A	N/A	N/A	N/A	
90		**Total MISO Wholesale Market Charges**	-	-	-	-	-	
91								
92		**SPP Wholesale Market Charges**						
93	555.19	DA Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
94	555.03	DA Non-asset Energy Amount	N/A	N/A	N/A	N/A	N/A	
95	555.09	RT Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
96	555	RT Non-Asset Energy Amount	N/A	N/A	N/A	N/A	N/A	
97	555.02	DA Make-Whole-Payment Distribution Amount	N/A	N/A	N/A	N/A	N/A	
98	555.1	RT Make-Whole-Payment Distribution Amount	N/A	N/A	N/A	N/A	N/A	
99	555.18	RT Revenue Sufficiency Guarantee Distribution Amount	N/A	N/A	N/A	N/A	N/A	
100	555.15	RT Revenue Neutrality Uplift Distribution Amount	N/A	N/A	N/A	N/A	N/A	
101	555.04	DA Regulation-Down Distribution Amount	N/A	N/A	N/A	N/A	N/A	
102	555.05	DA Regulation-Up Distribution Amount	N/A	N/A	N/A	N/A	N/A	
103	555.06	DA Spinning Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
104	555.07	DA Supplemental Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
105	555.08	RT Contingency Reserve Deployment Failure Amount	N/A	N/A	N/A	N/A	N/A	
106	555.11	RT Over-Collected Losses Distribution Amount	N/A	N/A	N/A	N/A	N/A	
107	555.12	RT Regulation-Down Distribution Amount	N/A	N/A	N/A	N/A	N/A	
108	555.13	RT Regulation Non-Performance Distribution Amount	N/A	N/A	N/A	N/A	N/A	
109	555.14	RT Regulation-Up Distribution Amount	N/A	N/A	N/A	N/A	N/A	
110	555.16	RT Spinning Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
111	555.17	RT Supplemental Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
112	555.2	RT Pseudo Tie Congestion Amount	N/A	N/A	N/A	N/A	N/A	
113	555.21	RT Pseudo Tie Loss Amount	N/A	N/A	N/A	N/A	N/A	
114	555.23	Miscellaneous Amount	N/A	N/A	N/A	N/A	N/A	
115	555.26	ARR Closeout Yearly Amount	N/A	N/A	N/A	N/A	N/A	
116	555.28	RT Demand Reduction Distribution Amount	N/A	N/A	N/A	N/A	N/A	
117	555.29	RT Schedule 1A3 Amount	N/A	N/A	N/A	N/A	N/A	
118	555.3	RT Schedule 1A4 Amount	N/A	N/A	N/A	N/A	N/A	
119	555.01	DA GFA Carve Out Distribution Deployment Daily Amount	N/A	N/A	N/A	N/A	N/A	
120	555.22	DA GFA Carve Out Distribution Deployment Monthly Amount	N/A	N/A	N/A	N/A	N/A	
121	555.27	DA GFA Carve Out Distribution Deployment Yearly Amount	N/A	N/A	N/A	N/A	N/A	
122		**Total SPP Wholesale Market Charges**	-	-	-	-	-	
123								
124		**MISO ASM**						
125		Day Ahead Regulation Amount	N/A	N/A	N/A	N/A	N/A	
126		Real Time Regulation Amount	N/A	N/A	N/A	N/A	N/A	
127		Regulation Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
128		Day Ahead Short-Term Reserve Amount	N/A	N/A	N/A	N/A	N/A	
129		Real Time Short-Term Reserve Amount	N/A	N/A	N/A	N/A	N/A	
130		Real Time Short-Term Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
131		Real Time Short-Term Reserve Deployent Failure Charge Amount	N/A	N/A	N/A	N/A	N/A	
132		Day Ahead Spinning Reserve Amount	N/A	N/A	N/A	N/A	N/A	
133		Real Time Spinning Reserve Amount	N/A	N/A	N/A	N/A	N/A	
134		Spinning Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
135		Day Ahead Supplemental Reserve Amount	N/A	N/A	N/A	N/A	N/A	
136		Real Time Supplemental Reserve Amount	N/A	N/A	N/A	N/A	N/A	
137		Supplemental Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
138		Contingency Reserve Deployment Failure Charge Amount	N/A	N/A	N/A	N/A	N/A	
139		Real Time Excessive Deficient Energy Deployment Charge Amount	N/A	N/A	N/A	N/A	N/A	
140		Net Regulation Adjustment Amount	N/A	N/A	N/A	N/A	N/A	
141		**Total MISO ASM**	-	-	-	-	-	
142								
143		**Total Wholesale Market Charges**	-	-	-	-	-	
144								
145								
146	**Purchased Power**							
147			**[PROTECTED DATA BEGINS...**					
148		Edgeley PPA						
149		Langdon PPA						
150		Ashtabula III PPA						Forecasted to be OTP-Owned in 2023
151		Tribal (WAPA)						Not Applicable to EAR - Excluded from Total
152		WAPA Energy Imbalance						Load balancing amounts between OTP and WAPA
153		Shared Loads						
154		Small Co-gen						
155		Bilateral purchases						
156		Market Purchases						MISO and SPP Energy
157							**...PROTECTED DATA ENDS]**	
158		**Total Purchases**	**2,355,460**	**2,693,048**	**2,921,422**	**2,108,120**	**2,574,197**	Tribal (WAPA) excluded from Total
159								
160	**Wind Curtailment**		**3,256**	**1,062**	**22,625**	**10,615**	**11,434**	
161								
162	**Asset Based Sales**		**133,231**	**348,728**	**263,805**	**416,066**	**342,866**	Credit to MN FCA Calculation - Subtracted from Total
163		Fuel Costs						Based Sales
164		Asset Based Margins						Based Sales
165								
166	**Hoot Lake Solar Generation Credit**		N/A	N/A	N/A	N/A	N/A	
167								
168	**Steam Plant Reagents**		N/A	N/A	N/A	N/A	N/A	
169								
170	**Steam and Water Sales: Net Margin**		N/A	N/A	N/A	N/A	N/A	
171								
172	**Total System - Plant Level**		**6,120,800**	**5,865,294**	**5,808,556**	**4,920,191**	**5,531,347**	Tribal (WAPA) excluded from Total; Asset Based Sales subtracted from Total

Table C - $ per MWh

Line			2025fx	2023	2022	2021	3-YR Average	Notes
Line	**Plant Generation**		**[PROTECTED DATA BEGINS...**					
1		Big Stone						2023 Big Stone Plant coal pricing change is described on page 28 of our Initial Filing.
2		Coyote						
3		Hoot Lake #2						2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
4		Hoot Lake #3						2018 to 2020 Actuals include Hoot Lake #2 and #3 combined. Retired in 2021
5						**...PROTECTED DATA ENDS]**		
6		**Total Coal**	**$ 25.85**	**$ 25.22**	**$ 23.03**	**$ 1.71**	**$ 23.76**	
7			**[PROTECTED DATA BEGINS...**					
8		Langdon Wind						
9		Ashtabula Wind						
10		Ashtabula III						Forecasted to be owned by OTP in January 2023
11		Luverne Wind						
12		Merricourt						Merricourt went into service in Q4 2020
13						**...PROTECTED DATA ENDS]**		
14		**Total Wind**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
15								
16		**Total Hydro**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
17			**[PROTECTED DATA BEGINS...**					
18		Jamestown 1						
19		Jamestown 2						
20		Lake Preston						
21						**...PROTECTED DATA ENDS]**		
22		**Total Oil - Peaking Units**	**$ 281.92**	**$ 468.69**	**$ 456.58**	**$ 301.92**	**$ 367.45**	
23			**[PROTECTED DATA BEGINS...**					
24		Natural gas - Solway						
25		Natural gas - Astoria						Astoria Station went into service in 2021
26		**Total Natural Gas**						Total Natural Gas needs to be protected because Solway is the only plant for 2018-2020
27						**...PROTECTED DATA ENDS]**		
28			**[PROTECTED DATA BEGINS...**					
29		Solar - Hoot Lake Solar						Forecasted to be in service in 2023
30		Solar - Blue Jay						
31		Solar - Blue Heron						
32						**...PROTECTED DATA ENDS]**		
33		**Total Solar**	0	0	0	N/A	$ -	
34								
35		**Total OTP-Owned**	**$ 17.44**	**$ 17.04**	**$ 20.76**	**$ 18.44**	**$ 18.67**	
36								
37	**Wholesale Market Charges**							
38		**MISO Wholesale Market Charges**						
39	555.02	DA Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
40	555.04	DA FBT Loss Amount	N/A	N/A	N/A	N/A	N/A	
41	555.09	DA Non-asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
42	555.19	RT Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
43	555.24	RT Distribution of Losses Amount	N/A	N/A	N/A	N/A	N/A	
44	555.21	RT FBT Loss Amount	N/A	N/A	N/A	N/A	N/A	
45		DA Loss Amount	N/A	N/A	N/A	N/A	N/A	
46		RT Loss Amount	N/A	N/A	N/A	N/A	N/A	
47	555.26	RT Non-Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
48	555.08	DA Losses Rebate on Option B GFA	N/A	N/A	N/A	N/A	N/A	
49	555.12	DA Virtual Energy Amount	N/A	N/A	N/A	N/A	N/A	
50	555.32	RT Virtual Energy Amount	N/A	N/A	N/A	N/A	N/A	
51	555.01	DA Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
52	555.18	RT Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
53	555.13	FTR Mkt Admin Amount	N/A	N/A	N/A	N/A	N/A	
54	555.03	DA FBT Congestion Amount	N/A	N/A	N/A	N/A	N/A	
55		DA Congestion	N/A	N/A	N/A	N/A	N/A	
56	555.2	RT FBT Congestion Amount	N/A	N/A	N/A	N/A	N/A	
57		RT Congestion	N/A	N/A	N/A	N/A	N/A	
58	555.14	FTR Hourly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
59	555.15	FTR Monthly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
60	555.17	FTR Yearly Allocation Amount	N/A	N/A	N/A	N/A	N/A	
61	555.35	FTR Monthly Transaction Amount	N/A	N/A	N/A	N/A	N/A	
62	555.36	FTR Full Funding Guarantee Amount	N/A	N/A	N/A	N/A	N/A	
63	555.37	FTR Guarantee Uplift Amount	N/A	N/A	N/A	N/A	N/A	
64	555.39	FTR Auction Revenue Rights Transaction Amount	N/A	N/A	N/A	N/A	N/A	
65	555.38	FTR Annual Transaction Amount	N/A	N/A	N/A	N/A	N/A	
66	555.40	FTR Auction Revenue Rights Infeasible Uplift Amount	N/A	N/A	N/A	N/A	N/A	
67	555.41	FTR Auction Revenue Rights Stage 2 Distribution Amount	N/A	N/A	N/A	N/A	N/A	
68	555.07	DA Congestion Rebate on Option B GFA	N/A	N/A	N/A	N/A	N/A	
69	555.1	DA Revenue Sufficiency Guarantee Distribution Amount	N/A	N/A	N/A	N/A	N/A	
70	555.11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	N/A	N/A	N/A	N/A	N/A	
71	555.29	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	N/A	N/A	N/A	N/A	N/A	
72	555.3	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	N/A	N/A	N/A	N/A	N/A	
73	555.42	RT Price Volatility Make Whole Payment	N/A	N/A	N/A	N/A	N/A	
74	555.28	RT Revenue Neutrality Uplift Amount	N/A	N/A	N/A	N/A	N/A	
75	555.25	RT Misc Amount	N/A	N/A	N/A	N/A	N/A	
76	555.27	RT Net Inadvertent Amount	N/A	N/A	N/A	N/A	N/A	
77	555.31	RT Uninstructed Deviation Amount	N/A	N/A	N/A	N/A	N/A	
78	555.59	RT Demand Response Allocation Uplift Amount	N/A	N/A	N/A	N/A	N/A	
79	555.63	DA Ramp Product	N/A	N/A	N/A	N/A	N/A	
80	555.64	RT Ramp Product	N/A	N/A	N/A	N/A	N/A	
81	555.65	RT Schedule 49 Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
82	555.55	RT ASM Non-Excessive Energy Amount***	N/A	N/A	N/A	N/A	N/A	
83	555.56	RT ASM Excessive Energy Amount***	N/A	N/A	N/A	N/A	N/A	
84	555.05	DA Congestion Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
85	555.06	DA Losses Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
86	555.22	RT Congestion Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
87	555.23	RT Loss Rebate on COGA	N/A	N/A	N/A	N/A	N/A	
88		Net Congestion and Losses Adjustment & No DA Generation Schedule	N/A	N/A	N/A	N/A	N/A	
89		Settlement with another utility in Otter Tail's LBA	N/A	N/A	N/A	N/A	N/A	
90		**Total MISO Wholesale Market Charges**						
91								
92		**SPP Wholesale Market Charges**						
93	555.19	DA Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
94	555.03	DA Non-asset Energy Amount	N/A	N/A	N/A	N/A	N/A	
95	555.09	RT Asset Energy Amount***	N/A	N/A	N/A	N/A	N/A	
96	555	RT Non-Asset Energy Amount	N/A	N/A	N/A	N/A	N/A	
97	555.02	DA Make-Whole-Payment Distribution Amount	N/A	N/A	N/A	N/A	N/A	
98	555.1	RT Make-Whole-Payment Distribution Amount	N/A	N/A	N/A	N/A	N/A	
99	555.18	RT Revenue Sufficiency Guarantee Distribution Amount	N/A	N/A	N/A	N/A	N/A	
100	555.15	RT Revenue Neutrality Uplift Distribution Amount	N/A	N/A	N/A	N/A	N/A	
101	555.04	DA Regulation-Down Distribution Amount	N/A	N/A	N/A	N/A	N/A	
102	555.05	DA Regulation-Up Distribution Amount	N/A	N/A	N/A	N/A	N/A	
103	555.06	DA Spinning Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
104	555.07	DA Supplemental Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
105	555.08	RT Contingency Reserve Deployment Failure Amount	N/A	N/A	N/A	N/A	N/A	
106	555.11	RT Over-Collected Losses Distribution Amount	N/A	N/A	N/A	N/A	N/A	
107	555.12	RT Regulation-Down Distribution Amount	N/A	N/A	N/A	N/A	N/A	
108	555.13	RT Regulation Non-Performance Distribution Amount	N/A	N/A	N/A	N/A	N/A	
109	555.14	RT Regulation-Up Distribution Amount	N/A	N/A	N/A	N/A	N/A	
110	555.16	RT Spinning Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
111	555.17	RT Supplemental Reserve Distribution Amount	N/A	N/A	N/A	N/A	N/A	
112	555.2	RT Pseudo Tie Congestion Amount	N/A	N/A	N/A	N/A	N/A	
113	555.21	RT Pseudo Tie Loss Amount	N/A	N/A	N/A	N/A	N/A	
114	555.23	Miscellaneous Amount	N/A	N/A	N/A	N/A	N/A	
115	555.26	ARR Closeout Yearly Amount	N/A	N/A	N/A	N/A	N/A	
116	555.28	RT Demand Reduction Distribution Amount	N/A	N/A	N/A	N/A	N/A	
117	555.29	RT Schedule 1A3 Amount	N/A	N/A	N/A	N/A	N/A	
118	555.3	RT Schedule 1A4 Amount	N/A	N/A	N/A	N/A	N/A	
119	555.01	DA GFA Carve Out Distribution Deployment Daily Amount	N/A	N/A	N/A	N/A	N/A	
120	555.22	DA GFA Carve Out Distribution Deployment Monthly Amount	N/A	N/A	N/A	N/A	N/A	
121	555.27	DA GFA Carve Out Distribution Deployment Yearly Amount	N/A	N/A	N/A	N/A	N/A	
122		**Total SPP Wholesale Market Charges**						
123								
124		**MISO ASM**						
125		Day Ahead Regulation Amount	N/A	N/A	N/A	N/A	N/A	
126		Real Time Regulation Amount	N/A	N/A	N/A	N/A	N/A	
127		Regulation Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
128		Day Ahead Short-Term Reserve Amount	N/A	N/A	N/A	N/A	N/A	
129		Real Time Short-Term Reserve Amount	N/A	N/A	N/A	N/A	N/A	
130		Real Time Short-Term Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
131		Real Time Short-Term Reserve Deployent Failure Charge Amount	N/A	N/A	N/A	N/A	N/A	
132		Day Ahead Spinning Reserve Amount	N/A	N/A	N/A	N/A	N/A	
133		Real Time Spinning Reserve Amount	N/A	N/A	N/A	N/A	N/A	
134		Spinning Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
135		Day Ahead Supplemental Reserve Amount	N/A	N/A	N/A	N/A	N/A	
136		Real Time Supplemental Reserve Amount	N/A	N/A	N/A	N/A	N/A	
137		Supplemental Reserve Cost Distribution Amount	N/A	N/A	N/A	N/A	N/A	
138		Contingency Reserve Deployment Failure Charge Amount	N/A	N/A	N/A	N/A	N/A	
139		Real Time Excessive Deficient Energy Deployment Charge Amount	N/A	N/A	N/A	N/A	N/A	
140		Net Regulation Adjustment Amount	N/A	N/A	N/A	N/A	N/A	
141		**Total MISO ASM**						
142								
143		**Total Wholesale Market Charges**						
144								
145								
146	**Purchased Power**							
147			**[PROTECTED DATA BEGINS...**					
148		Edgeley PPA						
149		Langdon PPA						
150		Ashtabula III PPA						Forecasted to be OTP-Owned in 2023
151		Tribal (WAPA)						Not Applicable to EAR - Excluded from Total
152		WAPA Energy Imbalance						Load balancing amounts between OTP and WAPA
153		Shared Loads						
154		Small Co-gen						
155		Bilateral purchases						
156		Market Purchases						MISO and SPP Energy
157						**...PROTECTED DATA ENDS]**		
158		**Total Purchases**	**$ 40.81**	**$ 34.34**	**$ 40.77**	**$ 33.01**	**$ 36.41**	Tribal (WAPA) excluded from Total
159								
160	**Wind Curtailment**		**$ 39.22**	**$ 51.41**	**$ 33.24**	**$ 31.80**	**$ 33.36**	
161								
162	**Asset Based Sales**		**$ (63.38)**	**$ (34.55)**	**$ (66.95)**	**$ (37.47)**	**$ (44.04)**	
163		Fuel Costs	N/A	N/A	N/A	N/A		Fuel Cost MWh and Margin MWH are not separated - Need to compare total Asset Based Sales
164		Asset Based Margins	N/A	N/A	N/A	N/A		Fuel Cost MWh and Margin MWH are not separated - Need to compare total Asset Based Sales
165								
166	**Hoot Lake Solar Generation Credit**		**N/A**	**N/A**	**N/A**	**N/A**		
167								
168	**Steam Plant Reagents**		**N/A**	**N/A**	**N/A**	**N/A**		
169								
170	**Steam and Water Sales: Net Margin**		**N/A**	**N/A**	**N/A**	**N/A**		
171								
172	**Total System - Plant Level**		**$ 23.00**	**$ 20.59**	**$ 24.85**	**$ 21.03**	**$ 22.21**	Tribal (WAPA) excluded from Total; Asset Based Sales subtracted from Total

[PROTECTED DATA BEGINS…

Docket No. E017/AA-24-
Attachment 13
is CONFIDENTIAL
in its Entirety

…PROTECTED DATA ENDS]

Bilateral (Forward) Energy Purchases **[PROTECTED DATA BEGINS...**	
	...PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…

Docket No. E017/AA-24-
Attachments 14.1 thru 14.6
are CONFIDENTIAL
in their Entirety

…PROTECTED DATA ENDS]

CERTIFICATE OF SERVICE

RE: In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01
Docket No. E017/AA-24-

I, Valerie Moxness, hereby certify that I have this day served a copy of the following, or a summary thereof, on Will Seuffert and Sharon Ferguson by e-filing, and to all other persons on the attached service list by electronic service or by First Class Mail.

Otter Tail Power Company
Initial Filing

Dated this 1st day of May 2024.

/s/ Valerie Moxness
Valerie Moxness
Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8346

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company	PO Box 496 Fergus Falls, MN 56538-0496	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.	11 East Superior St Ste 125 Duluth, MN 55802	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Regulatory	regulatory_filing_coordinators@otpco.com	Otter Tail Power Company	215 S. Cascade Street Fergus Falls, MN 56537	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Cary	Stephenson	cStephenson@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	GEN_SL_Otter Tail Power Company_Otter Tail Power Company_2025 MN FCA Forecast