



AN ALLETE COMPANY

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March 3, 2026

VIA E-FILING

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

Re: In the Matter of Minnesota Power's Petition for
Approval of the Annual Forecasted Rates for its Rider
for Fuel and Purchased Energy Charge
Docket No. E015/AA-24-64
Annual True-up Report

Dear Ms. Bergman:

Minnesota Power respectfully submits to the Minnesota Public Utilities Commission its Annual Automatic Adjustment True-up Report of Forecasted Fuel and Purchased Energy rates for the calendar year 2025 pursuant to the decisions rendered by the Commission in Docket No. E999/CI-03-802 and where applicable, in compliance with Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges.

Please contact me at (218) 591-4870 or avang@mnpower.com if you have any questions regarding this compliance filing.

Yours truly,

A handwritten signature in black ink, appearing to read 'Ana Vang'.

Ana Vang
Regulatory Compliance Specialist, Senior

AV:sr
Attach.

**STATEMENT REGARDING JUSTIFICATION FOR EXCISING
TRADE SECRET INFORMATION**

Minnesota Power has excised material from the Annual Automatic Adjustment of Charges True-Up Report ("Report") because the format of the Report requires Minnesota Power to compile and provide information regarding its methods, techniques and process for obtaining and managing fuel supply resources for its generating facilities, including fuel supply, contract terms and conditions, as well as fuel cost projections. This is highly confidential information: Minnesota Power's competitors, as well as its potential suppliers, would gain a commercial advantage over Minnesota Power if this information was publicly available. As a result of public availability, Minnesota Power and its customers would suffer from corruption of Minnesota Power's negotiating position. Minnesota Power follows strict internal procedures to maintain the secrecy of this information in order to capitalize on economic value of the information to Minnesota Power.

Minnesota Power believes that this statement justifies why the information excised from the attached Report should remain a trade secret under Minn. Stat. §13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

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

In the Matter of Minnesota Power’s Petition for Approval
of the Annual Automatic Adjustment Charges for the
Period of January 2025 through December 2025

Docket No. E015/AA-24-64
**MINNESOTA POWER’S
ANNUAL TRUE UP REPORT AND
RATE ADJUSTMENT PROPOSAL**

I. INTRODUCTION

Minnesota Power (or the “Company”) filed its Annual Forecasted Fuel and Purchased Energy rates for calendar year 2025 on May 1, 2024, in the above referenced docket. On November 12, 2024, the Minnesota Public Utilities Commission (“Commission”) issued its order, allowing the Company to implement its calendar year 2025 Fuel and Purchased Energy Rider (“FPE Rider” or Fuel Adjustment Clause “FAC”) forecast rates, based on forecasted sales of 8,997,900 MWh and forecasted fuel costs of \$266.4 million. On January 30, 2025, the Company filed a rate adjustment in the above referenced docket to implement adjusted monthly fuel cost charges beginning March 1, 2025, as part of the Order and Implementation of Minnesota Power’s rate case compliance filing and interim rate refund plan Accepting the Settlement Agreement in the Company’s 2023 Rate Case.¹ The total 2025 FAC Forecast was \$271.6 million after those updates in early 2025. The Company’s actual 2025 sales were 8,192,436 MWh and actual fuel costs were \$252.5 million. Actual fuel costs and sales were lower in 2025 compared to forecast, which resulted in a higher \$/MWh based on actuals. Please refer to “Table 1: Fuel Cost Summary” for a breakdown of forecast and actual fuel costs. The higher-than-expected \$/MWh fuel costs resulted in a total under collected amount of \$3.9 million in fuel costs for 2025.

On July 1, 2024, the Commission issued its order In the Matter of Minnesota Power’s Petition for Approval of Annual Automatic Adjustment Charges for the Period of January 2023 through December 2023 in Docket No. E015/AA-22-216. Order Points 2 and 3 of that docket state:

¹ In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in the State of Minnesota. Docket No. E-015/GR-23-155. December 20, 2024 Compliance Filing.

Order Point 2

“Authorized Minnesota Power to refund its 2023 over-collection of \$11,018,119.”

Order Point 3

“Allowed Minnesota Power to refund the 2023 over-collection over a 12-month period starting the 1st day of September after the Commission issues its written order.”

Minnesota Power implemented the 2023 refund from September 1, 2024, through August 31, 2025. At the completion of the 12-month refund period, Minnesota Power under refunded \$504,765, which is being included in the 2025 fuel clause adjustment (“FCA”) true-up filing. See Attachment 2 – Automatic Retail Fuel Adjustment Charges TS for support.

Minnesota Power proposes a 2025 FAC True-up amount of approximately \$3.5 million, to be collected over a 12-month period beginning September 1, 2026, subject to Commission approval

II. HISTORY AND COMPLIANCE

The Commission’s June 2019 Order in Docket No. E999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, approved a variance to Minn. Rules 7825.2800 through 7825.2840 and reporting requirements for the annual forecast and true-up filings. Order Point 1 states:

“The Commission approves variances to Minn. R. 7825.2800, .2810, .2820, .2830, and .2840 in accordance with the language stated above in Section II.”

This filing contains information provided in compliance with the following:

- Order Point 7 of the June 2019 Order in Docket No. E999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments (see section A. Self-Commitment and Self-Scheduling Analysis);
- Order Point 9 of the November 13, 2019 in Docket No. E999/AA-18-373, In the Matter of the Review of the 2017-2018 Annual Automatic Adjustment Report for

All Electric Utilities (see Section A. Self-Commitment and Self-Scheduling Analysis);

- Order Points 2A, 2B, 3A, and 3B of the Commission’s March 12, 2024 Order in Docket No. E-999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments (see section B. Lessons Learned Report);
- Order Point 1 of the Commission’s June 2019 Order in Docket No. E999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, regarding Minn. Rules 7825.2800 through 7825.2840 (see section C. Rule 7825.2800 Annual Reports: Policies and Action through section G Rule 7825.2840 Annual Notice of Reports Availability);

A. Self-Commitment and Self-Scheduling Analysis

The Commission’s June 2019 Order in Docket No. E999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, approved a variance to Minn. Rules 7825.2800 through 7825.2840 and reporting requirements for the annual forecast and true-up filings. Specifically, in regard to Self-Commitment and Self-Scheduling analysis, Order Point 7 state the following:

“The Commission adopts the reporting changes outlined in Attachments 1, 2, and 3 of the joint comments with the following reporting requirement added to the annual true-up filing: each Electric Utility shall provide a complete analysis and discussion of the consequences of self-commitment and self-scheduling of their generators, including the annual difference between production costs and corresponding prevailing market prices.”

As part of the November 13, 2019 Order in Docket No. E999/AA-18-373, In the Matter of the Review of the 2017-2018 Annual Automatic Adjustment Report for All Electric Utilities, Order Point 9 states:

“The Commission will open an investigation in a separate docket and require Minnesota Power, Otter Tail, and Xcel to report their future self-commitment and self-scheduling analyses using a consistent methodology by including fuel cost and variable O&M costs, matching the offer curve submitted to MISO energy markets.”

Minnesota Power's annual compliance report regarding self-commitment and self-scheduling of large base load generators was filed on March 2, 2026 in Docket No. E999/CI-19-704, In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities. In a December 29, 2025 filing in that docket, the Minnesota Department of Commerce, Division of Energy Resources, Minnesota Power, Otter Tail Power Company, and Xcel Energy proposed to include the entirety of the Annual Compliance Filing within each utility's Annual Fuel Forecast True-Up Report rather than filing the annual report as a stand-alone.

B. Lessons Learned Report

On August 15, 2023, Minnesota Power, Xcel Energy, and Otter Tail Power Company submitted reports in Docket No. E-999/CI-03-802, In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, on their experience implementing the Commission's new policy reducing the frequency with which utilities adjust their electric rates to reflect changes in energy-related costs. On March 12, 2024, the Commission ordered the following:

"2. In their future Fuel Clause Adjustment filings, the three utilities shall incorporate —

A. Answers to the recurring information requests, including the most recent three-year average of actual annual data compared to 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.

3. The Commission also approves Minnesota Power's proposed changes to —

A. the attachment addressing costs related to the Midcontinent Independent System Operator, Inc., in the annual FCA forecast filing; and

B. the attachment to its annual FCA true-up filing addressing charges related to MISO's ancillary service market."

For Order Point 2A, the comparison of the most recent three-year average of actual annual data compared to forecast is supplied in the Company's annual forecast filing (YR-64 on a forward looking basis). At this time, the Company does not make winter energy specific purchases, so Order Point 2B is inapplicable to this filing. The changes to the MISO Costs and ASM Charges Attachments have been incorporated into this filing.

C. Rule 7825.2800 Annual Reports: Policies and Action

This section includes information regarding Minnesota Power's fuel and energy source procurement and energy dispatching policies.

Fuel Source Procurement Policies

Fuel Cost Minimization Activities

Minnesota Power's fuel procurement practices are aimed at strategically minimizing customers' current energy costs while complying with current environmental regulations and, simultaneously, taking action to assure cost-effective compliance with future environmental requirements. Attaining these objectives requires that purchases and sales of energy, applicable coal and rail contract provisions, current and projected emissions, mine plans of suppliers, requirements of customers, fuel delivery schedules, fuel inventory, fuel and rail costs, etc., be continuously evaluated. Balancing these parameters requires superimposing long- and short-term planning objectives on near-term operations.

In addition, Minnesota Power uses a multi-discipline fuels procurement and strategy team to achieve fuel cost minimization and environmental compliance objectives. The team meets regularly to coordinate all activities related to fuel procurement. Objectives include:

- Implement strategies for short- and long-term fuel procurement which provide a high-quality, flexible, and reliable fuel supply to Minnesota Power facilities to achieve the lowest attainable electric rates.

- Optimize fuel costs and quality through developing, implementing and managing the short-term strategy for fuel scheduling and deliveries within operating and contract parameters.
- Environmental compliance planning efforts focus on the formulation, implementation and minimization of short- and long-term corporate strategies for fuel quality issues and the impact of fuel on plant performance and compliance with existing and emerging environmental regulations.

Energy Source Procurement and Dispatching Policies

Short Term Activities

The MISO is a fully integrated regional transmission organization that operates a Day-Ahead Energy and Ancillary Services Market, a Real-Time Energy and Ancillary Services Market, a Financial Transmission Rights (“FTR”) Market, and a Planning Resource Auction for capacity.

Minnesota Power’s generation resources, load, and transmission assets are located within the MISO footprint and are part of the MISO market. The MISO markets are used to balance generation with load and to hedge congestion between generation and load. There are a variety of tools that Minnesota Power uses to help with analysis and participation in the MISO market. Minnesota Power offers to sell energy and ancillary services sourced from its supply resources and bids to buy energy to serve load in the MISO market each day. MISO procures enough market ancillary service products to meet the needs of the entire footprint and the Company is allocated its load ratio share of the costs to procure the needed ancillary services. If market clearing prices are above Minnesota Power’s generator offer prices, Minnesota Power generation will be selected to serve load. If market prices are below the generator offers, other lower cost resources will be selected to serve Minnesota Power’s load, and the Company’s generation will be backed down. The Company also looks to buy energy in the short-term bilateral market when there is an energy need and purchases can be made below expected MISO day-ahead costs.

Medium Term Activities

Minnesota Power uses a production cost model to determine its forward monthly energy position. Model inputs include forecasted customer loads, generator capabilities, contract energy purchases and sales, forward energy prices, planned generator outages, and forced and maintenance outage rates. Inputs are updated and the model is run periodically to determine Minnesota Power's forward energy position.

Planned generator outages are usually planned two years in advance. When a significant energy deficit is identified, the Company monitors the wholesale market for least cost supply opportunities and enters into bilateral purchases to maintain volumetric position limits as outlined in Minnesota Power's Power Marketing Risk Management Policy. If forward energy prices drop below forecasted spot market prices the entire short position could be covered with a bilateral purchase prior to the start of the outage. If lower cost energy is available in the areas that border the MISO north region, Minnesota Power may choose to use bilateral purchases from those border areas to cover a generator outage.

Summary of Fuel Contracts

Coal Contracts

Kennecott Coal Sales LLC, an Oregon LLC (currently known as Navajo Transitional Energy Company, and formerly known as both Cloud Peak Energy and Rio Tinto Energy), Spring Creek Mine, Decker, Montana.

- Master Coal Purchase Agreement signed on [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] provides general terms and definitions governing purchases and sales of coal.
- An agreement signed on [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] also provides for purchases of a minimum of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] tons of coal for the period of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Arch Coal Sales, Black Thunder Mine, Wright, Wyoming

- Master Coal Purchase Agreement signed on [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] provides general terms and definitions governing purchases and sales of coal.
- An agreement signed on [TRADE SECRET DATA BEGINS July 24, 2024 TRADE SECRET DATA ENDS] also provides for purchases of a minimum of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] tons of coal for the period of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS].

Peabody CoalSales, LLC., St. Louis, Missouri, Caballo Mine, Campbell County, Wyoming

- Coal Supply Agreement signed on [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] provides general terms and definitions governing purchases and sales of coal.
- An agreement signed on [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] also provides for purchases of a minimum of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] tons of coal for the period of [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS] to [TRADE SECRET DATA BEGINS [REDACTED] TRADE SECRET DATA ENDS].

Biomass Contracts

Currently Minnesota Power purchases the majority of its wood fuel under purchase orders with 15 separate suppliers for use at the Hibbard Renewable Energy Center with varying expiration dates. In addition, Hibbard has the following biomass contracts:

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Savanna Pallets Inc.

- An agreement signed on [TRADE SECRET DATA BEGINS ██████████
TRADE SECRET DATA ENDS] provides for the purchase of biomass fuel from [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] for a minimum of [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] tons per year and a maximum of [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] tons per year.

McCabe Forest Products

- An agreement signed on [TRADE SECRET DATA BEGINS ██████████
TRADE SECRET DATA ENDS] provides for the purchase of biomass fuel supply and storage from [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS ██████████
██████ TRADE SECRET DATA ENDS] for up to [TRADE SECRET DATA BEGINS ██████████
██████ TRADE SECRET DATA ENDS] tons per year in storage.

Rail Contracts

Burlington Northern Santa Fe (currently known as BNSF Railway)

- An agreement signed on [TRADE SECRET DATA BEGINS ██████████
TRADE SECRET DATA ENDS] provides for the transportation of coal from [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] for a minimum of [TRADE SECRET DATA BEGINS ██████████
██████ TRADE SECRET DATA ENDS] tons per year and a maximum of [TRADE SECRET DATA BEGINS ██████████
██████ TRADE SECRET DATA ENDS] tons per year.

Supplemental Fuels

Minnesota Power uses natural gas for start-up and flame stabilization at the Boswell Station. Minnesota Power gets daily gas pricing from a supplier for natural gas at the

Boswell Station. Minnesota Power also purchases natural gas for start-up, flame stabilization, as well as generation at the Hibbard Station. Minnesota Power purchases natural gas for the Hibbard Station from the City of Duluth Comfort Systems. At the Laskin Station, gas is purchased from BP as part of a gas management service contract. This agreement provides services from [TRADE SECRET DATA BEGINS ██████████
TRADE SECRET DATA ENDS] through [TRADE SECRET DATA BEGINS ██████████
██████████ TRADE SECRET DATA ENDS].

D. Rule 7825.2810 Annual Report: Automatic Adjustment Charges

Attachment 2 – Automatic Retail Fuel Adjustment Charges TS includes Minnesota Power’s forecasted to actual comparison of Automatic Adjustment Charges for the period of January 2025 through December 2025.

The 2025 forecast rates were based on forecasted sales of 8,997,900 MWh and forecasted fuel costs of \$271.6 million. The Company’s actual 2025 sales were 8,192,436MWh and actual fuel costs were \$252.5million.

On December 23, 2019 the Commission issued its Order in Docket Nos. E015/MR-19-443 and E015/GR-19-442 approving the Company’s proposed changes to the base cost of energy. The Company moved all fuel related costs to the Fuel and Purchased Energy Charge, with zero cost of fuel in the base energy rate, effective January 1, 2020.

E. Rule 7825.2820 Annual Auditor’s Report

Attachment 1 – Report of Independent Accountants includes the Independent Auditor’s Report on Minnesota Power’s accounting for automatic adjustments during the period of January 2025 through December 2025.

F. Rule 7825.2830 Annual Five-Year Projection

The annual five-year projection is part of the Company’s FAC Forecast filing which is filed annually on May 1.

G. Rule 7825.2840 Annual Notice of Reports Availability

Attachment 10 – Notice of Reports Availability includes the service lists of the interveners in the previous two general rate cases.

H. Other Reports and Information included in the 2025 FAC True-up

Attachment No. 3 – Monthly MISO Day 2 Charges and Allocation

Attachment No. 3 provides a spreadsheet detailing the monthly MISO Day 2 charges and their allocation, along with a year-end summary. The attachment categorizes sales volumes into the following:

- FAC Retail – Sales MWh subject to the retail FAC allocation. This category includes residential, commercial, industrial, and seasonal load classes.
- FAC Resale – Sales MWh subject to the resale FAC allocation. This category includes municipal customers, such as the City of Nashwauk and the City of Proctor, that are allocated the base energy fuel adjustment clause and the monthly energy fuel adjustment clause.
- Other – This category includes contracted sales, MISO Market sales, and liquidation.

The 2025 FAC Forecast versus actuals for MISO costs is described below:

- Energy Charges – Asset Energy is reflected in MISO market purchases and sales. Because of this, Minnesota Power did not include amounts on Attachment No. 3 of the 2025 forecast. For actuals, Minnesota Power is able to break out the Asset Energy between the various charge types, which are included in the Energy Charges line on Attachment No. 3 of the 2025 True Up.
- FTRs and Auction Revenue Rights (“ARR”) – The 2025 ARR/FTR charges came in lower than expected due to lower price spreads between generation and load on paths where Minnesota Power had self-scheduled FTRs.
- Revenue Sufficiency Guarantee (“RSG”) and Make Whole Payments – The variance in RSG and Make Whole Payments is mainly due to the fact that some of Minnesota Power’s generating units were called on for reliability purposes more than what was anticipated in the 2025 FAC Forecast. This resulted in more Real Time Revenue Sufficiency Guarantee Make Whole Payments to Minnesota Power, helping offset some of the distribution charges associated with RSG.
- Revenue Neutrality Uplift (“RNU”) Charges – The RNU charges were higher than forecast mainly due to the forecast being based on a three-year average of prior

staff have participated in reliability training programs that teach students the best practices of equipment maintenance along with the tools needed to be proactive rather than reactive to ensure equipment reliability. Program elements include condition monitoring, vibration analysis, system and components, troubleshooting, precision equipment installation and assembly, instrument and process variability, and root cause failure analysis. Additionally, the Company has increased its expectations and requirements around specifications of new and rebuilt equipment and parts with enhanced use of overhaul specifications and visits to repair shops by engineers and technicians.

Minnesota Power's Outage Planning process continues to be a focal area. A systematic approach to outage planning with improved tools has resulted in projects being safely and efficiently executed while ensuring equipment reliability. Outage duration is set based on project scope with project milestones identified, resources allocated, materials ordered, and safety plans in place. Automated reports allow for better coordination, communication, budget management, and analysis of work required. For example, inspection activities that can only be performed with the unit offline are identified so they can be scheduled as early as possible in an outage to allow time to complete work within the outage window.

The Company continues to implement a program called Operational Excellence. The focus of Operational Excellence is to teach Human and Organizational Performance tools to employees (three-way communication, Peer Checking, Labeling, Procedure Use and Adherence, etc.) resulting in increased elimination of potential errors occurring in the field. In addition to the Human and Organizational Performance tool usage, an "intentional learning" process is completed when an event occurs, and those learnings are shared throughout the facilities.

Tube Leaks

Tube leaks are statistically the most common cause of outages in coal-fired power plants. The most common causes of tube leaks are:

- Thermal fatigue
- Soot blower erosion
- Fly ash erosion
- Chemical attack

Thermal Fatigue

Thermal fatigue manifests itself as cracking of the boiler tubes - sometimes as very small "micro" cracks and sometimes as large cracks. This occurs as a result of changing boiler temperatures, usually when the boiler swings up or down to follow load and when the boilers start up and shut down. This is a similar effect to bending a paper clip back and forth - after so many cycles it eventually breaks. Minimizing boiler "swings" (base loading) helps minimize the impact of thermal fatigue. However, with the increasing impacts of intermittent wind generation, the Company is seeing more and more swings in output.

Soot Blower Erosion

Soot blower erosion occurs in areas where soot blowers are used to 'blow off' ash or slag which accumulates on boiler tubes. Soot blowers use high pressure steam or high-pressure air to do the cleaning. The ash removal is necessary to improve heat transfer which improves boiler thermal efficiency. Common practices to mitigate soot blower erosion are to add a weld overlay (commonly called "pad welding") to existing tubes, add tube shields which are essential sacrificial attachments to the tubes, changing soot blower media pressure (usually not an option) and tube replacement in the affected areas. The use of the soot blowers is essential in keeping the units online. Coal composition can differ from mine to mine or even within the same mine. As Minnesota Power looks to find the best low-cost fuel blend for customers, certain coals may cause more fouling than others. The increased potential of this fouling requires both the frequency and duration of soot blowing to increase, which minimizes the buildup on the boiler tubes. The Company is increasingly using higher alloy weld overlay to provide increased tube longevity.

Fly Ash Erosion

Fly ash erosion occurs when fly ash and combustion gases pass rapidly across superheated boiler tube surfaces. Because of the abrasiveness of fly ash, the surface of boiler tubes in the high flow areas slowly erode. Many things contribute to the amount of erosion, such as gas path restrictions (plugging - see reasons for soot blowing above), variations in coal quality (higher ash content), other additives which are added to the fuel mix typically for emission control, etc.

Chemical Attack

Chemical attack is becoming a common source of tube failures due to the corrosiveness of many of the additives being used to control emissions. When these chemicals come in contact with very hot boiler tubes, their normal corrosiveness is significantly increased. Since there tend to be few options for using alternate less corrosive additives, a common solution is to look at tube materials which perform better in the corrosive environment. This is usually a very expensive fix and can have environmental compliance implications.

Minnesota Power has a boiler reliability program which is very effective in proactively identifying areas of the boilers where tube leaks are likely to occur and minimizing that risk with proactive maintenance practices. The program uses a combination of visual inspections, non-destructive testing methods (“NDT”), tube sample analysis, tube failure history, and industry experiences to avoid forced outages due to unexpected tube leaks. Minnesota Power also has its own Boiler Weld Repair Program that ensures all applicable codes and standards are met when boiler repairs are performed.

For perspective on the challenges with boiler reliability programs, consider the following:

- Boswell-3 boiler has 473,891 ft (89.7 miles) of varying diameter boiler tubes
- Boswell-4 boiler has 779,905 ft (147.6 miles) of varying diameter boiler tubes

The boiler tube surface area where a leak can occur is several hundred thousand square feet in either boiler.

A tube leak usually begins as a very small hole (0.10 inch or less) in the tube wall which can expand rapidly due to high temperatures and pressure. Considering the huge surface area in a boiler and the very small size of the hole or microscopic crack which results in a tube leak, it is very difficult to effectively screen the entire boiler to prevent all tube leaks. As part of the Company's boiler reliability program, whenever there is an opportunity to get into the boiler to do an inspection – a forced or scheduled outage – critical areas are inspected to evaluate erosion rates and to determine if repairs are needed. This information is used to plan for future capital expenditures to help minimize future tube leaks. During these inspection opportunities, small leaks are sometimes found and repaired. Similar proactive maintenance practices are routinely followed at the other Minnesota Power thermal facilities.

Non Boiler Related Outages

Minnesota Power has a Generation Reliability Group that is dedicated to monitoring and improving the reliability of not only the boiler but also the rotating equipment. The group is comprised of boiler, turbine and pulverizer engineers/specialists as well as specialists in predictive maintenance technologies. They work daily with the operating and maintenance groups at all facilities to improve the daily operating practices, planning for work and repairs to occur in future outages and establishing 5- and 10-year maintenance plans.

Rotating equipment that is monitored through various predictive technologies is summarized in a monthly reliability meeting with the specific plant. The manager is provided with a monthly scorecard as to their performance as well as identifying concerns and upcoming needs.

Mechanisms for Information Sharing

Minnesota Power is open to sharing lessons learned on a generic basis with the other utilities on an annual basis.

However, the concept of sharing lessons learned is more attractive in theory than in practice. Each utility's generating units are unique (manufacturer, date of installation, fuel

type and mixture, base loaded vs. cyclic loading etc.), as is each company's operation and maintenance practices. Furthermore, sharing best practices regarding planned outages over and above what companies have already described in public filings borders on releasing confidential information about outage planning and energy marketing. This could harm that utility's customers if it were made available to other parties, since those practices provide the utility with its best protection in acquiring replacement energy at the lowest cost possible.

Minnesota Power will continue to provide information on forced outages and what steps, if any, could have helped in avoiding or alleviating outages.

Plant Outage Contingency Plans to address the following for the period of January 2025 through December 2025:

1. Identification for the period of January 2025 through December 2025 any and all contractors (and associated contracts) that increased replacement energy costs due to an extension of the plant outage days as a result of delays and/or lack of performance.

During this period, there were no delays or lack of performance by contractors identified which impacted the length of the outages and/or the replacement energy costs.

2. Please provide a narrative fully explaining the reasons for the delays and/or lack of performance for each of the contracts identified above.

Not applicable.

3. Please describe the lessons learned and the contingency plans developed by the Company to mitigate against future risk of delays or lack of performance, when contractors perform poorly and increase costs during plant outages.

Not applicable.

Included in Attachment 5 TS is an event log of the Company's unplanned outages and associated costs.

Attachment No. 6 – Annual ASM Charges and Summary

Overview

Minnesota Power has been participating in MISO's Ancillary Service Market ("ASM") since it started on January 6, 2009. Since market start, Minnesota Power has not seen any major changes to operation or clearing our units for energy in the market. The Company has had some additional opportunities in the ASM to optimize generation portfolio revenues by providing regulation and spinning reserve without creating a negative impact on available energy necessary to meet customer needs.

Spinning Reserves

Currently, Minnesota Power has 7 generating resources that are qualified to supply energy, regulation, and spinning reserves service for MISO. Under normal operating conditions Minnesota Power has the potential of carrying approximately 92 MW of spinning reserves above the cruise operating level on these generation facilities without reducing energy available for customers. Prior to the ASM, Minnesota Power's share of the spinning reserves obligation was 21 MW. Under ASM, Minnesota Power can currently clear up to approximately 10 MW of spinning reserves on thermal generation without impacting energy availability. The additional ancillary service revenues reduce overall customer costs because the spinning reserve revenues are allocated to the FAC through our MISO allocation process.

The ASM has also added value for customers when generating units have backed down to minimum generation levels due to low energy prices. The generators can be backed down and still provide spinning reserves at the lower operating levels. MISO could also back down generation to acquire the market's required spinning reserves, however to date Minnesota Power's thermal generators have been almost exclusively selected to supply energy and have not been backed down to supply spinning reserves.

Including ASM charge type impact only, MISO's Spinning Reserves process had a net gain of \$131,586.82 for January 2025 through December 2025. The Spinning Reserve costs and revenues are provided in Table 6-A.

Supplemental Reserves

Minnesota Power's cost allocation for supplemental reserves was \$76,371.82 for January 2025 through December 2025. Prior to the ASM, Minnesota Power utilized interruptible loads at large power customers to cover supplemental reserves requirements. Due to low prices for this product under ASM, Minnesota Power has elected not to offer MISO supplemental reserves from large industrial customers because the benefit is too small for the risk it provides to customers. The impact to customers due to lost production if interrupted for deployment of supplemental reserves greatly exceeds the cost of purchasing supplemental reserves from MISO. Minnesota Power will continue to monitor prices and work with customers as conditions change to see if supplying additional supplemental reserves is appropriate in the future. The Supplemental Reserve costs and revenues are provided in Table 6-A.

Regulation

Prior to ASM, Minnesota Power scheduled approximately 8 MW of regulation on its system on an hourly basis to meet Balancing Authority control performance criteria requirements. Under ASM, Minnesota Power units are only selected by MISO for regulation when it is cost effective. Most of the time the Company's units are cleared for energy instead of being held back to provide the 8 MW used to reserve for regulation. Under ASM, due to regulation clearing and the ability to purchase affordable regulation service, Minnesota Power has more economic energy available from its low cost generation facilities to serve its customers. Including ASM charge type impact only, MISO's Regulation process had a net gain of \$173,819.28 for January 2025 through December 2025. The Regulation costs and revenues are provided in Table 6-A.

ASM Charge Summary

Operation in the ASM market has been smooth and there continues to be a positive economic benefit for Minnesota Power's customers. The Company is now able to maximize the capabilities of its units to a greater extent, which ultimately has led to greater operational efficiencies for Minnesota Power. The Company has developed many tools and reports to track the benefit of the ASM on a unit by unit and day by day basis. Minnesota Power's overall strategy is to continue to develop strategies in the ASM that have a positive impact for customers.

Minnesota Power reviews all MISO charges and credits including ASM charge types on a daily basis. Table 6-A provides the January 2025 through December 2025 summary of ASM hourly charges which had a net loss of \$307,850.83. Minnesota Power allocates all ASM charges in the same manner as it has allocated MISO Day 2 charge types – on a per MWh approach netting costs and benefits of the various charges. During January 2025 through December 2025, a net loss of \$786,113.47 was allocated to the Retail FAC.

Table 6-B provides a summary of January 2005 through December 2025 hourly MWh related to ASM products. The table provides Minnesota Power's net position for each of the three ASM products which indicates that Minnesota Power was a net buyer of Supplemental Reserves and a net seller of Regulation and Spin Reserves for January 2025 through December 2025.

Schedule 17 Costs

MISO took on additional responsibilities with the start of the ASM and related to the increased systems responsibilities and analysis; additional costs were incurred at MISO. These costs were recovered from Market Participants including Minnesota Power through increased Schedule 17 charges. Table 6-C provides a summary of the Schedule 17 costs before and after the start of ASM. Prior to the start of ASM, Schedule 17 rates averaged \$0.07223 for an average monthly billing of \$140,922.50 per month. For January 2025 through December 2025, the Schedule 17 rate averaged \$0.08729 for an average monthly billing of \$165,391.73.

Contingency Reserve Deployment Failure Charge (“CRDFC”)

For the period of January 2025 through December 2025, Minnesota Power incurred \$870.54 of CRDFC. This charge occurred on four operating days as shown in Table 6-E. The shortfall MWhs totaled 9.7 for an average cost of \$89.75 per MWh of shortfall.

During all other CRD events, Minnesota Power’s generating units responded to the reserve deployments; however, in this instance Minnesota Power fell short of delivering 100 percent of the energy requested.

Real Time Excessive Deficient Energy Deployment Charge Amount (“EDED”) (“EDED”) (“EDED”)

For the period of January 2025 through December 2025, Minnesota Power incurred \$514,605.58 in EDED as shown in Table 6-A. The majority of the instances when EDED occurs are from Failure Mileage Charge and Flag instances which are when a unit fails a Regulation Mileage Performance Test for 4 consecutive intervals within one hour.

Attachment No. 7 – Wind Curtailment Reporting

Attachment No. 7 – Wind Curtailment Reporting TS shows wind curtailment reporting for Oliver I and II, Bison Wind Energy, and Nobles 2 Wind Energy.

Attachment No. 8 – Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (“IOUs”)

Attachment No. 8 - Offsetting Revenues and/or Compensation Received by IOUs TS includes data showing Minnesota Power’s offsetting revenues for the reporting period of January 1, 2025, through December 31, 2025.

Attachment No. 9 – Generation Facilities Maintenance Expense Report

Attachment No. 9 includes data showing generation facilities maintenance expenses.

III. 2025 FPE FORECAST TO ACTUALS

Minnesota Power proposes an FPE Rider True-up charge of \$3.5 million. The under-collection was driven by lower than forecasted generation that was replaced by higher priced market purchases, which impacted 2025 fuel costs. Actual 2025 Locational Market Prices (“2025 LMPs”) were approximately 20% higher than forecast and close to 59% higher than 2024, increasing the MISO market purchase price. Wind and hydro generation in 2025 was also below forecast; these zero-fuel cost resources were replaced by higher cost market purchases and company generation which increased total costs for 2025. The under-collection was compounded by a reduction in 2025 actuals sales: total sales declined roughly 9%, driven by a decrease in Large Power mining sales. Overall total fuel costs were slightly below forecast, but on a \$/MWh basis actual fuel costs were 2% higher than forecast, which led to the under-collection.

The proposed 2025 FPE Rider True-up is in part based on a comparison of the 2025 FAC forecast to actual fuel and purchases as summarized below. Additional information on the 2025 FPE calculation and the under recovered amount of \$3.5 million related to 2025 actuals and the 2024 FPE Rider True-Up balance can be found in Attachment 2 – Automatic Retail Fuel Adjustment Charges TS.

Table 1: Fuel Cost Summary

	2025 Forecast	2025 Actual	Difference
Company’s Generating Stations	\$131,822,689	\$135,562,244	\$3,739,555
Plus: Purchased Energy	\$228,880,278	\$245,300,420	\$16,420,143
Plus: MISO Charges	\$39,304,154	\$42,415,048	\$3,110,894
Plus: Reagent Expenses	\$4,925,978	\$4,927,028	\$1,050
Plus: NOx Charges	\$0	\$0	\$0
Less: MISO Schedules 16, 17 & 24	\$(306,699)	\$(840,768)	\$(534,069)
Less: Fuel Cost Recovered through Inter System Sales	\$132,433,585	\$176,631,581	\$44,197,995
Less: Costs Related to Solar	\$2,597,139	\$2,199,704	\$(397,436)
Plus: Time of Generation and Solar Energy Adjustment	\$1,387,347	\$2,242,109	\$854,762
Total Cost of Fuel	\$271,596,420¹	\$252,456,333	\$(19,140,087)
Total Fuel Clause Sales (MWhs)	8,997,900	8,192,436	(805,464)
Average Cost of Fuel	\$30.18	\$30.82	\$0.63

¹ Approved by Commission Order dated November 8, 2024 in Docket No. E015/AA-24-64, and November 25, 2024 in Docket No. E015.GR-23-155.

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A. Sales

Customer sales decreased by 805,464 MWhs, or 9 percent, under forecasted sales mainly due to decreased Large Power Taconite and Paper and Pulp sales. In addition, Inter System sales increased by 721,724 MWhs mainly due to increased MISO market sales and Retail Loss of Load sales. Inter System sales are removed from the Total Sales of Electricity as they are non-FAC MWhs. Minnesota Power used the RTSim production cost model to determine the volume and cost of MISO market sales used in the forecast. Actuals are looked at hourly so there will be hours where Minnesota Power is a net seller and hours when Minnesota Power is a net purchaser which creates market purchases and sales in a month.

Table 2: Sales Comparison

2025 Sales (MWh)	Forecasted Sales	Actual Sales	Difference
Total Sales of Electricity	12,710,739	12,619,493	(91,246)
Residential	1,040,641	1,014,950	(25,691)
Commercial	1,202,801	1,157,055	(45,746)
Large Power Taconite	4,190,960	3,462,018	(728,942)
Large Power Paper and Pulp	601,791	566,135	(35,656)
Large Power Pipeline	321,073	319,824	(1,249)
Other Miscellaneous	318,858	315,888	(2,970)
Municipals	1,378,882	1,406,168	27,286
Inter System Sales	3,655,733	4,377,457	721,724
Less: Inter System Sales	3,655,733	4,377,457	721,724
Customer Intersystem Sales	1,011,240	907,534	(103,706)
Market Sales	2,640,408	3,107,070	466,662
Station Service	4,085	4,833	748
Sales due to Retail and Resale Loss of Load	-	358,020	358,020
Less: Solar Generation & Purchases	57,106	49,601	(7,505)
Total Fuel Clause Sales	8,997,900	8,192,436	(805,464)

B. Generation

Minnesota Power saw a decrease of [TRADE SECRET DATA BEGINS ██████████ TRADE SECRET DATA ENDS] of generation during 2025. Company wind and hydro generation came in below forecast due to lower wind production than forecasted. Also, Minnesota was in a drought most of 2025 which caused low hydro generation throughout

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2025. Minnesota Power did have higher thermal generation than forecast due to high market prices, transmission outages, and a reduction in MISO market imports which resulted in higher priced generation being dispatched in the Company’s region.

Table 3: Generation MWh Comparison

2025 Generation (MWh)	Forecasted Generation	Actual Generation	Difference
	[TRADE SECRET DATA BEGINS		
Boswell Unit 3	[REDACTED]		
Boswell Unit 4			
Hibbard			
Laskin			
Wind			
Hydro			
Total			

C. MISO Market Pricing and Congestion

The lower priced and less volatile market that was seen in 2023 and 2024 flipped in 2025 as market prices came in 20% above forecast and 59% above 2024.

Table 4 below compares the average MISO Market price used in the 2025 forecast to actual average MISO Market prices.

Table 4: Average Market Price Comparison- DA LMP at MP.MP

\$/MWh	2025 Forecast	2025 Actual	Difference
	[TRADE SECRET DATA BEGINS		
Average Market Price	[REDACTED]	[REDACTED]	[REDACTED]
]TRADE SECRET DATA ENDS]		

D. What is Minnesota Power Doing to Control Congestion Costs

Short Term:

[TRADE SECRET DATA BEGINS [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]

[REDACTED]

TRADE SECRET DATA ENDS]

Minnesota Power will continue to optimize the use of its HVDC transmission line to cost-effectively deliver its 600 MW wind portfolio in North Dakota to customers. Minnesota Power’s HVDC line operates like a physical FTR, providing a financial mechanism that reduces congestion cost for customers. The HVDC line is an important congestion mitigation asset that Minnesota Power is using today to manage customer cost. In October 2024 the Company received a Certificate of Need and Route Permit to modernize and upgrade its HVDC terminals and interconnect the upgraded HVDC terminals to the existing alternating-current (“AC”) transmission system. The HVDC terminals have been operating successfully for more than 47 years – well beyond its 30-year design life. As the HVDC system continues to experience increased unplanned terminal outages due to failures with aging components, modernizing the HVDC terminals will allow Minnesota Power to continue delivering these cost-savings for customers.

Minnesota Power is taking an “all of the above” approach and has explored options to mitigate cost impacts to customers, by optimizing FTRs, transmission assets (i.e. HVDC), and as discussed below, working with other Minnesota utilities and MISO to identify transmission related projects that reduce congestion cost. As part of the “all of the above” strategy, in 2024 Minnesota Power entered into a unique contract with NewGrid, a consulting firm that provides services to identify system congestion events that impact Minnesota Power’s generation portfolio and the FAC. The Company worked with NewGrid

on evaluating an opportunity to reduce congestion costs for a wind facility in southwest Minnesota that has a Purchase Power Agreement with Minnesota Power. NewGrid's work showed promise as an approach to reduce congestion with targeted operational reconfiguration of the transmission system and working with other transmission owners in the region. The reconfiguration recommendations are designed to maximize the transmission system capabilities in the near term and are not intended to replace recommendations for long-term transmission studies. The reconfiguration is intended to reduce congestion for serving load while maintaining all transmission planning and operation best practices and standards. Through this work with NewGrid the Company developed an understanding on how the NewGrid alternative configuration study work could be presented to a transmission owner. The NewGrid study work included a congestion savings estimate, which has the challenge of simulating the system congestion with and without the alternative configuration. Minnesota Power participated in a reconfiguration request where the transmission owner didn't take any action due to the complexity of needing to update a system stability study. Minnesota Power recognizes that operating the system safely and reliably is critical and having a third-party propose a reconfiguration solution can be a challenge to make sure there aren't any unintended consequences from the recommended configuration. Another challenge is studying and implementing solutions with adequate lead time prior to a known event occurring (i.e. transmission outage for maintenance) so the congestion savings can be realized. NewGrid has had success working with other utilities on mitigating congestion, although, in 2025 Minnesota Power did not extend the contract due to challenges noted above. Minnesota Power continues to have discussions with NewGrid and the Company will continue to evaluate the value of working with NewGrid in the future.

There is currently a misalignment in the cost recovery for NewGrid consulting service fees through base rates and the benefits of reduced congestion costs customers receive through the FAC. At the time of the 2024 FAC True-Up filing, Minnesota Power was considering a miscellaneous petition requesting to align the consulting cost with the associated benefits. Given Minnesota Power did not extend the contract with NewGrid there are no current plans to submit a miscellaneous petition. This still remains a cost

recovery concern, and the Company may consider a petition in the future if the Company engages with NewGrid again and there are demonstrated benefits through reduced congestion costs.

In 2023 Minnesota Power participated in a study with neighboring utilities to identify transmission solutions to reduce congestion cost. Grid North Partners, a joint initiative of utilities in Minnesota, Wisconsin, South Dakota, and North Dakota, performed an elective study in 2023 to identify and develop near-term solutions to incrementally resolve congestion. The Grid North Partners Tech Team collectively analyzed both historical and forward-looking congestion, identified physical limiting equipment on every congested element, and forecasted congestion relief for each solution. The Tech Team identified 19 congestion relief solutions with a cost of \$130 million, which will provide an expected congestion benefit of more than \$300 million, a greater than 2:1 benefit to cost ratio. Expected in-service dates range from 2023-2026 for solutions developed by Grid North Partners. In part, due to the success of the 2023 Grid North Partners congestion study, a legislative requirement by the State of Minnesota was enacted that requires similar study work to be performed by transmission owners within the state. This analysis was performed by the Grid North Partners group in 2025.

Two of the identified congestion relief solutions from the 2023 study work were on Minnesota Power facilities, the Blackberry – Riverton 230 kV line and the Forbes – Iron Range 230 kV line. Based on analysis of the historical and projected congestion on these facilities, along with the equipment ratings comprising the facilities, Minnesota Power determined that Ambient-Adjusted Ratings should be developed. Ambient-Adjusted Ratings are facility ratings calculated using actual ambient temperatures, rather than the default seasonal temperature assumptions. Ambient-Adjusted Ratings provide for potential increased ratings and reduced congestion as ambient conditions allow, without capital costs. Minnesota Power developed and implemented both Ambient-Adjusted Ratings sets in March 2023. Minnesota Power currently has a total of 19 transmission lines that have Ambient-Adjusted ratings developed for real-time use in operations.

Medium Term:

As noted above, in 2025 Minnesota Power participated in a study with neighboring utilities within the Grid North Partners group to identify transmission solutions, specifically Grid Enhancing Technologies (“GETs”) to address congestion throughout Minnesota. The study reviewed historical congestion that occurred in the previous three years, and forecasted congestion based on the years 2026 and 2030. These congestion costs were used to determine cost effective potential solutions. The Report was filed in conjunction with the 2025 Biennial Transmission Plan Report in October 2025.²

Four Minnesota Power facilities were included in the section for Constraints with Solution Proposals (Payback Period Threshold Met). These facilities were determined to be a good fit for GETs solutions, specifically the application of dynamic line ratings. It should be noted that additional upgrades to other limiting equipment to maximize the benefits from the GETs solution could be required. Minnesota Power is actively working towards implementing a targeted deployment of dynamic line ratings in 2026 that will include several of the facilities included in the GETs report.

Minnesota Power anticipates there will be reduced congestion as part of FERC Order 881 compliance, which requires all transmission providers to use Ambient-Adjusted Ratings as the basis for evaluating near-term transmission service. The order was issued with a compliance date of July 2025, although MISO filed and was granted an extension request in June 2025 with a final implementation date of no later than December 31, 2028. When in place, operating and near-term limits will take into account ambient air temperatures as well as solar heating impacts. Minnesota Power anticipates more renewable energy will be allowed to flow across congested transmission corridors resulting in lower congestion cost across the system.

Minnesota Power continues to stay engaged with neighboring utilities on efforts being made to reduce congestion in the medium-term.

² <https://efiling.web.commerce.state.mn.us/documents/%7B10AD439A-0000-CE1F-BEE7-A9B18652A80F%7D/download?contentSequence=0&rowIndex=6>

Long Term:

Minnesota Power continues to work with MISO on future transmission additions through the Long Range Transmission Plan (“LRTP”). The LRTP Tranche 1 and Tranche 2.1 portfolios have several new transmission projects identified in Minnesota and North Dakota. MISO expects the addition of the LRTP Tranche 1 and 2.1 Portfolios to increase the operational flexibility to better allow timely outage scheduling to maintain the reliability of the system and to reduce the economic impacts due to congestion caused by outages. The new transmission paths also help reduce market price volatility by providing access to a broader pool of generation resources, including dispatchable and renewable generation resources. According to MISO’s analysis, the LRTP Tranche 1 Portfolio is expected to provide economic savings more than two times the total cost of the portfolio and the LRTP Tranche 2.1 Portfolio is expected to provide similar economic savings and increased reliability of the grid.

In August 2023, Minnesota Power and Great River Energy filed a combined Certificate of Need and Route Permit Application for the Northland Reliability Project (LRTP Project #3), both of which were granted by the Commission in a February 2025 order.³ Analysis produced by Minnesota Power and Great River Energy in the application identified that by itself, the Northland Reliability Project is projected to provide approximately \$127 million to \$2.1 billion in economic savings over the first twenty years of the Project’s service by reducing system congestion and providing access to lower cost generation. These economic savings will help offset the capital cost of the Project.

In January 2026, Minnesota Power and American Transmission Company submitted an application for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead (“ISA”) 345 kV Transmission Line Project.⁴ The ISA project was studied, reviewed, and approved by MISO as part of its LRTP Tranche 2.1 portfolio of projects included in MISO’s 2024 Transmission Expansion Plan (“MTEP24”). The Project, as part of the LRTP Tranche 2.1 portfolio, is needed to enhance grid reliability in the

³ Dockets Nos. E015, ET2/CN-22-416 and ET2/TL-22-415

⁴ Docket No. E015 /CN-25-111 and E015/TL-25-112

Upper Midwest as grid operating conditions become more variable, to increase grid efficiency and regional transfer capability as energy is transferred from where it is produced to where it is needed, and to meet the growing demand for reliable clean energy in the Upper Midwest.

In January 2026, Minnesota Power, Otter Tail Power Company, and Great River Energy filed an application with the Minnesota Public Utilities Commission for a Certificate of Need to build the Maple River – Cuyuna 345 kilovolt Transmission Project (“Maple River – Cuyuna Project”),⁵ a high-voltage transmission line that will stretch about 160-180 miles from Minnesota Power’s Cuyuna Substation near Riverton, Minnesota, to Otter Tail Power Company’s Maple River substation near Fargo, North Dakota. The Maple River – Cuyuna Project was approved by MISO as part of its LRTP Tranche 2.1 portfolio and is needed to support the reliability of the regional transmission system, particularly in northern Minnesota and eastern North Dakota. The Maple River-Cuyuna Project will provide additional transmission capacity and regional transfer capability to reliably integrate future generation resources, meet growing electrical demand, enhance resiliency during extreme weather events, and enable cost-effective regional energy transfers supporting economical grid operations.

Minnesota Power anticipates that congestion cost will be lower due to the LRTP projects being placed into service in the 2030-2033 timeframe. However, it is important to note that the magnitude of congestion reduction can vary, especially if new wind and solar builds outpace the capability of new transmission in the area. Building new transmission to better distribute energy production from renewable rich regions will be needed to reduce congestion cost as Minnesota moves towards meeting the Carbon Free Standard.

IV. CONCLUSION

Minnesota Power submits this annual true-up report and proposed FPE Rider True-up collection of \$3.5 million (\$3.9 million 2025 under recovery plus the 2023 FAC true up

⁵ Docket No. E015,ET2,E017/CN-25-109 and

refund balance of \$504,765) pursuant to the Commission's rules regarding Automatic Adjustment of Charges and Docket No. E999/CI-03-802.

Dated: March 2, 2026

Respectfully Submitted,

A handwritten signature in black ink, appearing to read 'A. Vang', with a long, sweeping flourish extending to the right.

Analeisha Vang
Regulatory Compliance Specialist, Senior
Minnesota Power
30 W. Superior Street
Duluth, MN 55802

Attachment 1
Report of Independent Accountants



Report of Independent Accountants

To the Management of ALLETE, Inc.:

We have performed the procedures enumerated below, which were agreed to by ALLETE, Inc. (the “Company,” as the engaging party) and the Minnesota Public Utilities Commission (the “MPUC”), solely to assist you in evaluating compliance with rule 7825.2820 of the Rules of the MPUC governing Automatic Adjustment Charges. The Company is responsible for Section A of Minnesota Power’s Annual Report of Automatic Adjustment Charges for the period January 1, 2025 through December 31, 2025 found in Attachment No. 2 (Section A) of the Company’s Annual Reports Containing Fuel Information and Data (the “Annual Report”) pursuant to MPUC Rules 7825.2800 – 7825.2840 and we have no responsibility for verification of any underlying data.

In an agreed-upon procedures engagement, we perform specific procedures that the Company has agreed to and acknowledged to be appropriate for the intended purpose of the engagement, and we report on findings based on the procedures performed. The procedures performed may not address all the items of interest to a user of this report and may not meet the needs of all users of this report and, as such, users are responsible for determining whether the procedures performed are appropriate for their purposes. The parties specified in this report have agreed to and acknowledged that the procedures performed are appropriate for their purposes. This report may not be suitable for any other purpose.

The procedures performed and results thereof are as follows

1. For the period January 1, 2025 through December 31, 2025, we compared 16 haphazardly selected invoices, received from the Company's energy providers to the amount recorded and paid by the Company and determined they were in agreement.
2. For the period January 1, 2025 through December 31, 2025, we compared the \$0 base costs of power approved by the Commission in Docket No. E015/MR-19-443 to the bases used by the Company in the Fuel Adjustment Clause Calculation and found them to be in agreement.
3. We recalculated the billing adjustment charge (credit) per kWh charged to customers for purchased power for the period January 1, 2025 through December 31, 2025 as set forth in the Fuel Adjustment Clause Calculation for the Automatic Retail Fuel Adjustments and Recovery Report for each customer class listed for mathematical accuracy and found all to be calculated accurately.
4. We obtained the accounting records for the revenues billed to customers for energy delivered for the period January 1, 2025 through December 31, 2025. We compared total sales of electric energy to the Company's general ledger and found them to be in agreement.
5. For the period January 1, 2025 through December 31, 2025, we compared 16 haphazardly selected individual billings across all customer classes and compared the automatic adjustment charges and credits included in the bills to the billing adjustment charge (credit) reported by the Company in the Fuel Adjustment Clause Calculation and found them to be in agreement.



6. We compared corrections for fuel adjustment clause charges or other billing errors included within the Fuel Adjustment Clause Calculation for the period January 1, 2025 through December 31, 2025 to the Company's general ledger. No corrections or other billing errors were noted.
7. For the period January 1, 2025 through December 31, 2025, we compared the revenue reconciliations from the CIS (Customer Information System) sub-ledger to the Company's general ledger, for total revenue and found them to be in agreement. For the period January 1, 2025 through December 31, 2025, we compared the cost of power reconciliations, which includes (1) coal burned, (2) total purchase power, (3) MISO non-recoverable cost, and (4) purchased steam, to the Company's general ledger and found them to be in agreement.
8. For the period January 1, 2025 through December 31, 2025, we recalculated true ups included within the Fuel Adjustment Clause Calculation and traced the related revenue and expense amounts to the Company's accounting records. No true ups were noted.

This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants (AICPA). We were not engaged to and did not conduct an audit or an examination engagement, the objective of which would be the expression of an opinion, or a review engagement, the objective of which would be the expression of a conclusion, on Section A of Minnesota Power's Annual Report of Automatic Adjustment Changes for the period January 1, 2025 through December 31, 2025 found in Attachment No. 2 of the Company's Annual Report.. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

In performing this engagement, we are required to be independent of ALLETE, Inc. and to meet our ethical responsibilities, in accordance with the relevant ethical requirements related to our agreed-upon procedures engagement.

This report is intended solely for the information and use of Management of ALLETE, Inc. and the MPUC and is not intended to be and should not be used by anyone other than these specified parties.

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 2, 2026

2025 FAC Forecast vs. Actuals- Customer Sales

Residential:

- Residential actuals were 2% lower than the 2025 forecast.

Commercial:

- Commercial actuals were 4% lower than the 2025 forecast.

Large Power Taconite:

- Large Power Taconite actuals were 17% less than the 2025 forecast. The taconite customers ran below forecasted levels due to an iron ore industry slowdown due to poor market conditions within the steelmaking industry.

Large Power Paper and Pulp:

- Paper and Pulp actuals were 6% less than the 2025 forecast. Sofidel's Duluth mill spent a significant portion of 2025 testing their newly acquired mill's capability to produce different paper products which resulted in large fluctuations in load at their facility month-to-month and lower average load than forecasted.

Large Power Pipelines:

- Pipeline actuals were right in line with the 2025 forecast.

Other Misc.:

- Other Misc. actuals were 1% less than the 2025 forecast.

Municipals:

- Municipals came in 2% more than forecast.

Intersystem Sales:

- Please see Attachment 2.3 for the Inter System Sales Breakdown
- Overall, Intersystem Sales came in 721,724 MWhs more than forecast. Intersystem sales are removed from the Total Sales of Electricity as they are Non FAC MWh's.

**THIS DOCUMENT HAS BEEN EFILED AS A
LIVE SPREADSHEET**

2025 FAC Forecast vs. Actual- Generation Costs

Boswell:

- Boswell total costs were roughly 2% above forecast. The increase in total costs is due to Boswell 4 running higher in 2025 than what was forecasted. MP saw actual market prices come in around 20% higher than forecast and around 59% higher than 2024 which increased the output of Boswell. Boswell 4 cleared at higher levels by MISO due to the higher than forecasted market prices which increased their generation by about 10% compared to forecast. Boswell 3 had longer unplanned and planned outages throughout the year which resulted in less overall generation for 2025 by about 5%. When Boswell 3 was not on outage, the unit would have been cleared more and at higher levels due to the increase in LMPs for 2025. See Attachments 5 for an explanation of the Boswell 3 outages.

Laskin:

- Total Laskin costs were 41% higher than forecast. Laskin 1 generation was 76% more than forecast and Laskin 2 was 7% more than forecast in 2025. The biggest driver in the increase in generation was due to the increase in LMPs as discussed above. MP saw actual market prices come in around 20% higher than forecast and around 59% higher than 2024 which would have resulted in Laskin being cleared by MISO more frequently than forecasted. Also, transmission outages and drought conditions in Canada resulted in higher priced generation being dispatched in our region.

Hibbard:

- Total Hibbard costs were about 16% less than forecast due to the increase in fuel costs compared to forecast. Hibbard 3 fuel costs were 20% higher than forecast and Hibbard 4 fuel costs were 28% higher than forecast. With the increase in fuel costs compared to forecast, Hibbard would not have been cleared as often by MISO even though MP experienced higher LMPs in 2025.

Wind:

- Wind generation came in about 8% lower than forecast with Bison being 8% below forecast and Tac Ridge coming in 2% below forecast. MP saw the greatest variances between forecast to actual wind generation across North Dakota in February – April 2025 and August - December 2025 which historically are higher wind generation months. Wind generation owned by Minnesota Power has a \$0 fuel cost.

Hydro:

- MP saw lower hydro generation in 2025 by about 30% compared to forecast. Drought conditions were present throughout 2025 which lowered Minnesota Power hydro generation. Hydro generation owned by Minnesota Power has a \$0 fuel cost.

2025 Forecast vs. Actual- Purchase Costs

Manitoba Hydro:

- The MHEB contract has a variable energy piece (133 Purchase Power Agreement) and throughout 2025, MP procured less energy from Manitoba Hydro than what was forecasted specifically in May – July 2025 due to drought conditions. The MHEB fuel cost compared to forecast came in 6% above forecast due to increased LMPs in 2025 which were around 20% higher than forecast and around 59% higher than 2024.

Minnkota Power Cooperation Renewable Source:

- Costs came in 39% higher than forecast. The forecast is based on a contract. In 2024 after the 2025 forecast was filed, the MWs Minnesota Power purchases for the renewable source program increased which resulted in higher total costs in 2025.
- Purchase is offset by the sale to the renewable source customers on Attachment 1.3 “Inter-system Sales Forecast.”

Market Purchase:

- MP saw a decrease in company generation (wind and hydro) which raised the MWhs purchased from the market to cover load. Also, Boswell 3 experienced more planned and unplanned outages in 2025 which decreased Boswell 3 generation for the year. See Attachments 5 for an explanation of the Boswell 3 outages.
- The market purchase price per MWh came in 52% more than forecast due to the higher than forecasted MISO market prices in 2025 which were 20% above forecast.

Minnkota Power Station Service:

- Costs came in 16% higher than forecast. The forecast is based on prior year monthly average.

Purchase to serve Non-Firm Retail Customer

- When the forecast was prepared, there was no purchase made so the MWhs were based on customer load.
- The purchases to cover this Non-Firm Retail Customer were contracted with different counter parties and are included in the purchase by counterpart and is why actuals are showing 0 MWhs.

Counter Party Purchases:

- IMO/AEP/Shell/NextEra/HPU
- Purchases that were not known or under contract at the time of the forecast filing but were procured during times when MP was short and needed to purchase energy to cover load. This can happen when generation is lower than expected, load is high, market prices are lower than expected, or MP has generating units off for outage.
- This section also includes the purchases that were procured to serve a Non-Firm Retail Customer.

Other Purchases:

- The other purchases section includes all customer owned generation purchases that are not forecasted.

Oliver County 1:

- Oliver 1 costs came in 3% more than forecast. This higher cost was due to purchased MWhs coming in 9% higher than forecast even though the price was less than forecast by 6%. The lower price was due to credits received on the Oliver 1 invoices that were not forecasted and lowered the \$/MWh.

Oliver County 2:

- Oliver 2 costs came in less than 1% higher than forecast. Purchased MWhs came in 4% higher than forecast and the price was less than forecast by 3%. The lower price was due to credits received on the Oliver 2 invoices that were not forecasted and lowered the \$/MWh.

Wing River:

- Generation came in 65% lower than forecast and costs were 65% lower than forecast. Wing River was below forecast every month in 2025.

Nobles:

- Nobles generation came in 1% more than forecast in 2025 and the \$/MWh was in line with the 2025 forecast.

SES 20MW Solar:

- Purchased MWhs were 14% less than forecasted and the \$/MWh was 1% less than forecast. The generation and costs go through the SEA (Solar Energy Adjustment)- See Attachment 2.4- SEA

Solar Subscription Cancellations:

- We do not forecast as it is very small. Any customers that have a rolling balance of kWh due to solar garden generation is purchased back by MP when they leave the program and are paid out for their unused solar generation.

Purchase to serve Municipal Solar Energy:

- Purchase to procure solar energy for a municipal customer. Purchase is offset by the sale to the municipal customer on Attachment 2.3- Inter-system Sales

Square Butte:

- The purchase is based on generation at Square Butte. Square Butte generation was lower in 2025 compared to forecast which reduced the MWhs purchased. Fuel costs were in line with the 2025 forecast.

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Purchase Power - Coal	FY2025		FY2026		FY2027		FY2028		FY2029		FY2030		FY2031		FY2032		FY2033		FY2034	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference	Difference	% Difference
Square Butte																				
Average Cost	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74
Total Cost	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74
Total Purchase Power Coal 1	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74	\$37,046.48	\$36,974.74
Purchase Power Biomass																				
Biomass																				
Average Cost																				
Total Cost																				
Total Purchase Power Biomass 1																				
Purchase Power Hydro																				
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Total Purchase Power Diesel 1																				
Purchase Power Solar																				
Solar																				
Average Cost																				
Total Cost																				
Total Purchase Power Solar 1																				
Purchase Power Utilities																				
Utilities																				
Average Cost																				
Total Cost																				
Total Purchase Power Utilities 1																				
Total Company Purchase Power																				

2025 FAC Forecast vs. Actuals- Inter-System Sales**IPS and RFPS:**

- IPS and RFPS MWhs were lower than forecast by 15% due to Large Power customers nominating lower in 2025. The \$/MWh was higher by 31% due to higher than forecasted fuel costs with the main driver being LMPs in 2025 were 20% higher than forecast.

Economy and Non-Firm:

- Economy and Non-Firm MWhs were lower than forecast by 15% due to Paper and Pulp customers sales lower in 2025 than forecast. The \$/MWh was very similar to forecast coming in around 4% lower than forecast.

Excess Energy:

- Excess Energy is not forecasted as it is usually a small amount.

Incremental and Price Recall:

- Incremental and Price Recall is not forecasted as it is usually a small amount.

Municipal Incremental:

- Municipal Incremental MWhs were 6% lower than forecast and costs were 24% higher than forecast. The higher costs were due to higher LMPs in 2025 which were 20% higher than forecast. Also, company generation was less than forecast so more market purchases would have been allocated to Municipal Incremental sales.

Municipal Solar Energy:

- The Municipal Solar Energy sale is a direct offset of the Municipal Solar Energy purchase. See Attachment 2.2- Purchase Costs for the purchase.

Hibbing Public Utilities:

- MWhs came in slightly lower than forecast by 1% and the \$/MWh was 4% lower than forecast. The lower \$/MWh is due to the slightly lower thermal Boswell fuel costs specifically at Boswell 4. See Attachment 2.1- Generation Costs for Boswell fuel costs.

Oconto:

- Loads came in stronger than forecasted in 2025 and the \$/MWh was 3% lower than forecast due to the slightly lower thermal Boswell fuel costs specifically at Boswell 4. See Attachment 2.1- Generation Costs for Boswell fuel costs.

Minnkota Power Cooperation- Renewable Source:

- Sales side of the direct cost pass through of the “Minnkota Power Cooperation Renewable Source” listed on Attachment 2.2- Purchase Costs.

Asset Based Sales (Non MISO):

- There were no Asset Based Sales (Non MISO) forecasted in the 2025.

- Due to a decrease in large power nominations in 2025, Minnesota Power made sales to replace the loss of load (See below for an explanation of Retail Loss of Load.) Any sales that were made and not needed to cover the loss of load are either an asset-based sale if sourced from a generator or liquidation if sourced from a purchase

Minnkota Power Liquidation:

- There was less generation output and a slightly lower fuel cost at Square Butte in 2025 (See Attachment 2.2- Purchase Costs) which would decrease the MWhs and lower the costs of the Minnkota Power Liquidation sale which is based on the output and costs of Square Butte.

Liquidated Sales (Non MISO):

- There were no Liquidated Sales (Non MISO) forecasted in the 2025 forecast.
- For actuals, there were Liquidated Sales (Non MISO) as various counterparty purchases that were procured throughout the year were liquidated at times when they were not needed to serve load.
- Due to a decrease in large power nominations in 2025, Minnesota Power made sales to replace the loss of load (See below for an explanation of Retail Loss of Load.) Any sales that were made and not needed to cover the loss of load are either an asset-based sale if sourced from a generator or liquidation if sourced from a purchase.

MISO Market Sales:

- Variable- Minnesota Power uses the RTSim production cost model to determine the forecasted volume and cost for MISO market sales. When excess energy is available and it's economical, the model will sell the excess energy into the MISO market. There was more company thermal generation in 2025 (See Attachment 2.1- Generation Costs) which would increase the amount of Asset Based sales to the market.

Oliver County 1 Station Service:

- The forecast assumption used last year's average, and the current year MWhs came in slightly lower and the costs came in higher.

Oliver County 2 Station Service:

- The forecast assumption used last year's average, and the current year MWhs came in slightly lower and the costs came in higher.

WPPI Energy:

- WPPI station service is calculated when Boswell 4 is offline. Boswell 4 had one more day of outage than forecasted

MISO Costs:

- See Attachment 3 for MISO Costs breakdown and assumptions.
- MISO Costs recovered thru Customer Sales is part of their fuel cost and is reflected in the average cost price in the "Inter-System Sales- Customer Sales" section.
- MISO Costs recovered through Market Sales were more than forecast due to the increase in MISO Market sales in 2025 compared to forecast.

Sales due to Retail Loss of Load:

- No Loss of Load was anticipated when the forecast was submitted May 1, 2014. During 2025, large power customer load decreased in 2025 and sales were made to replace the lost load.

Asset Based Margins:

- The Asset Based Margin credit came in 58% more than forecast. This increase in credit is mainly due to the higher than forecasted MISO market prices, which were close to 20% higher than forecast. Higher market prices resulted in a higher sales price for Asset Bases sales. Even though company generation was lower than expected in 2025, the sales price was significantly higher which increase the Asset Based margins that are allocated to customers.

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SOLAR ENERGY ADJUSTMENT

Docket No. E015/M-15-773

	YTD 2025			January 2025			February 2025			March 2025		
	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
FUEL COST												
Total Monthly Fuel Cost	267,582,333	252,413,925	(15,168,408)	26,715,480	21,472,931	(5,242,548)	22,792,241	18,348,220	(4,444,022)	21,956,168	20,221,942	(1,734,226)
Less: Costs related to Sola	2,597,139	2,199,704	(397,436)	99,884	93,133	(6,751)	144,724	141,395	(3,329)	237,829	219,023	(18,806)
Total Non-Solar FAC Costs	264,985,194	250,214,222	(14,770,972)	26,615,596	21,379,799	(5,235,797)	22,647,517	18,206,825	(4,440,692)	21,718,339	20,002,919	(1,715,420)
Current 2-Month Total Fuel Cos	528,647,856	499,813,313	(28,834,543)	51,174,308	46,430,342	(4,743,966)	49,263,113	39,586,624	(9,676,489)	44,365,856	38,209,744	(6,156,112)
KWH SALES												
Total Monthly KWH Sales	9,055,006,000	8,242,036,843	(812,969,157)	820,138,000	789,752,403	(30,385,597)	735,809,000	696,251,219	(39,557,781)	778,382,000	725,563,931	(52,818,069)
Less: Solar Generation and Purchase	57,105,794	49,600,616	(7,505,178)	2,422,811	2,366,288	(56,523)	3,374,791	2,913,685	(461,106)	5,003,249	5,007,533	4,283
Total Non-Solar FAC KWH Sales	8,997,900,216	8,192,436,227	(805,463,989)	817,715,189	787,386,115	(30,329,074)	732,434,209	693,337,534	(39,096,675)	773,378,751	720,556,399	(52,822,352)
Current 2-Month Total KWH Sales	17,961,245,059	16,456,244,231	(1,505,000,828)	1,596,762,264	1,563,811,234	(32,951,029)	1,550,149,398	1,480,723,649	(69,425,749)	1,505,812,960	1,413,893,932	(91,919,027)
Fuel Cost - cents/kWh	2.943	3.037	0.094	3.205	2.969	(0.236)	3.178	2.673	(0.505)	2.946	2.702	(0.244)
TOGA Percentage	82.05%	151.70%	69.66%	77.85%	172.03%	94.18%	85.43%	148.38%	62.96%	66.96%	134.33%	67.36%
Fuel Cost Credit to the SEA - cents/kWh	2.415	4.607	2.193	2.895	5.108	2.212	2.715	3.966	1.251	1.973	3.630	1.657
BILLING MONTH:	YTD 2025			March 2025			April 2025			May 2025		
TIME OF GENERATION ADJUSTMENT (TOGA)												
TOGA Percentage	82.05%	151.70%	69.66%	77.85%	172.03%	94.18%	85.43%	148.38%	62.96%	66.96%	134.33%	67.36%
Less: 100 Percent	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%
Total TOGA Percentage to the FAC	-17.95%	51.70%	69.66%	-22.15%	72.03%	94.18%	-14.57%	48.38%	62.96%	-33.04%	34.33%	67.36%
TOGA to the FAC (Dollars)	\$ (277,848.99)	\$ 779,481.26	\$ 1,057,330.25	\$ (17,197.19)	\$ 50,604.80	\$ 67,801.99	\$ (15,628.54)	\$ 37,682.79	\$ 53,311.33	\$ (48,694.58)	\$ 46,445.97	\$ 95,140.55
SOLAR COSTS												
Costs Related to Sola	\$ 2,597,139.31	\$ 2,199,703.55	(\$397,435.76)	\$ 99,883.68	\$ 93,132.52	(\$6,751.16)	\$ 144,724.11	\$ 141,394.63	(\$3,329.48)	\$ 237,829.31	\$ 219,023.07	(\$18,806.24)
Less: Credit from FAC / TOGA	\$ 1,387,346.64	\$ 2,242,108.78	\$854,762.13	\$ 60,453.91	\$ 120,859.89	\$60,405.98	\$ 91,622.31	\$ 115,565.59	\$23,943.27	\$ 98,701.14	\$ 181,749.50	\$83,048.36
Net Costs Related to Sola	\$ 1,209,792.67	(\$42,405.23)	(\$1,252,197.90)	\$ 39,429.77	(\$27,727.37)	(\$67,157.14)	\$ 53,101.79	\$ 25,829.04	(\$27,272.75)	\$ 139,128.17	\$ 37,273.57	(\$101,854.60)
Current 2-Month Net Costs Related to Sola	\$ 2,406,252.46	(\$1,975.07)	(\$2,468,227.53)	\$ 54,680.76	(\$15,942.40)	(\$70,623.16)	\$ 92,531.56	(\$1,898.33)	(\$94,429.89)	\$ 192,229.96	\$ 63,102.61	(\$129,127.35)
KWH SALES												
Total Monthly KWh Sales	9,057,602,000	8,245,049,529	(812,552,471)	820,400,000	790,059,533	(30,340,467)	736,063,000	696,570,613	(39,492,387)	778,620,000	725,853,073	(52,766,927)
Less: Retail SES Exempt	4,741,723,602	3,970,503,470	(771,220,132)	407,588,550	381,635,573	(25,952,977)	367,267,550	303,462,642	(63,804,908)	402,333,550	352,418,388	(49,915,162)
Less: Municipal SES Exempt	1,378,882,000	1,406,168,268	27,286,268	127,112,000	125,173,203	(1,938,797)	110,365,000	114,565,062	4,200,062	116,661,000	117,691,508	1,030,508
Total Non-Exempt KWh Sales	2,936,996,398	2,868,377,791	(68,618,607)	285,699,450	283,250,757	(2,448,693)	258,430,450	278,542,909	20,112,459	259,625,450	255,743,177	(3,882,273)
Current 2-Month Total Non-Exempt KWh Sa	5,875,259,519	5,734,191,797	(141,067,722)	569,830,623	528,688,085	(41,142,538)	544,129,900	561,793,666	17,663,766	518,055,900	534,286,086	16,230,186
SEA ADJUSTMENT												
SEA Adjustment - Dollars per KWH	\$ 0.0041	(\$0.0001)	(\$0.0042)	\$ 0.0010	(\$0.0003)	(\$0.0013)	\$ 0.0017	(\$0.0000)	(\$0.0017)	\$ 0.0037	\$ 0.0012	(\$0.0025)
SEA Adjustment - cents per KWH	\$ 0.04096	(\$0.00108)	(\$0.04204)	\$ 0.00960	(\$0.00302)	(\$0.01281)	\$ 0.01701	(\$0.00034)	(\$0.01734)	\$ 0.03711	\$ 0.01181	(\$0.02530)
BILLING MONTH:	YTD 2025			March 2025			April 2025			May 2025		

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April 2025			May 2025			June 2025			July 2025			August 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
20,135,170	18,717,141	(1,418,029)	20,627,861	18,310,022	(2,317,839)	19,411,486	20,018,812	607,326	22,766,045	21,556,505	(1,209,540)	23,890,558	15,926,361	(7,964,197)
264,663	239,216	(25,447)	299,098	314,202	15,104	316,155	236,965	(79,190)	356,554	275,597	(80,957)	311,361	221,681	(89,680)
19,870,507	18,477,925	(1,392,582)	20,328,762	17,995,819	(2,332,943)	19,095,331	19,781,847	686,516	22,409,491	21,280,907	(1,128,584)	23,579,197	15,704,680	(7,874,517)
41,588,846	38,480,845	(3,108,001)	40,199,269	36,473,745	(3,725,525)	39,424,093	37,777,666	(1,646,427)	41,504,822	41,062,754	(442,067)	45,988,688	36,985,587	(9,003,101)
715,291,000	648,551,471	(66,739,529)	737,683,000	666,580,114	(71,102,886)	713,914,000	650,454,879	(63,459,121)	756,049,000	691,430,398	(64,618,602)	751,454,000	696,060,997	(55,393,003)
5,727,253	5,419,642	(307,611)	6,470,314	6,846,613	376,299	6,756,185	5,228,292	(1,527,893)	7,542,654	6,033,313	(1,509,341)	6,674,511	5,059,005	(1,615,506)
709,563,747	643,131,829	(66,431,918)	731,212,686	659,733,501	(71,479,185)	707,157,815	645,226,587	(61,931,228)	748,506,346	685,397,085	(63,109,261)	744,779,489	691,001,991	(53,777,497)
1,482,942,498	1,363,688,227	(119,254,270)	1,440,776,433	1,302,865,330	(137,911,103)	1,438,370,501	1,304,960,088	(133,410,413)	1,455,664,161	1,330,623,672	(125,040,489)	1,493,285,835	1,376,399,076	(116,886,759)
2,804	2,822	0.018	2,790	2,800	0.010	2,741	2,895	0.154	2,851	3,086	0.235	3,080	2,687	(0.393)
74.90%	132.72%	57.82%	94.74%	138.23%	43.49%	82.16%	162.54%	80.38%	86.02%	200.63%	114.61%	94.05%	187.03%	92.98%
2.100	3.745	1.645	2.643	3.870	1.227	2.252	4.706	2.454	2.452	6.191	3.739	2.897	5.025	2.129
June 2025			July 2025			August 2025			September 2025			October 2025		
April 2025			May 2025			June 2025			July 2025			August 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
74.90%	132.72%	57.82%	94.74%	138.23%	43.49%	82.16%	162.54%	80.38%	86.02%	200.63%	114.61%	94.05%	187.03%	92.98%
100.00%	100.00%		100.00%	100.00%		100.00%	100.00%		100.00%	100.00%		100.00%	100.00%	
-25.10%	32.72%	57.82%	-5.26%	38.23%	43.49%	-17.84%	62.54%	80.38%	-13.98%	100.63%	114.61%	-5.95%	87.03%	92.98%
\$ (40,308.92)	\$50,043.15	\$90,352.07	\$ (9,494.72)	\$73,287.29	\$82,782.01	\$ (33,038.89)	\$94,664.30	\$127,703.19	\$ (30,062.53)	\$187,361.12	\$217,423.65	\$ (12,226.32)	\$118,304.76	\$130,531.08
April 2025			May 2025			June 2025			July 2025			August 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
\$ 264,663.06	\$239,216.10	(\$25,446.96)	\$ 299,098.38	\$314,202.25	\$15,103.88	\$ 316,155.31	\$236,965.31	(\$79,190.00)	\$ 356,553.75	\$275,597.14	(\$80,956.61)	\$ 311,360.97	\$221,680.80	(\$89,680.17)
\$ 120,283.25	\$202,985.45	\$82,702.20	\$ 171,027.05	\$264,992.46	\$93,965.41	\$ 152,148.14	\$246,023.35	\$93,875.20	\$ 184,978.53	\$373,549.15	\$188,570.62	\$ 193,348.63	\$254,240.22	\$60,891.60
\$144,379.81	\$36,230.65	(\$108,149.17)	\$128,071.32	\$49,209.79	(\$78,861.53)	\$164,007.17	(\$9,058.04)	(\$173,065.21)	\$171,575.22	(\$97,952.01)	(\$269,527.23)	\$118,012.34	(\$32,559.42)	(\$150,571.76)
\$ 283,507.98	\$73,504.22	(\$210,003.77)	\$ 272,451.14	\$85,440.44	(\$187,010.70)	\$ 292,078.49	\$40,151.76	(\$251,926.74)	\$ 335,582.39	(\$107,010.04)	(\$442,592.43)	\$ 289,587.56	(\$130,511.43)	(\$420,098.99)
April 2025			May 2025			June 2025			July 2025			August 2025		
715,517,000	648,796,516	(66,720,484)	737,895,000	666,798,995	(71,096,005)	714,099,000	650,652,549	(63,446,451)	756,250,000	691,647,250	(64,602,750)	751,666,000	696,298,470	(55,367,530)
377,503,550	299,944,562	(77,558,988)	400,940,550	338,269,235	(62,671,315)	386,742,550	328,859,349	(57,883,201)	401,554,550	339,553,098	(62,001,452)	397,256,550	331,642,738	(65,613,812)
110,929,000	115,448,244	4,519,244	113,877,000	111,886,471	(1,990,529)	107,716,000	108,622,444	906,444	109,512,000	121,196,623	11,684,623	111,537,000	119,751,533	8,214,533
227,084,450	233,403,710	6,319,260	223,077,450	216,643,289	(6,434,161)	219,640,450	213,170,756	(6,469,694)	245,183,450	230,897,529	(14,285,921)	242,872,450	244,904,198	2,031,748
486,709,900	489,146,887	2,436,987	450,161,900	450,046,999	(114,901)	442,717,900	429,814,044	(12,903,855)	464,823,900	444,068,285	(20,755,615)	488,055,900	475,801,727	(12,254,173)
\$0.00058	\$0.00015	(\$0.00043)	\$0.00061	\$0.00019	(\$0.00042)	\$0.00066	\$0.00009	(\$0.00057)	\$0.00072	(\$0.00024)	(\$0.00096)	\$0.00059	(\$0.00027)	(\$0.00087)
\$0.05825	\$0.01503	(\$0.04322)	\$0.06052	\$0.01898	(\$0.04154)	\$0.06597	\$0.00934	(\$0.05663)	\$0.07220	(\$0.02410)	(\$0.09629)	\$0.05933	(\$0.02743)	(\$0.08676)
June 2025			July 2025			August 2025			September 2025			October 2025		

September 2025			October 2025			November 2025			December 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
21,398,610	24,074,522	2,675,913	20,756,647	23,581,788	2,825,142	21,183,658	24,469,809	3,286,151	25,948,410	25,715,871	(232,539)
238,953	185,096	(53,857)	157,483	141,210	(16,274)	103,268	81,989	(21,279)	67,167	50,198	(16,969)
21,159,657	23,889,427	2,729,770	20,599,164	23,440,579	2,841,415	21,080,390	24,387,821	3,307,430	25,881,243	25,665,673	(215,570)
44,738,854	39,594,107	(5,144,747)	41,758,821	47,330,006	5,571,185	41,679,554	47,828,400	6,148,846	46,961,633	50,053,494	3,091,861
726,385,000	662,738,567	(63,646,433)	740,053,000	653,842,965	(86,210,035)	764,511,000	654,707,847	(109,803,153)	815,337,000	706,102,054	(109,234,946)
5,170,030	4,203,186	(966,844)	3,854,421	3,407,370	(447,051)	2,375,013	2,066,980	(308,033)	1,734,552	1,048,711	(685,841)
721,214,970	659,535,381	(62,679,589)	736,198,579	650,435,956	(85,762,624)	762,135,987	652,640,867	(109,495,120)	813,602,448	705,053,342	(108,549,106)
1,465,994,458	1,349,537,373	(116,457,086)	1,457,413,549	1,308,970,977	(148,442,573)	1,498,334,567	1,303,076,462	(195,258,104)	1,575,738,435	1,357,694,210	(218,044,225)
3,052	2,934	(0,118)	2,865	3,616	0,751	2,782	3,670	0,888	2,980	3,687	0,707
81.54%	147.58%	66.04%	84.95%	122.32%	37.37%	81.32%	116.25%	34.93%	74.64%	158.40%	83.76%
2.489	4.330	1.841	2.434	4.423	1.989	2.262	4.267	2.004	2.224	5.840	3.616
November 2025			December 2025			January 2026			February 2026		
September 2025			October 2025			November 2025			December 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
81.54%	147.58%	66.04%	84.95%	122.32%	37.37%	81.32%	116.25%	34.93%	74.64%	158.40%	83.76%
100.00%	100.00%		100.00%	100.00%		100.00%	100.00%		100.00%	100.00%	
-18.46%	47.58%	66.04%	-15.05%	22.32%	37.37%	-18.68%	16.25%	34.93%	-25.36%	58.40%	83.76%
\$ (29,130.26)	\$58,673.29	\$87,803.54	\$ (16,617.48)	\$27,501.65	\$44,119.13	\$ (12,342.98)	\$12,329.62	\$24,672.60	\$ (13,106.58)	\$22,582.52	\$35,689.10
September 2025			October 2025			November 2025			December 2025		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
\$ 238,952.55	\$185,095.50	(\$53,857.05)	\$ 157,483.30	\$141,209.60	(\$16,273.70)	\$ 103,267.95	\$81,988.54	(\$21,279.41)	\$ 67,166.95	\$50,198.09	(\$16,968.86)
\$ 128,659.05	\$181,994.75	\$53,335.70	\$ 93,811.67	\$150,712.15	\$56,900.47	\$ 53,729.87	\$88,187.77	\$34,457.90	\$ 38,583.08	\$61,248.50	\$22,665.43
\$110,293.50	\$3,100.75	(\$107,192.75)	\$63,671.62	(\$9,502.55)	(\$73,174.17)	\$49,538.08	(\$6,199.23)	(\$55,737.31)	\$28,583.87	(\$11,050.41)	(\$39,634.28)
\$ 228,305.84	(\$29,458.68)	(\$257,764.52)	\$ 173,965.12	(\$6,401.80)	(\$180,366.92)	\$ 113,209.70	(\$15,701.77)	(\$128,911.48)	\$ 78,121.95	(\$17,249.64)	(\$95,371.59)
September 2025			October 2025			November 2025			December 2025		
726,590,000	662,980,634	(63,609,366)	740,234,000	654,065,799	(86,168,201)	764,700,000	654,942,910	(109,757,090)	815,568,000	706,383,188	(109,184,812)
385,024,550	321,636,400	(63,388,150)	399,293,550	320,834,482	(78,459,068)	407,495,550	320,386,047	(87,109,504)	408,722,550	331,860,955	(76,861,595)
112,708,000	112,060,176	(647,824)	116,146,000	116,946,725	800,725	118,338,000	116,305,159	(2,032,841)	123,981,000	126,521,120	2,540,120
228,857,450	229,284,057	426,608	224,794,450	216,284,592	(8,509,858)	238,866,450	218,251,705	(20,614,745)	282,864,450	248,001,113	(34,863,337)
471,729,900	474,188,256	2,458,356	453,651,900	445,588,649	(8,063,250)	463,660,900	434,536,296	(29,124,603)	521,730,900	466,252,817	(55,478,082)
\$0,000.48	(\$0,000.06)	(\$0,000.55)	\$0,000.38	(\$0,000.01)	(\$0,000.40)	\$0,006.24	(\$0,000.4)	(\$0,006.28)	\$0,006.15	(\$0,006.4)	(\$0,006.19)
\$0,048.40	(\$0,006.21)	(\$0,054.61)	\$0,038.35	(\$0,001.44)	(\$0,039.75)	\$0,024.42	(\$0,003.61)	(\$0,028.03)	\$0,014.97	(\$0,003.70)	(\$0,015.67)
November 2025			December 2025			January 2026			February 2026		

Attachment 3
Minnesota Power's
Monthly MISO Day 2 Charges and Allocation
Docket No. E999/AA-07-1130

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	January 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		662,213			125,173				413,891	
Energy Charges	(3,772,455.28)	1,843,944	-		351,227	-	2,195,171.32		(5,967,626.61)	
Market Administration Charges	204,504.20	134,241	-		26,177	-	160,417.58		44,086.62	
Congestion and Loss Charges	4,335,066.39	3,825,725	(931,396)		728,710	(177,409)	3,445,630.40		889,435.99	
FTRs and ARRs	(331,432.28)	732,910	(955,633)		139,602	(182,025)	(265,145.82)		(66,286.46)	
RSG and Make Whole Payments	7,484.04	36,481	(31,452)		6,949	(5,991)	5,987.23		1,496.81	
RNU Charges	441,005.90	296,356	-		56,449	-	352,804.72		88,201.18	
ASM Charge Types	168,780.36	359,012	(244,603)		68,383	(46,591)	136,201.25		32,579.11	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	(124,859.85)	30,881	(114,787)		5,882	(21,864)	(99,887.88)		(24,971.97)	
Total	928,093.48	662,213	7,259,551	(2,277,871)	125,173	1,383,379	(433,880)	5,931,179	413,891	(5,003,085)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	February 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		578,772			114,565				329,537	
Energy Charges	(5,219,156.17)	1,196,805	-		245,129	-	1,441,933.84		(6,661,090.01)	
Market Administration Charges	213,392.80	141,900	-		29,384	-	171,283.72		42,109.08	
Congestion and Loss Charges	2,806,439.52	2,146,428	(257,605)		439,630	(52,763)	2,275,689.93		530,749.59	
FTRs and ARRs	(358,673.84)	713,132	(954,269)		146,063	(195,453)	(290,525.81)		(68,148.03)	
RSG and Make Whole Payments	206,611.67	145,140	(6,235)		29,728	(1,277)	167,355.45		39,256.22	
RNU Charges	22,447.63	15,092	-		3,091	-	18,182.58		4,265.05	
ASM Charge Types	(18,302.51)	179,985	(189,792)		36,864	(38,873)	(11,816.27)		(6,486.24)	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	117,000.23	78,659	-		16,111	-	94,770.19		22,230.04	
Total	(2,230,240.67)	578,772	4,617,141	(1,407,902)	114,565	946,000	(288,365)	3,866,874	329,537	(6,097,114)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	March 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		602,865			117,692				393,169	
Energy Charges	(2,122,031.49)	546,639	-		104,122	-	650,760.98		(2,772,792.47)	
Market Administration Charges	195,640.07	122,601	-		23,790	-	146,391.30		49,248.77	
Congestion and Loss Charges	3,101,897.04	2,272,184	(282,230)		432,797	(53,758)	2,368,993.45		732,903.58	
FTRs and ARRs	(294,507.46)	551,737	(739,751)		105,093	(140,905)	(223,825.67)		(70,681.79)	
RSG and Make Whole Payments	(6,408.36)	19,835	(23,926)		3,778	(4,557)	(4,870.35)		(1,538.01)	
RNU Charges	307,952.47	196,597	-		37,447	-	234,043.88		73,908.59	
ASM Charge Types	11.10	157,882	(150,944)		30,073	(28,751)	8,260.04		(8,248.94)	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	111,293.14	73,362	(2,313)		13,974	(441)	84,582.79		26,710.35	
Total	1,293,846.51	3,940,838	(1,199,163)	117,692	751,073	(228,412)	3,264,336	393,169	(1,970,490)	

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	April 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		527,684			115,448				368,310	
Energy Charges	794,517.09	1,497,696	-		328,763	-	1,826,458.53		(1,031,941.44)	
Market Administration Charges	201,287.58	126,159	-		27,898	-	154,057.89		47,229.69	
Congestion and Loss Charges	3,280,460.14	2,358,020	(283,346)		517,614	(62,198)	2,530,090.03		750,370.11	
FTRs and ARRs	(389,330.69)	524,940	(770,763)		115,231	(169,192)	(299,784.63)		(89,546.06)	
RSG and Make Whole Payments	(7,128.67)	21,499	(26,000)		4,719	(5,707)	(5,489.08)		(1,639.59)	
RNU Charges	181,651.32	114,695	-		25,177	-	139,871.52		41,779.80	
ASM Charge Types	73,152.21	204,415	(150,283)		44,872	(32,989)	66,015.16		7,137.05	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	118,497.92	75,381	(562)		16,547	(123)	91,243.40		27,254.52	
Total	4,253,106.90	4,922,805	(1,230,954)	115,448	1,080,821	(270,209)	4,502,463	368,310	(249,356)	

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	May 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		547,847			111,886				459,830	
Energy Charges	(4,035,041.27)	1,272,368	-		260,605	-	1,532,973.40		(5,568,014.66)	
Market Administration Charges	124,867.55	77,382	-		16,133	-	93,514.99		31,352.56	
Congestion and Loss Charges	2,190,771.85	1,478,762	(102,061)		302,879	(20,904)	1,658,675.99		532,095.86	
FTRs and ARRs	(221,137.55)	505,781	(645,275)		103,594	(132,165)	(168,064.54)		(53,073.01)	
RSG and Make Whole Payments	9,152.67	16,645	(10,872)		3,409	(2,227)	6,956.03		2,196.64	
RNU Charges	328,235.74	207,051	-		42,408	-	249,459.16		78,776.58	
ASM Charge Types	42,016.26	173,904	(141,765)		35,619	(29,036)	38,721.16		3,295.10	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	25,048.74	17,801	(2,000)		3,646	(410)	19,037.04		6,011.70	
Total	(1,536,086.01)	547,847	3,749,695	(901,973)	111,886	768,293	(184,741)	3,431,273	459,830	(4,967,359)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	June 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		536,604			108,622				389,441	
Energy Charges	(4,302,903.70)	830,705	-	170,144	-	-	1,000,849.96		(5,303,753.65)	
Market Administration Charges	106,969.57	66,515	-	13,820	-	-	80,335.93		26,633.64	
Congestion and Loss Charges	4,478,559.36	3,107,027	(285,851)	636,379	(58,548)	-	3,399,007.41		1,079,551.94	
FTRs and ARRs	(617,260.03)	539,875	(929,243)	110,577	(190,327)	-	(469,117.62)		(148,142.41)	
RSG and Make Whole Payments	(178,353.75)	56,512	(169,017)	11,575	(34,618)	-	(135,548.85)		(42,804.90)	
RNU Charges	345,237.89	217,776	-	44,605	-	-	262,380.80		82,857.09	
ASM Charge Types	(16,708.11)	226,753	(235,508)	46,443	(48,236)	-	(10,547.94)		(6,160.17)	
Grandfathered Charge Types	-	-	-	-	-	-	-		-	
Miscellaneous Charges	91,899.35	59,499	(1,529)	12,186	(313)	-	69,843.51		22,055.84	
Total	(92,559.42)	536,604	5,104,662	(1,621,147)	108,622	1,045,730	(332,042)	4,197,203	389,441	(4,289,763)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	July 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		564,200			121,197				410,747	
Energy Charges	(1,743,747.31)	876,053	-		192,304	-	1,068,357.79		(2,812,105.10)	
Market Administration Charges	157,137.69	99,006	-		22,062	-	121,067.86		36,069.83	
Congestion and Loss Charges	2,261,707.82	2,137,311	(678,635)		469,166	(148,969)	1,778,873.24		482,834.59	
FTRs and ARRs	(209,914.35)	544,829	(679,090)		119,597	(149,069)	(163,733.19)		(46,181.16)	
RSG and Make Whole Payments	61,110.81	56,858	(17,771)		12,481	(3,901)	47,666.43		13,444.38	
RNU Charges	268,394.44	171,665	-		37,683	-	209,347.66		59,046.78	
ASM Charge Types	272,199.36	604,358	(429,548)		132,664	(94,291)	213,183.19		59,016.17	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	48,570.61	56,409	(25,343)		12,382	(5,563)	37,885.08		10,685.53	
Total	1,115,459.07	564,200	4,546,489	(1,830,388)	121,197	998,339	(401,792)	3,312,648	410,747	(2,197,189)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	August 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		571,250			119,752				340,241	
Energy Charges	4,542,286.08	2,644,079	-		541,558	-	3,185,637.59		1,356,648.49	
Market Administration Charges	160,371.54	106,220	-		22,083	-	128,302.96		32,068.58	
Congestion and Loss Charges	(5,422,643.05)	870,091	(4,503,902)		178,211	(922,486)	(4,378,086.47)		(1,044,556.58)	
FTRs and ARRs	(500,981.93)	677,953	(1,014,764)		138,858	(207,843)	(405,795.36)		(95,186.57)	
RSG and Make Whole Payments	13,994.22	28,611	(19,203)		5,860	(3,933)	11,335.32		2,658.90	
RNU Charges	493,925.46	332,066	-		68,014	-	400,079.62		93,845.84	
ASM Charge Types	268,122.48	445,447	(264,502)		91,236	(54,175)	218,006.14		50,116.34	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	34,524.70	28,470	(5,259)		5,831	(1,077)	27,965.01		6,559.69	
Total	(410,400.50)	571,250	5,132,937	(5,807,630)	119,752	1,051,652	(1,189,514)	(812,555)	340,241	402,155

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	September 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		546,475			112,060				238,433	
Energy Charges	5,668,578.84	3,407,093	-		697,838	-	4,104,930.73		1,563,648.11	
Market Administration Charges	163,325.22	106,999	-		22,212	-	129,211.28		34,113.94	
Congestion and Loss Charges	3,050,970.84	2,481,319	(448,367)		508,222	(91,834)	2,449,339.62		601,631.22	
FTRs and ARRs	497,882.01	991,919	(661,325)		203,164	(135,452)	398,305.61		99,576.40	
RSG and Make Whole Payments	15,151.62	28,413	(18,353)		5,820	(3,759)	12,121.30		3,030.32	
RNU Charges	307,080.24	203,901	-		41,763	-	245,664.19		61,416.05	
ASM Charge Types	82,727.68	191,392	(136,059)		39,201	(27,868)	66,665.47		16,062.21	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	72,001.74	47,809	-		9,792	-	57,601.39		14,400.35	
Total	9,857,718.19	546,475	7,458,845	(1,264,104)	112,060	1,528,012	(258,913)	7,463,840	238,433	2,393,879

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	October 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		533,489			116,947				268,417	
Energy Charges	1,853,252.82	1,883,740	-		413,504	-	2,297,243.96		(443,991.15)	
Market Administration Charges	162,018.55	99,989	-		22,164	-	122,152.82		39,865.73	
Congestion and Loss Charges	4,924,092.71	4,104,562	(1,030,611)		901,001	(226,232)	3,748,720.53		1,175,372.18	
FTRs and ARRs	1,036,908.25	1,262,636	(616,435)		277,164	(135,315)	788,050.27		248,857.98	
RSG and Make Whole Payments	(12,685.55)	18,523	(26,429)		4,066	(5,801)	(9,641.02)		(3,044.53)	
RNU Charges	441,498.15	275,142	-		60,397	-	335,538.59		105,959.56	
ASM Charge Types	178,228.83	260,469	(149,075)		57,176	(32,724)	135,846.15		42,382.68	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	54,391.66	34,932	(1,035)		7,668	(227)	41,337.66		13,054.00	
Total	8,637,705.42	7,939,993	(1,823,585)	116,947	1,743,141	(400,299)	7,459,249	268,417	1,178,456	

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	November 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		536,336			116,305				345,363	
Energy Charges	(313,670.74)	1,706,267	-		374,546	-	2,080,812.93		(2,394,483.68)	
Market Administration Charges	161,845.67	97,224	-		21,558	-	118,781.40		43,064.27	
Congestion and Loss Charges	6,468,961.19	4,433,696	(501,254)		973,250	(110,031)	4,795,661.44		1,673,299.75	
FTRs and ARRs	491,322.92	892,878	(594,743)		195,998	(130,553)	363,578.96		127,743.96	
RSG and Make Whole Payments	8,358.91	18,755	(13,682)		4,117	(3,003)	6,185.59		2,173.32	
RNU Charges	300,864.79	182,565	-		40,075	-	222,639.94		78,224.85	
ASM Charge Types	53,686.70	165,425	(131,688)		36,313	(28,907)	41,142.75		12,543.95	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	37,235.43	25,805	(3,211)		5,665	(705)	27,554.22		9,681.21	
Total	7,208,604.87	7,522,613	(1,244,578)	116,305	1,651,521	(273,200)	7,656,357	345,363	(447,752)	

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	December 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Mwh	Cost/(Revenue)
		578,532			126,521				469,679	
Energy Charges	(5,055,115.99)	1,829,563	-		401,611	-	2,231,174.49		(7,286,290.49)	
Market Administration Charges	161,565.17	100,582	-		22,393	-	122,974.98		38,590.19	
Congestion and Loss Charges	9,704,083.97	6,837,896	(721,537)		1,501,002	(158,386)	7,458,975.17		2,245,108.81	
FTRs and ARRs	(3,537,127.27)	633,825	(2,867,167)		139,132	(629,378)	(2,723,588.00)		(813,539.27)	
RSG and Make Whole Payments	57,597.43	61,441	(25,074)		13,487	(5,504)	44,350.02		13,247.41	
RNU Charges	610,298.17	385,342	-		84,587	-	469,929.59		140,368.58	
ASM Charge Types	63,688.95	158,793	(117,954)		34,857	(25,892)	49,803.35		13,885.60	
Grandfathered Charge Types	-	-	-		-	-	-		-	
Miscellaneous Charges	86,849.86	57,559	(2,722)		12,635	(598)	66,874.39		19,975.47	
Total	2,091,840.29	578,532	10,065,002	(3,734,454)	126,521	2,209,705	(819,758)	7,720,494	469,679	(5,628,654)

MINNESOTA POWER

MISO MONTHLY ALLOCATION

	January - December 2025	FPE Retail			FAC Resale			Subtotal FPE and FAC	Other	
		Mwh	Cost	Revenue	Mwh	Cost	Revenue	Cost/(Revenue)	Cost/(Revenue)	
Energy Charges	(13,705,487.13)	6,786,267	19,534,952.44	-	1,406,168	4,081,353.10	-	23,616,305.54	4,427,058	(37,321,792.66)
Market Administration Charges	2,012,925.61		1,278,817.89	-		269,674.81	-	1,548,492.70		464,432.91
Congestion Charges	41,180,367.79		36,053,022.14	(10,026,795.39)		7,588,861.20	(2,083,517.21)	31,531,570.74		9,648,797.04
FTRs and ARR	(4,434,252.22)		8,572,415.93	(11,428,456.91)		1,794,071.78	(2,397,676.62)	(3,459,645.81)		(974,606.41)
RSG and Make Whole Payments	174,885.04		508,713.50	(388,014.34)		105,988.35	(80,279.42)	146,408.08		28,476.96
RNU Charges	4,048,592.20		2,598,247.29	-		541,694.97	-	3,139,942.26		908,649.94
ASM Charge Types	1,167,603.31		3,127,834.42	(2,341,720.96)		653,700.91	(488,333.95)	951,480.43		216,122.88
Grandfathered Charge Types	-		-	-		-	-	-		-
Miscellaneous Charges	672,453.53		586,568.18	(158,760.55)		122,319.80	(31,320.64)	518,806.79		153,646.74
Grand Total	31,117,088.13	6,786,267	72,260,572	(24,343,748)	1,406,168	15,157,665	(5,081,128)	57,993,361	4,427,058	(26,876,273)

MINNESOTA POWER
MSO MONTHLY ALLOCATION

	YTD 2025			Jan-25			Feb-25			Mar-25			Apr-25			May-25			Jun-25			Jul-25			Aug-25			Sep-25			Oct-25			Nov-25			Dec-25								
	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual	Difference									
Energy Charges	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)	117,755,487.13	117,755,487.13	(0.00)						
Market Administration Charges	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00	1,971,850.00	2,010,850.00	39,000.00			
Congestion and Loss Charges	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)	41,252,758.66	41,150,357.79	(102,390.87)			
File and MISC	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)	8,983,454.35	8,434,252.23	(549,202.12)			
RIS and Make Whole Payments	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04	1,176,000.00	1,748,850.04	572,850.04
Risk Charge	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25	2,558,000.00	4,468,382.25	1,910,382.25			
ADM Charge Types	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31	216,000.00	1,187,633.31	971,633.31			
Grandfathered Charge Types	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53	660,000.00	672,453.53	12,453.53			
Miscellaneous Charge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					
Grand Total	41,176,164.32	31,117,088.13	(10,059,076.19)	5,988,488.81	328,053.48	(4,660,435.33)	4,987,348.63	(2,210,248.67)	(7,037,597.04)	3,247,858.10	1,293,848.81	(1,953,843.99)	3,284,832.77	4,263,158.96	988,274.13	2,280,658.21	(1,636,088.91)	(3,786,142.32)	1,784,362.62	(92,559.42)	(1,886,822.04)	2,427,446.18	1,118,459.67	(1,211,881.12)	3,482,038.48	(419,489.86)	(3,882,438.96)	1,927,599.35	8,827,118.18	7,868,118.84	2,674,835.18	8,637,705.42	5,843,079.24	3,368,130.87	7,208,604.87	3,848,473.96	6,017,406.38	2,891,848.28	(3,825,866.10)						

Attachment 4
Treatment of Auction Revenue Rights (ARRs)
Docket No. E015/M-05-277

Minnesota Power’s Self Scheduled FTRs from the Annual Allocation:

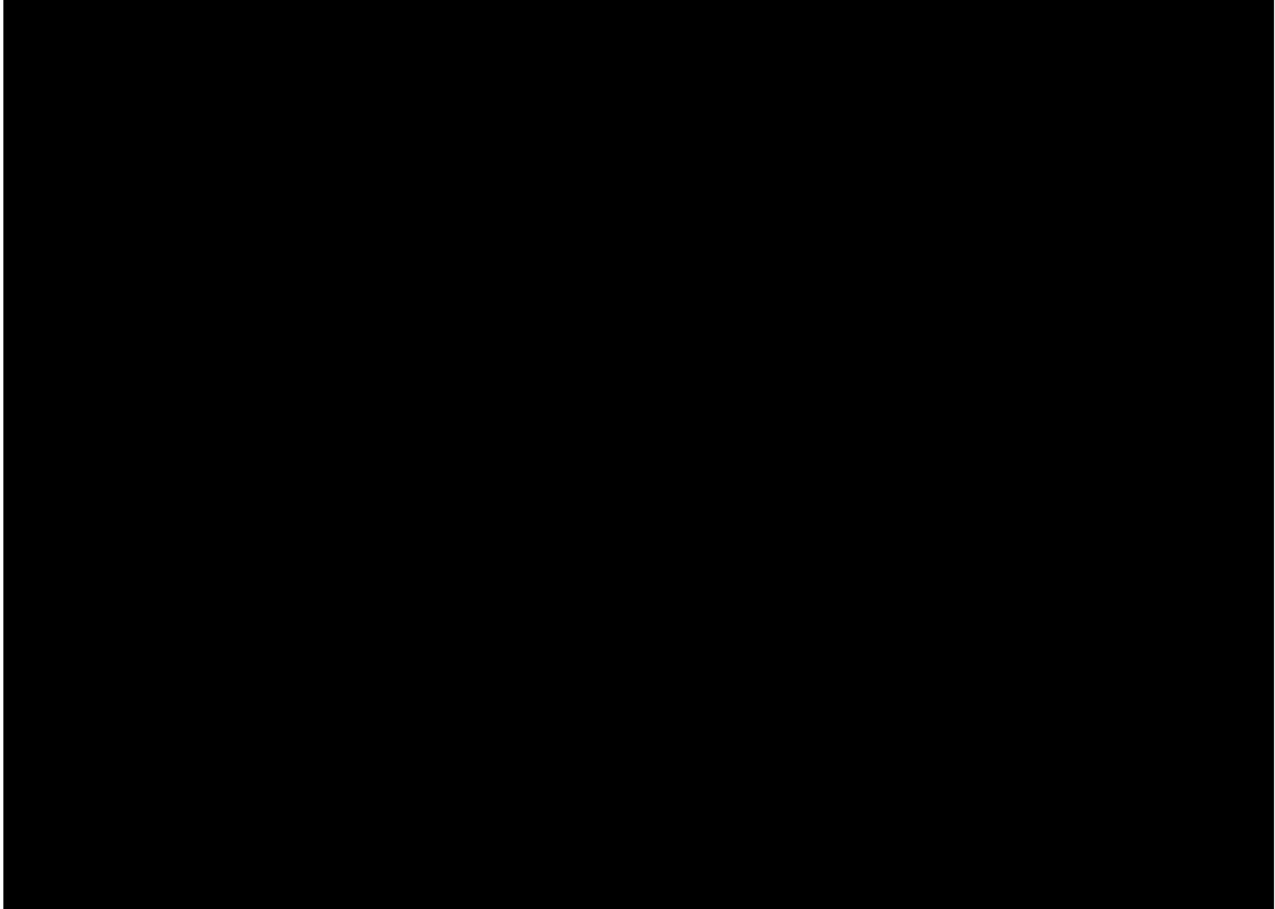
Source	Sink	Winter 24/25		Spring 2025		Summer 2025		Fall 2025		Winter 25/26	
		Peak	Off -peak	Peak	Off -peak	Peak	Off -peak	Peak	Off -peak	Peak	Off -peak
[TRADE SECRET DATA BEGINS]											
[TRADE SECRET DATA ENDS]											

Minnesota Power’s FTRs purchased in the Monthly Auction for the requested time period:

Monthly FTR Purchases						
Source	Sink	Class Period	Month	Awarded FTRs	Clearing (\$/MW-Month)	Total Monthly Cost
[TRADE SECRET DATA BEGINS]						
[TRADE SECRET DATA ENDS]						

Minnesota Power’s FTRs purchased in the Annual Auction for the requested time period:

Annual FTR Purchases						
Source	Sink	Class Period	Season	Awarded FTRs	Clearing (\$/MW-Season)	Total Seasonal Cost
[TRADE SECRET DATA BEGINS						



TRADE SECRET DATA ENDS]

Minnesota Power’s Total ARR/FTR revenues and costs for the requested time period:

Total ARR / FTR Revenues and Costs		
	Cost to hold FTRS	Revenue Generated from ARR/FTRs
Jan-25	983,571.85	(1,772,387.24)
Feb-25	1,046,815.88	(1,415,291.46)
Mar-25	862,692.98	(1,102,699.43)
Apr-25	831,510.95	(1,230,828.98)
May-25	799,337.55	(1,036,741.20)
Jun-25	852,990.46	(1,446,793.30)
Jul-25	853,807.24	(1,042,263.35)
Aug-25	956,062.84	(1,440,236.50)
Sep-25	1,059,223.99	(414,294.59)
Oct-25	1,345,471.75	(688,976.15)
Nov-25	1,233,129.69	(1,367,680.60)
Dec-25	804,269.70	(3,523,261.04)

Below is monthly detail of different MISO charge type costs included in the ARR/FTR Revenue and Cost Table. Charge types labeled “Cost” are included in the Cost to Hold FTRs calculation and charge types labeled “Revenue” are included in the Revenues Generated from ARRs/FTRs calculation.

Note: Charges/Credits are shown in the month in which they were recorded in Account 55500 of the General Ledger and included in the FAC recovery.

Charge Type		Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Financial Transmission Rights Market Administration Amount	Cost	4,743.20	2,326.40	3,599.28	1,473.60	2,187.60	1,531.68	2,344.24	2,379.12	2,180.64	1,571.76	1,620.00	2,269.20	28,226.72
Auction Revenue Rights Transaction Amount	Revenue	(662,683.62)	(662,683.62)	(387,233.65)	(387,233.65)	(387,233.65)	(727,444.35)	(727,444.35)	(727,444.35)	(594,273.59)	(594,273.59)	(594,273.59)	(473,910.42)	(6,926,132.43)
Financial Transmission Rights Annual Transaction Amount	Cost	634,360.30	634,360.30	765,273.12	765,273.12	765,273.12	850,433.52	850,433.52	850,433.52	1,024,089.38	1,024,089.38	1,024,089.38	641,249.08	9,829,357.74
Auction Revenue Rights Infeasible Uplift Amount	Cost	24,531.62	24,531.62	32,084.16	31,876.83	31,876.83	1,025.26	1,029.48	1,033.75	16,919.21	16,918.35	16,918.35	14,823.02	213,568.48
Auction Revenue Rights Stage 2 Distribution Amount	Revenue	(390,772.73)	(390,772.73)	(224,895.68)	(224,896.06)	(224,896.15)	(274,432.84)	(274,433.15)	(274,433.76)	(321,338.75)	(321,338.74)	(321,338.74)	(244,485.91)	(3,488,035.24)
Financial Transmission Rights Full Funding Guarantee Amount	Revenue	(21,981.52)	-	-	-	-	-	-	(23,601.74)	-	(22,558.59)	(12,086.58)	(217,419.56)	(297,647.99)
FTR Guarantee Uplift Amount	Revenue	19,609.20	-	-	-	-	-	-	16,930.24	-	23,907.08	17,871.13	217,419.56	295,737.21
Financial Transmission Rights Monthly Transaction Amount	Cost	319,936.73	385,597.56	61,736.42	32,887.40	-	-	-	102,216.45	16,034.76	302,892.26	190,501.96	145,928.40	1,557,731.94
Financial Transmission Rights Hourly Allocation Amount	Revenue	(687,308.91)	(358,369.78)	(481,784.69)	(598,485.96)	(411,401.30)	(432,873.10)	(31,871.80)	(391,353.29)	511,492.33	277,643.21	(433,056.13)	(2,804,864.71)	(5,842,234.13)
Financial Transmission Rights Monthly Allocation Amount	Revenue	(29,249.66)	(3,465.33)	(8,785.41)	(20,213.31)	(13,210.10)	(12,043.01)	(8,514.05)	(40,333.60)	(10,174.58)	(52,355.52)	(24,796.69)	-	(223,141.26)
Financial Transmission Rights Transaction Amount	Cost	-	-	-	-	-	-	-	-	-	-	-	-	-
Financial Transmission Rights Yearly Allocation Amount	Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
Costs of hold FTRs		983,571.85	1,046,815.88	862,692.98	831,510.95	799,337.55	852,990.46	853,807.24	956,062.84	1,059,223.99	1,345,471.75	1,233,129.69	804,269.70	11,628,884.88
Revenue Generated from ARR/FTRs		(1,772,387.24)	(1,415,291.46)	(1,102,699.43)	(1,230,828.98)	(1,036,741.20)	(1,446,793.30)	(1,042,263.35)	(1,440,236.50)	(414,294.59)	(688,976.15)	(1,367,680.60)	(3,523,261.04)	(16,481,453.84)

**Attachment 5
Plant Outages:
Identification of Forced Outages, Lessons Learned and
Mechanism for Information Sharing
Docket No. E999/AA-10-884
Plant Outage Contingency Plans
Docket No. E999/AA-08-995**

Apr-25			May-25			Jun-25			Jul-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
350	350		350	350		350	350		350	350	
2.0	2.3	0.3	2.0	5.5	3.5	2.0	4.6	2.6	2.0	5.6	3.6
13,365	16,811	3,446	13,811	45,987	32,176	13,365	35,627	22,262	13,811	47,245	33,434
8,115	5,121	(2,994)	10,404	15,698	5,294	13,365	12,507	(858)	13,811	10,045	
\$664.23	\$48,656.57	\$47,992.34	\$43,296.79	\$193,845.28	\$150,548.49	\$3,407.90	\$171,183.34	\$167,775.44	\$107,059.02	\$144,617.98	\$37,558.96
7.0	10.3	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58,800	42,610	(16,190)	0	0	0	0	0	0	0	0	0
35,702	16,344	(19,358)	0	0	0	0	0	0	0	0	0
\$2,922.31	(\$41,815.14)	(\$44,737.45)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$3,586.53	\$6,841.43	\$3,254.90	\$43,296.79	\$193,845.28	\$150,548.49	\$3,407.90	\$171,183.34	\$167,775.44	\$107,059.02	\$144,617.98	\$37,558.96

Apr-25			May-25			Jun-25			Jul-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
464	464		464	464		464	464		464	464	
1.0	1.1	0.1	1.0	1.0	(0.0)	1.0	0.0	(1.0)	1.0	0.0	(1.0)
13,860	11,671	(2,189)	14,322	5,785	(8,537)	13,860	0	(13,860)	14,322	0	(14,322)
8,416	4,759	(3,657)	10,789	259	(10,530)	13,860	0	(13,860)	14,322	0	
(\$9,162.47)	\$19,432.61	\$28,595.09	\$30,310.55	(\$3,640.22)	(\$33,950.77)	(\$10,451.04)	\$0.00	\$10,451.04	\$96,405.11	\$0.00	(\$96,405.11)
4.0	4.0	(0.0)	17.0	5.0	(12.0)	0.0	0.0	0.0	0.0	0.0	0.0
44,544	30,486	(14,058)	189,312	50,971	(138,341)	0	0	0	0	0	0
27,046	9,732	(17,314)	142,616	17,293	(125,323)	0	0	0	0	0	0
(\$29,446.84)	\$45,072.33	\$74,519.17	\$400,652.89	\$210,593.34	(\$190,059.55)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(\$38,609.31)	\$64,504.95	\$103,114.25	\$430,963.44	\$206,953.11	(\$224,010.33)	(\$10,451.04)	\$0.00	\$10,451.04	\$96,405.11	\$0.00	(\$96,405.11)

Apr-25			May-25			Jun-25			Jul-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
(\$35,022.77)	\$71,346.38	\$106,369.15	\$474,260.23	\$400,798.40	(\$73,461.83)	(\$7,043.15)	\$171,183.34	\$178,226.48	\$203,464.14	\$144,617.98	(\$58,846.15)

Aug-25			Sep-25			Oct-25			Nov-25			Dec-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
350	350		350	350		350	350		350	350		350	350	
2.0	3.5	1.5	2.0	6.1	4.1	2.0	0.0	(2.0)	2.0	6.5	4.5	2.0	4.4	2.4
13,811	28,960	15,149	13,365	49,084	35,719	13,811	0	(13,811)	13,365	54,472	41,107	13,811	37,100	23,289
13,811	12,451	(1,360)	8,236	23,587	15,351	8,540	0	(8,540)	13,365	12,796	(569)	10,488	10,286	(202)
TRADE SECRET DATA ENDS														
\$115,675.14	\$167,759.18	\$52,084.05	\$75,343.48	\$389,187.25	\$313,843.78	\$38,023.58	\$0.00	(\$38,023.58)	\$93,777.26	\$855,527.78	\$761,750.52	\$175,619.14	\$464,153.23	\$288,534.09
0.0	0.0	0.0	0.0	0.0	0.0	7.0	15.6	8.6	0.0	0.0	0.0	0.0	0.0	0.0
0	0	0	0	0	0	58,800	126,910	68,110	0	0	0	0	0	0
0	0	0	0	0	0	36,359	19,281	(17,078)	0	0	0	0	0	0
TRADE SECRET DATA ENDS														
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$161,884.49	\$529,998.63	\$368,114.14	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
TRADE SECRET DATA ENDS														
\$115,675.14	\$167,759.18	\$52,084.05	\$75,343.48	\$389,187.25	\$313,843.78	\$199,908.08	\$529,998.63	\$330,090.55	\$93,777.26	\$855,527.78	\$761,750.52	\$175,619.14	\$464,153.23	\$288,534.09

Aug-25			Sep-25			Oct-25			Nov-25			Dec-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
464	464		464	464		464	464		464	464		464	464	
1.0	5.6	4.6	1.0	0.0	(1.0)	1.0	3.2	2.2	1.0	0.0	(1.0)	1.0	4.1	3.1
14,322	60,207	45,885	13,860	0	(13,860)	14,322	35,140	20,818	13,860	0	(13,860)	14,322	45,417	31,095
14,322	34,451	20,129	8,541	0	(8,541)	8,856	7,616	(1,240)	13,860	0	(13,860)	10,876	12,735	1,859
TRADE SECRET DATA ENDS														
\$106,482.63	\$736,114.13	\$629,631.49	\$67,438.82	\$0.00	(\$67,438.82)	\$28,509.00	\$355,213.70	\$326,704.70	\$83,017.16	\$0.00	(\$83,017.16)	\$172,762.53	\$652,472.06	\$479,709.52
0.0	0.0	0.0	7.0	9.0	2.0	0.0	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0
0	0	0	77,952	99,916	21,964	0	6,793	6,793	0	0	0	0	0	0
0	0	0	48,034	33,638	(14,396)	0	938	938	0	0	0	0	0	0
TRADE SECRET DATA ENDS														
\$0.00	\$0.00	\$0.00	\$379,292.27	\$986,839.93	\$607,547.66	\$0.00	\$21,542.80	\$21,542.80	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
TRADE SECRET DATA ENDS														
\$106,482.63	\$736,114.13	\$629,631.49	\$446,731.09	\$986,839.93	\$540,108.84	\$28,509.00	\$376,756.50	\$348,247.49	\$83,017.16	\$0.00	(\$83,017.16)	\$172,762.53	\$652,472.06	\$479,709.52

Aug-25			Sep-25			Oct-25			Nov-25			Dec-25		
Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)	Forecast	Actual	Difference: Over/(Under)
\$222,157.77	\$903,873.31	\$681,715.54	\$522,074.57	\$1,376,027.18	\$853,952.62	\$228,417.08	\$906,755.13	\$678,338.05	\$176,794.42	\$855,527.78	\$678,733.36	\$348,381.67	\$1,116,625.29	\$768,243.61

Supplement to Attachment 5 – 2025 Unplanned Outages

Boswell Unit 3 Bottom Ash System Pluggage

Outage Date: 1/6/2025-1/15/2025

Equipment or Condition that Resulted in the Outage

U3 bottom ash hoppers bridged due to ash and coal slag buildup, preventing ash removal from the boiler. The bridging increased rapidly, exceeding hopper quenching capacity. Lack of quenching caused upper layers to turn into molten slag, which evaporated seal water and overflowed into operation areas. To prevent severe equipment damage and unsafe conditions, the unit was taken offline. Contributing factors included high sustained market demand, ambient conditions, coal quality, and multiple mechanical failures in the ash removal system. Contract support was required to remove ash and slag, involving 7 days of continuous labor. Bottom ash hoppers and ash removal systems were inspected, and repairs/replacements were completed prior to restart including seal trough repair, bottom ash spray repair, 3-1 conveyor chain replacement, 3-2/3-3 conveyor scraper repairs, bottom ash grinder repairs, and soot blower inspections/repairs.

Description of Equipment Failure (including identified root cause)

The primary cause was multiple failures on 3-1 conveyor chain, leading to hopper overfilling and bridging. Chain failures were due to erosion beyond tolerable limits. Each break caused extended downtime of the bottom ash system, allowing ash accumulation and bridging. Once bridging occurred, ash removal system could no longer pull the ash out of the hopper system, resulting in molten slag which ran out of the boiler.

Actions to Prevent Reoccurrence

- Developed a conveyor chain maintenance metric based on total distance chain has traveled, rather than OEM hours-based runtime. This approach better reflects wear under unit-specific conditions and enables proactive replacement before failure.
- Revised operational procedures to reduce allowable duration of non-removal of bottom ash from a maximum of 36 out of 48 hours down to 24 out of 36 hours before requiring the unit shutdown for bottom ash repair and removal.

Change in Energy

\$620,380

Number 3 and 4 Turbine Bearing Inspection

Outage Date: 11/25/2025-12/4/2025

Equipment or Condition that Resulted in the Outage

A maintenance outage was scheduled to inspect turbine bearings #3 and #4 after operating data indicated likely damage. Inspection confirmed that both bearings had experienced damage. Temporary modifications allowed the unit to return to service while replacement bearings are planned for a future outage.

Description of Equipment Failure (including identified root cause)

In mid-2025, Boswell Energy Center Unit 3 experienced unexpected increases in operating temperatures on turbine bearing #4. The turbine experienced a loss of oil suction pressure when the turning gear oil pump was shut off per standard procedure for that portion of the unit start-up. As designed, low oil pressure was sensed and tripped the turbine and lube oil pumps were automatically started, but this momentary loss of lubrication caused initial damage to the #4 bearing. Post incident review found the motor suction pump did not run as intended during this portion of the start-up and was the main factor for the loss of oil suction pressure.

After the unit restart during the planned fall outage, the #3 bearing temperature increased. The unit was not able to reach full load and was derated due to the high bearing temperature. This event was similar to the #4 bearing identified in mid-2025, however, the unit was still able to reach full load prior to the #3 Bearing event. Post incident review and engineering assessment determined that #3 bearing damage was the result of a combination of the #4 Bearing already being damaged and Lube Oil Setpoint which was set too high at slow speeds.

Actions to Prevent Reoccurrence

The incident investigation continues, however Minnesota Power implemented the following immediate corrective measures while continuing to focus on additional long-term reliability improvements.

Completed Actions:

- An alarm has been put in place to alert operators that the motor suction pump is not running during startup.
- The procedure for startup and shutdown has been modified to control lube oil temperature at 90°F whenever the unit is on turning gear.

Change in Energy

* \$1,144,571

Attachment 6
Minnesota Power's
Annual Ancillary Services, Market Charges and
Summary
January 2024 through December 2024

Table 6-A: Summary of ASM Charge Types

	1st Quarter 2025				2nd Quarter 2025				3rd Quarter 2025				4th Quarter 2025				2025 Total
	Jan-25	Feb-25	Mar-25	Total	Apr-25	May-25	Jun-25	Total	Jul-25	Aug-25	Sep-25	Total	Oct-25	Nov-25	Dec-25	Total	
Day Ahead Regulation Amount	(96,822.66)	(99,400.20)	(164,375.25)	\$ (362,598.11)	(140,015.50)	(138,058.11)	(134,637.86)	\$ (412,711.47)	(72,262.26)	(71,650.09)	(81,953.39)	\$ (225,865.74)	(57,755.53)	(52,571.26)	(20,373.01)	\$ (130,699.80)	
Real Time Regulation Amount	(17,746.03)	(2,734.23)	57,267.65	\$ 36,787.39	68,894.91	48,399.36	34,990.14	\$ 152,284.41	13,611.69	8,095.30	20,335.65	\$ 42,042.64	(22,742.93)	(39,708.54)	(30,681.86)	\$ (93,133.33)	
Regulation Cost Distribution Amount	59,285.68	51,807.72	60,404.83	\$ 171,498.23	65,300.16	67,671.58	52,464.58	\$ 185,436.32	45,468.96	62,961.08	63,509.00	\$ 171,939.04	102,641.66	104,563.96	83,977.82	\$ 291,183.44	
Regulation SubTotal	\$ (67,283.01)	\$ (50,326.71)	\$ (46,702.97)	\$ (164,312.69)	\$ (6,320.43)	\$ (21,987.17)	\$ (47,183.14)	\$ (74,990.74)	\$ (13,183.61)	\$ (63,717.71)	\$ 1,891.26	\$ (11,866.06)	\$ 22,143.20	\$ 12,284.06	\$ 32,922.95	\$ 67,350.21	
Day Ahead Spinning Reserve Amount	(42,283.37)	(57,322.89)	(64,743.70)	\$ (164,349.96)	(47,262.81)	(57,579.39)	(82,107.71)	\$ (186,949.91)	(108,593.31)	(45,587.37)	(58,967.41)	\$ (213,148.09)	(47,222.34)	(56,653.68)	(90,787.22)	\$ (194,663.24)	
Real Time Spinning Reserve Amount	(13,079.98)	12,276.75	1,788.39	\$ 985.16	(11,485.67)	(4,985.37)	14,451.18	\$ (2,019.86)	84,062.33	13,197.47	55,276.26	\$ 152,536.06	6,815.31	(4,210.24)	11,341.32	\$ 13,946.39	
Spinning Reserve Cost Distribution Amount	34,684.28	35,719.81	44,324.96	\$ 114,729.05	43,375.63	46,850.80	35,923.26	\$ 126,149.69	36,072.38	25,178.74	33,931.67	\$ 95,182.79	43,915.46	45,109.94	36,989.70	\$ 125,015.10	
Spinning Reserve SubTotal	\$ (20,679.07)	\$ (9,326.33)	\$ (18,638.35)	\$ (48,635.70)	\$ (15,372.85)	\$ (15,713.96)	\$ (31,733.27)	\$ (62,820.98)	\$ 11,541.40	\$ (7,211.16)	\$ 30,240.82	\$ 34,870.76	\$ 3,598.43	\$ (15,753.98)	\$ (42,456.20)	\$ (64,701.75)	
Day Ahead Supplemental Reserve Amount	(2,098.26)	(8,393.55)	-	\$ (10,491.81)	-	(26.39)	(2,509.32)	\$ (2,535.71)	(11,903.32)	(6,489.72)	(24,574.87)	\$ (42,967.91)	(12,440.56)	-	(1,257.31)	\$ (13,697.87)	
Real Time Supplemental Reserve Amount	1,279.07	4,707.87	(23.71)	\$ 5,963.23	(3.44)	(0.07)	(11,445.94)	\$ (11,449.45)	488.72	1,922.06	28,491.40	\$ 30,902.18	3,136.85	(4.16)	304.00	\$ 3,436.69	
Supplemental Reserve Cost Distribution Amount	4,572.16	5,669.57	4,757.12	\$ 14,998.85	8,350.34	5,481.57	7,188.78	\$ 21,020.69	21,068.07	14,327.58	20,288.47	\$ 55,684.12	14,741.13	6,399.48	4,368.20	\$ 25,508.81	
Supplemental Reserve SubTotal	\$ 3,752.97	\$ 1,983.89	\$ 4,733.41	\$ 10,470.27	\$ 8,346.90	\$ 5,455.11	\$ (6,766.48)	\$ 7,035.53	\$ 9,653.47	\$ 9,759.92	\$ 24,285.00	\$ 43,618.39	\$ 5,437.42	\$ 6,395.32	\$ 3,414.89	\$ 15,247.63	
Contingency Reserve Deployment Failure Charge Amount	45.04	37.80	-	\$ 82.84	-	-	524.11	\$ 524.11	-	-	263.59	\$ 263.59	-	-	-	\$ -	
Real Time Excessive Deficient Energy Deployment Charge Amount	61,159.59	44,545.31	60,542.10	\$ 166,247.00	35,212.47	46,867.91	82,193.47	\$ 164,273.85	38,093.83	30,556.73	27,764.72	\$ 96,415.28	31,099.76	34,423.38	22,146.31	\$ 88,669.45	
Net Regulation Adjustment Amount	6,655.45	2,939.26	5,814.73	\$ 15,409.44	3,011.62	805.20	933.48	\$ 4,750.30	340.94	454.33	2,431.96	\$ 3,227.23	(340.26)	(736.43)	(901.29)	\$ (1,977.98)	
Other Charge SubTotal	\$ 67,860.08	\$ 47,523.37	\$ 66,356.83	\$ 181,739.28	\$ 38,224.09	\$ 47,673.11	\$ 83,651.06	\$ 169,548.26	\$ 38,434.77	\$ 31,011.06	\$ 30,460.27	\$ 99,906.10	\$ 30,759.50	\$ 33,686.95	\$ 21,245.02	\$ 85,691.47	
Total	\$ (6,349.03)	\$ (10,146.78)	\$ 5,756.92	\$ (10,738.89)	\$ 25,377.71	\$ 15,427.09	\$ (2,031.83)	\$ 38,772.97	\$ 46,446.63	\$ 32,986.11	\$ 86,797.65	\$ 166,229.19	\$ 61,848.55	\$ 36,612.35	\$ 15,126.66	\$ 113,587.56	

Table 6-B: Summary of MWh of ASM products Purchased and Supplier

	1st Quarter 2025				2nd Quarter 2025				3rd Quarter 2025				4th Quarter 2025				2025 Total
	Jan-25	Feb-25	Mar-25	Total	Apr-25	May-25	Jun-25	Total	Jul-25	Aug-25	Sep-25	Total	Oct-25	Nov-25	Dec-25	Total	
Total MISO Reg Procured (MWh)	460,016.20	415,373.04	459,724.50	1,335,113.74	444,964.28	459,969.47	256,963.40	1,161,897.15	570,360.35	555,164.71	579,325.31	1,704,850.37	602,981.06	585,385.20	522,033.68	1,710,399.94	
MP Share of Reg Procured by MISO	6,957.64	6,113.91	7,921.98	20,993.53	7,068.91	7,088.42	3,226.08	17,381.41	7,158.10	7,536.48	8,115.08	22,809.66	9,156.72	9,150.29	7,938.45	28,245.46	
MP Supplied Reg Volume	7,265.30	7,477.00	10,847.30	25,589.60	8,427.10	9,123.10	3,577.30	21,127.50	6,038.90	6,061.40	5,896.90	17,997.20	3,520.80	2,780.30	2,061.10	8,362.20	
MP Net Buyer or (Seller) of Regulation	(307.66)	(1,363.09)	(2,925.32)	(4,596.07)	(1,360.19)	(2,034.68)	(351.22)	(3,746.09)	1,119.20	1,475.08	2,278.18	4,872.46	5,635.92	6,369.99	5,877.35	17,883.26	
Total MISO Spin Procured (MWh)	709,705.58	632,718.95	692,371.68	2,034,796.21	664,146.26	687,463.45	333,551.06	1,685,160.77	744,060.84	736,517.34	686,456.97	2,167,035.15	698,233.28	668,302.88	686,840.42	2,053,376.58	
MP Share of Spin Procured by MISO	10,723.10	9,301.85	11,940.27	31,965.22	10,560.34	10,609.88	4,166.87	25,337.09	9,328.49	10,023.74	9,710.05	29,062.28	10,618.56	10,450.15	10,444.40	31,513.11	
MP Supplied Spin Volume	11,745.20	12,271.70	15,687.20	39,704.10	9,601.20	12,858.10	20,787.90	43,247.20	25,200.90	14,837.40	13,812.00	53,850.30	11,142.10	12,557.60	23,389.00	47,088.70	
MP Net Buyer or (Seller) of Spinning Reserves	(1,022.10)	(2,969.85)	(3,746.93)	(7,738.88)	959.14	(2,248.22)	(16,621.03)	(17,910.11)	(15,872.41)	(4,813.66)	(4,101.95)	(24,788.02)	(623.54)	(2,107.45)	(12,944.60)	(15,575.59)	
Total MISO Supp Procured (MWh)	805,562.38	734,732.85	822,843.43	2,363,138.66	799,293.91	825,618.50	347,381.79	1,972,294.20	768,400.75	778,565.46	780,037.84	2,327,004.05	818,016.32	798,338.61	824,595.41	2,440,950.34	
MP Share of Supp Procured by MISO	12,216.29	10,843.98	14,202.51	37,262.78	12,709.32	12,735.63	4,597.65	29,842.60	9,659.50	10,548.98	11,047.54	31,255.92	12,456.33	12,485.13	12,550.09	37,491.55	
MP Supplied Supp Volume	656.20	1,216.90	-	1,873.10	-	-	551.50	551.50	1,225.60	1,000.30	1,827.50	4,053.40	1,201.00	-	293.70	1,494.70	
MP Net Buyer or (Seller) of Supplemental Reserves	11,560.09	9,627.08	14,202.51	35,389.68	12,709.32	12,735.63	3,846.35	29,291.30	8,433.90	9,548.58	9,220.04	27,202.52	11,255.33	12,485.13	12,256.39	35,996.85	

Negative numbers indicate a payment from MISO
Positive numbers indicate a charge from MISO

Table 6-C: Comparison of MISO Schedule 17 Rates and Amounts before and after the start of the ASM Mark

Monthly Average Schedule 17	Amount	Rate per MWh
April 2005 through December 2008	\$ 140,922.50	\$ 0.07223
January 2025 through December 2025	\$ 165,391.73	\$ 0.08729
Average Monthly Increase	\$ 24,469.23	\$ 0.01506

Table 6-E: Contingency Reserve Deployment Events

Date	Day of Week	Node	Contingency Reserve Deployment Failure Charge Amount	HE	Shortfall MW	Event MW Provided	Event MW Requested
6/1/2025	Sunday	MP.HIBBAR3	\$ 524.11	19	3.4	11.2	14.6
9/24/2025	Wednesday	MP.HIBBAR3	\$ 263.59	14	3.1	4.7	7.8
2/15/2025	Saturday	MP.HIBBAR4	\$ 37.80	23	1.4	15.0	16.4
1/25/2025	Saturday	MP.HIBBAR4	\$ 45.04	17	1.8	8.4	10.2
Total			\$ 870.54		9.7		\$ 89.75

**Attachment 7
Wind Curtailment Reporting**

Oliver I and II

Docket No. E015/M-05-975

Bison Wind Energy

Docket No. E015/M-11-234

Docket No. E015/M-11-626

Nobles 2 Wind Energy

Docket No. E015/M-18-545

Minnesota Power
 Wind Energy Purchase Agreement with FPL
 Docket No. E015/M-05-975
 Dated December 20, 2005

Oliver County I				
	FPL Wind Energy in FAC (MWh)	Curtailments of Wind Energy MWh	Curtailment Payments by MP	Reason Codes
	[TRADE SECRET DATA BEGINS			
January 2025				2
February 2025				2
March 2025				2
April 2025				2
May 2025				2
June 2025				2
July 2025				2
August 2025				2
September 2025				2
October 2025				2
November 2025				2
December 2025				2
Total				

TRADE SECRET DATA ENDS]

1. Minnesota Power’s refusal to accept Contract Energy at the Point of Delivery as a result of low load conditions that justify not accepting Contract Energy; or
2. The availability of less expensive energy from another source; or
3. Minnesota Power’s election to use non-firm transmission services to deliver Contract Energy.

Minnesota PowerWind Energy Purchase
 Agreement with FPL Docket No. E015/
 M-05-975
 Dated December 20, 2005

Oliver County II			
FPL Wind Energy in FAC (MWh)	Curtailements of Wind Energy MWh	Curtailement Payments by MP	Reason Codes
[TRADE SECRET DATA BEGINS]			
January 2025			2
February 2025			2
March 2025			2
April 2025			2
May 2025			2
June 2025			2
July 2025			2
August 2025			2
September 2025			2
October 2025			2
November 2025			2
December 2025			2
Total			
[TRADE SECRET DATA ENDS]			

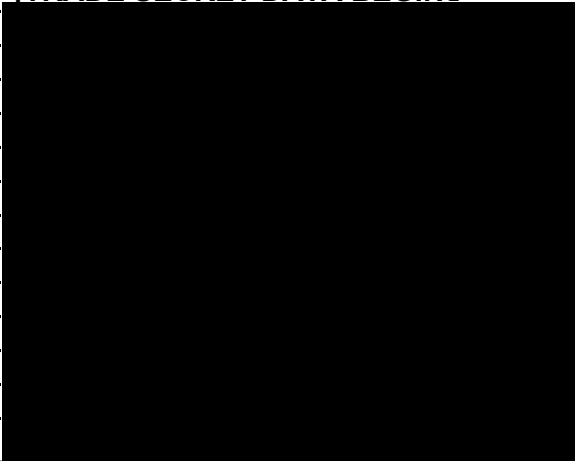
1. Minnesota Power’s refusal to accept Contract Energy at the Point of Delivery as a result of low load conditions that justify not accepting Contract Energy; or
2. The availability of less expensive energy from another source; or
3. Minnesota Power’s election to use non-firm transmission services to deliver Contract Energy.

Minnesota Power
Bison Wind Energy Curtailment Reporting
Docket No. E015/M-09-285; Dated
Docket No. E015/M-11-234; Dated September 8, 2011
Docket No. E015/M-11-626; November 2, 2011

Bison	
Delivered MWh	Lost MWh

[TRADE SECRET DATA BEGINS

January 2025
February 2025
March 2025
April 2025
May 2025
June 2025
July 2025
August 2025
September 2025
October 2025
November 2025
December 2025
Total

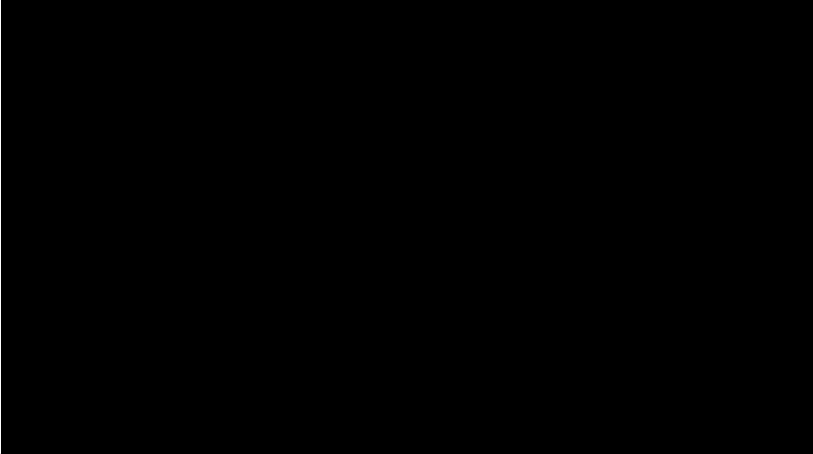


TRADE SECRET DATA ENDS]

Minnesota Power
Wind Energy Purchase Agreement with Nobles 2
Docket No. E015/M-18-545
Dated January 23, 2019

Nobles 2		
Nobles Wind Energy in FAC (MWh)	Curtailments of Wind Energy MWh	Curtailment Payments by MP

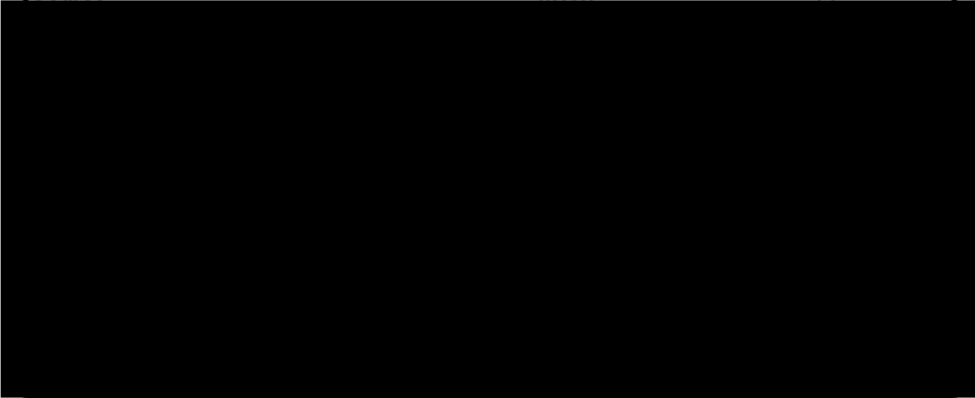
[TRADE SECRET DATA BEGINS

January 2025		
February 2025		
March 2025		
April 2025		
May 2025		
June 2025		
July 2025		
August 2025		
September 2025		
October 2025		
November 2025		
December 2025		
Total		

TRADE SECRET DATA ENDS]

**Attachment 8
Offsetting Revenues and/or Compensation
Received by Investor-Owned Utilities (IOUs)
Docket No. E999/AA-10-884**

Minnesota Power's Offsetting Revenues
For the Reporting Period of January 1, 2025 through December 31, 2025

[TRADE SECRET DATA BEGINS]		
Source	MWh	<u>Offsetting Revenues</u> /1
		
[TRADE SECRET DATA ENDS]		

/1 The costs associated with the Contract MWh used to support the sales shown above were included in the "Less Fuel Costs Recovered through Inter System Sales" line in the Fuel Clause calculation. The revenues associated with all purchased power contracts except for Wing River, Oliver County I, and Oliver County II, are for the sale of purchases that were no longer needed to cover load. The margins from these sales were passed through to the ratepayers in the Fuel Clause.

Attachment 9
Generation Facilities Maintenance Expense
Docket No. E999/AA-06-1208, dated February 6, 2008

Minnesota Power
AAA Compliance Filing
Summary of Generation Maintenance Expenses

	FERC Acct	Final Rates	
		Test Year 2024 Docket No. E015/GR-23-155 [1]	2025 Actual Expenses [2]
<u>Steam Power Generation Maintenance</u>			
Maintenance Supervision and Engineering	510	\$3,345,196	\$3,382,549
Maintenance of Structures	511	\$564,519	\$999,865
Maintenance of Boiler Plant	512	\$11,201,851	\$12,363,189
Maintenance of Electric Plant	513	\$1,910,524	\$2,797,880
Maintenance of Misc. Steam Plant	514	\$2,863,860	\$4,533,563
Sub-Total Steam Power		\$19,885,950	\$24,077,046
<u>Hydraulic Power Generation Maintenance</u>			
Maintenance Supervision and Engineering	541	\$375,188	\$193,761
Maintenance of Structures	542	\$12,076	\$27,116
Maintenance of Reservoirs, Dams and Waterways	543	\$1,182,237	\$1,000,920
Maintenance of Electric Plant	544	\$905,705	\$891,517
Maintenance of Misc. Hydraulic Plant	545	\$1,265,144	\$1,052,180
Sub-Total Hydraulic Power		\$3,740,350	\$3,165,494
<u>Other Power Generation [3]</u>			
Maintenance of Computer Hardware, Software, and Equip	553	\$11,665,405	\$55,844
Maintenance of Misc. Other Pwr Generation	554	\$3,142,290	\$220,076
Sub-Total Other Power Generation		\$14,807,695	\$275,920
<u>Other Power Supply Expenses (Solar and Wind)</u>			
Maintenance of Wind and Solar Panels, Structures, Equip and Plant [3]	558	n/a	\$3,797,234
		\$0	\$3,797,234
TOTAL		\$38,433,995	\$31,315,694

[1] Docket E015/GR-23-155

[2] 2025 report run 01/25/2026 by Accounting

[3] Reflects new FERC accounts in 2025 per FERC Oder 898

**Minnesota Power
Docket GR-23-155
FINAL 2024 General Rates**

<u>Utility Operating Expense</u> Operations & Maintenance Exp.	<u>FERC</u> <u>Acct No.</u>	<u>Total Company</u> <u>Approved 2024</u> <u>Cost of</u> <u>Service Model</u>	<u>MN Jurisdiction</u> <u>Approved 2024</u> <u>Cost of</u> <u>Service Model</u>
Steam Production Demand			
Supervision & Engineering	500	\$6,501,221	\$5,708,843
Steam Expenses	502	\$5,411,982	\$4,752,362
Steam Expense - Envir/Ash Systems	502.1	\$8,852,113	\$7,773,204
Electric Expenses	505	\$1,611,363	\$1,414,968
Miscellaneous	506	\$686,830	\$603,118
Allowences	509	\$10,763,360	\$9,451,506
Maint. Structures	511	\$564,519	\$495,715
Misc Maint Plant	514	\$2,863,860	\$2,514,809
Total Demand Steam Production		\$37,255,248	\$32,714,524
Steam Production Energy:			
Maint. Supervision & Engineering	510	\$3,345,196	\$2,937,479
Maint. Boiler Plant	512	\$5,007,423	\$4,397,111
Maint. Boiler Plant - Outage	512.01	\$4,399,960	\$3,863,686
Maint. Boiler Plant - Envir/Ash Systems	512.1	\$1,794,468	\$1,575,756
Main. Electric Plant	513	\$1,645,444	\$1,444,895
Main. Electric Plant - Outage	513.01	\$265,080	\$232,772
Total Steam Energy		\$16,457,571	\$14,451,698
Total Steam - Compliance Schedule 7 - Line 13		\$53,712,819	\$47,166,222

<u>Utility Operating Expense</u>	FERC	Total Company	MN Jurisdiction
Operations & Maintenance Exp.	<u>Acct No.</u>	Approved 2024	Approved 2024
		Cost of	Cost of
		<u>Service Model</u>	<u>Service Model</u>
Hydro Production:			
Demand			
Operations Supervision & Engineering	535	\$1,021,792	\$889,532
Hydraulic Expenses	537	\$936,982	\$815,700
Miscellaneous	539	\$62,009	\$53,983
Maintenance Supervision & Engineering	541	\$375,188	\$326,624
Maint. Structures	542	\$12,076	\$10,513
Total Demand Hydro		\$2,408,047	\$2,096,352
Energy			
Maintenance of Reservoirs, Dams, and Waterways	543	\$1,182,237	\$1,029,209
Electric Plant	544	\$905,705	\$788,471
Maintenance of Misc Hydro Plant	545	\$1,030,236	\$896,883
Maintenance of Rec Facilities	545.2	\$234,908	\$204,502
Total Energy Hydro		\$3,353,086	\$2,919,066
Total Hydro - Compliance Schedule 7 - Line 14		\$5,761,133	\$5,015,418
Other Power Generation (Wind Production)			
Operation & Engineering	546	\$636,286	\$564,080
Generation Expenses	548	\$208,000	\$184,396
Misc. Other Power Generation Expenses	549	\$1,419,369	\$1,258,299
Rents	550	\$3,425,847	\$3,037,082
Maintenance of Generating and Electric Plant	553	\$11,665,405	\$10,341,615
Maintenance of Misc. Other Power Generation Plt.	554	\$3,142,290	\$2,785,703
Total Wind - Compliance Schedule 7 - Line 15		\$20,497,197	\$18,171,175
Other Power Supply- Demand			
System Control & Load Dispatching	556	\$287,920	\$255,247
Other Expenses	557	\$1,413,020	\$1,252,670
Total OPS - Compliance Schedule 7 - Line 17		\$1,700,940	\$1,507,917

<u>Utility Operating Expense</u>	FERC	Total Company	MN Jurisdiction
Operations & Maintenance Exp.	<u>Acct No.</u>	Approved 2024	Approved 2024
		Cost of	Cost of
		<u>Service Model</u>	<u>Service Model</u>
Purchased Power			
Demand	555	\$72,141,496	\$63,954,879
Energy	555	\$286,503,520	\$246,135,174
Total Purchased Power - Compliance Schedule 7 - Line 18		<u>\$358,645,016</u>	<u>\$310,090,053</u>
Fuel			
Fuel	501	\$137,790,866	\$118,376,133
Total Fuel - Compliance Schedule 7 - Line 19		<u>\$137,790,866</u>	<u>\$118,376,133</u>
Total Production		<u>\$578,107,971</u>	<u>\$500,326,918</u>
Compliance Schedule 7 - Line 20		<u>\$578,107,971</u>	<u>\$500,326,918</u>

Note: Classification of expenses between demand and energy are based on FERC methodology used in prior rate cases. Accounts 501,510,512,513, & 544 are energy related, all others are demand.

Transmission Operation

Operation Supervision & Engineering	560	\$4,586,878	\$3,805,743
Load Dispatching -Reliability	561.1	\$1,776,233	\$1,473,745
Load Disp.-monitoring/operate trans sys.	561.2	\$4,937,364	\$4,096,542
Scheduling, system control & dispatch	561.4	\$2,221,766	\$1,843,404
Reliability, Planning & Stds. Develop.	561.5	\$847,388	\$703,080
Reliability, Planning & Stds. Develop.	561.8	\$159,750	\$132,545
Station Expenses	562	\$120,998	\$100,392
Transmission of Electricity by Others	565	\$32,955,514	\$27,343,266
Miscellaneous Transmission Expenses	566	\$714,562	\$592,874
Rents	567	\$3,166,496	\$2,627,249
Total Operation		<u>\$51,486,949</u>	<u>\$42,718,841</u>
Transmission Maintenance			
Supervision & Engineering	568	\$4,418	\$3,666
Maint Communications Equip.	569.3	\$2,319,774	\$1,924,722

		Total Company Approved 2024 Cost of Service Model	MN Jurisdiction Approved 2024 Cost of Service Model
<u>Utility Operating Expense</u>	FERC		
Operations & Maintenance Exp.	<u>Acct No.</u>		
Station Equipment	570	\$5,004,032	\$4,151,857
Overhead Lines	571	\$1,687,567	\$1,400,178
Overhead Lines - ROW Veg Ctl Only	571.01	\$3,617,701	\$3,001,615
Total Maintenance		<u>\$12,633,492</u>	<u>\$10,482,037</u>
Total Transmission - Compliance Schedule 7 - Line 21		\$64,120,441	\$53,200,878
Distribution Operation			
Supervision & Engineering	580	\$1,108,924	\$1,046,505
Load Dispatching	581	\$525,100	\$495,543
Overhead Line Expenses	583	\$235,130	\$221,895
Underground Line Expenses	584	\$77,782	\$73,404
Street Lighting & Signal Systems	585	\$123,564	\$116,609
Meters	586	\$1,757,326	\$1,736,986
Miscellaneous	588	\$5,991,157	\$5,653,925
Rents	589	\$78,664	\$74,236
Total Operation		<u>\$9,897,647</u>	<u>\$9,419,102</u>
Distribution Maintenance			
Supervision & Engineering	590	\$967,344	\$912,894
Station Equipment	592	\$3,000	\$2,831
Overhead Lines	593	\$6,662,000	\$6,287,008
Overhead Lines - ROW Veg Ctl Only	593.01	\$8,652,376	\$8,165,349
Underground Lines	594	\$1,844,414	\$1,740,595
Street Lighting & Signal Systems	596	\$32,562	\$30,729
Miscellaneous	598	\$1,267,340	\$1,196,004
Total Maintenance		<u>\$19,429,036</u>	<u>\$18,335,410</u>
Total Distribution - Compliance Schedule 7 - Line 22		\$29,326,683	\$27,754,513
Customer Accounts Expenses			
Supervision	901	\$55,874	\$55,394
Meter Reading Expenses	902	\$413,946	\$410,389

		Total Company Approved 2024 Cost of Service Model	MN Jurisdiction Approved 2024 Cost of Service Model
<u>Utility Operating Expense</u>			
Operations & Maintenance Exp.	FERC Acct No.		
Customer Records & Collection Exp	903	\$5,205,364	\$5,160,629
Uncollectible Accounts	904	\$1,261,712	\$1,250,869
Total Cust Accounts - Compliance Schedule 7 - Line 23		<u>\$6,936,896</u>	<u>\$6,877,280</u>
Customer Service & Info			
Customer Assistance Expenses	908	\$1,790,342	\$1,775,295
Informational & Instructional Advertising	909	\$18,389	\$18,234
Total Cust Service & Info - Compliance Schedule 7 - Line 24		<u>\$1,808,731</u>	<u>\$1,775,295</u>
Conservation Improvement Program			
Customer Assistance Exp-CIP	908.06	\$12,531,684	\$12,531,684
Total CIP - Compliance Schedule 7 - Line 25		<u>\$12,531,684</u>	<u>\$12,531,684</u>
Sales			
Advertising Expenses	913	\$24,373	\$24,373
Total Sales - Compliance Schedule 7 - Line 26		<u>\$24,373</u>	<u>\$24,373</u>
Administration & General			
A & G-Compensation & Other Expenses	920	\$34,744,406	\$30,865,761
Outside Services Employed	923	\$20,000	\$17,800
Property Insurance	924	\$6,849,536	\$6,041,426
Injuries and Damages	925	\$6,065,864	\$5,398,634
Injuries and Damages - Offset	925.99	-\$641,862	-\$571,259
EP&B - Life Insurance Expense	926.01	\$205,523	\$182,916
EP&B - Flexible Dollars	926.02	\$1,293,897	\$1,151,571
EP&B - Tuition Reimbursement	926.03	\$84,993	\$75,644
EP&B - Dental Plan	926.04	\$632,520	\$562,944
EP&B - Medical Plan	926.05	\$10,507,656	\$9,351,839
EP&B - ESOP (\$75M)	926.06	\$10,464,830	\$9,313,724
EP&B - Pension Plan	926.08	\$5,762,980	\$5,129,066

		Total Company Approved 2024	MN Jurisdiction Approved 2024
<u>Utility Operating Expense</u>	FERC	Cost of	Cost of
Operations & Maintenance Exp.	<u>Acct No.</u>	<u>Service Model</u>	<u>Service Model</u>
EP&B - EIP Survivor Benefits	926.09	\$85,680	\$76,255
EP&B - Other - Misc.	926.1	\$67,416	\$60,000
EP&B - FAS106-Post Retire. Ben.-Dental	926.11	-\$636,607	-\$566,582
EP&B - FAS106-Post Retire. Ben.-Life Insur.	926.12	\$207,960	\$185,085
EP&B - FAS106-Post Retire. Ben.-Medical	926.13	-\$8,695,572	-\$7,739,081
EP&B - FAS112-Post Employ Benefits	926.14	\$1,079,004	\$960,316
EP&B - upp. Exec. Retire. Plan	926.15	\$299,790	\$266,814
EP&B - Transfer Credit #1	926.99	-\$24,276,469	-\$21,606,116
Franchise Requirements	927	\$26,856	\$26,856
Regulatory Commission Expenses	928	\$5,224,793	\$4,527,529
General Advertising Expenses	930.1	-\$29,654	-\$26,392
Misc General Expenses	930.2	\$134,604	\$119,798
Stockholders Meetings Expenses	930.23	\$3,048	\$2,713
Bd of Directors" Fees and Expenses	930.24	\$1,531,642	\$1,363,165
Public Notices & Reports-Financial/Other	930.25	\$185,434	\$165,037
Maint of General Plant	935	\$21,571,981	\$19,199,115
TEMP - EV PROGRAM	EMP - EV PROGRAM	\$204,399	\$193,775
Total Admin & Gen - Compliance Schedule 7 - Line 27		\$72,974,647	\$64,728,354
Charitable Contributions			
Donations	426.10	\$257,786	\$229,430
Total Sales - Compliance Schedule 7 - Line 28		\$257,786	\$229,430
Interest on Customer Deposits			
Retail Interest Expense for Customer Deposits	431	\$2,520,000	\$2,520,000
Total Interest - Compliance Schedule 7 - Line 29		\$2,520,000	\$2,520,000
Grand Total - Operations & Maintenance Exp.		\$768,609,212	\$669,968,725
Compliance Schedule 7 - Line 30		\$768,609,212	\$669,968,725

Attachment 10
Notice of Reports Availability



30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com



Notice of Reports Availability

To: All Interveners in Minnesota Power
Retail Rate Proceedings
Docket Nos. E015/GR-21-335 and E015/GR-23-155

The Minnesota Public Utilities Commission requires Minnesota Power and other Minnesota public utilities to file various forecast reports concerning utility operations with the Commission as specified in Docket No. E999/CI-03-802. The subject matter of the report filed includes the following:

- 1) Independent Auditor's Report
- 2) Automatic Fuel Adjustment Clause Forecast to Actual Comparison
- 3) MISO Day 2 Charges and Allocations
- 4) ARR Information and Process
- 5) Plant Outage Reporting
- 6) Annual and Daily ASM Charges and Summary
- 7) Wind Curtailment Reporting
- 8) Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs)
- 9) Generation Facilities Maintenance Expense Report
- 10) Fuel and Energy Source Procurement and Energy Dispatching Policies

Minnesota Rule 7825.2840 requires Minnesota Power to provide this notice of availability of such reports to all Interveners in the previous two general rate cases. A copy of the above report is available for public inspection at the MPUC offices, 121 East 7th Place, Suite 350, St. Paul, MN 55101-2147, on the Minnesota Department of Commerce edockets website (<https://www.edockets.state.mn.us/EFiling>), or upon written request to the following:

Minnesota Power
Analeisha Vang
Regulatory Compliance Specialist, Senior
30 West Superior Street
Duluth, MN 55802

Please note that certain information contained in these reports is considered trade secret and is unavailable to the public.

Certificate of Service

It is hereby certified that the foregoing Notice of Report Availability, along with a copy of the report, was delivered to the Minnesota Department of Commerce and the Office of the Attorney General, and the interveners in Minnesota Power's previous two general rate cases.

Minnesota Power

By:

/s/ Analeisha Vang_____

Analeisha Vang
Regulatory Compliance Specialist, Senior

Dated: March 2, 2026

STATE OF MINNESOTA)
)ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

Susan Romans of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **2nd** day of **March, 2026** she served Minnesota Power's Petition for Approval of the Annual Forecasted Rates for its Rider for Fuel and Purchased Energy Charge in **Docket Nos. E015/AA-24-64, E015/GR-21-335 and E015/GR-23-155** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on the Official Service Lists for these Dockets were served as requested.



Susan Romans