In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota
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STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Minnesota Public Utilities Commission's Revised Procedures for Handling Trade Secret and Privileged Data in furtherance of Minn. Stat. § 13.37 and Minn. R. 7829.0500, Minnesota Power has designated portions of its Application for Authority to Increase Rates for Electric Utility Service in Minnesota ("Application") as Trade Secret.

The Application consists of Minnesota Power's interim and general rate case filings, which contain confidential financial, personnel, contractual, energy procurement, and third-party proprietary information that is materially sensitive and commercially valuable to Minnesota Power. Minnesota Power follows strict internal procedures to maintain the secrecy of all of this information in order to capitalize on the economic value of the information. As a result of public availability, Minnesota Power and its customers would suffer severe competitive implications, including a detrimental effect on energy costs paid by Minnesota Power's customers.

Minnesota Power believes that this statement and the attached Index of Non-Public Information Contained in Filing provide the justification as to why the information excised from the Application should remain a trade secret under Minn. Stat. § 13.37. The information contained in this schedule constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). The attached Index of Non-Public Information Contained in Filing summarizes the portions of the Application that have been designated as non-public and/or trade secret and the justification for that designation. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

Index of Non-Public/Trade Secret Information Contained in Filing

Item/Location	Justification
Volume 2, Direct Testimony and Supporting Schedules	
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Taran), Direct Schedules 1 and 4 – S&P Credit Report on ALLETE, Inc. (Aug. 3, 2026); S&P Credit Report on ALLETE, Inc. (May 8, 2025)	Schedules 1 and 4 are propriety reports prepared by a third-party vendor and provided to the Company on the condition that these reports be protected as trade secret and not publicly released. These reports derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from their disclosure or use, and the Company maintains these reports as trade secret pursuant to Minn. Stat. § 13.37, subd. 1(b). Because the Company has classified these entire reports as trade secret information, the Company provides the following description of the excised material as required by Minn. R. 7829.0500, Subp. 3: Nature of the Material: Subscription-based credit reports prepared by a third party. Author: S&P Global General Import: These documents represent credit rating information for ALLETE, Inc. and other financial information as generated by a third party, and which are received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret. Dates Prepared: August 3, 2026; May 8, 2025
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Taran), Direct Schedule 5 – Moody's Credit Opinion on ALLETE, Inc. (Dec. 23, 2025)	Schedule 5 is a propriety report prepared by a third-party vendor and provided to the Company on the condition that this report be protected as trade secret and not publicly released. This report derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, and the Company maintains this report as trade secret under Minn. Stat. § 13.37, subd. 1(b). Because the Company has classified this entire report as trade secret

Item/Location	Justification
	information, the Company provides the following description of the excised material as required by Minn. R. 7829.0500, Subp. 3: Nature of the Material: Subscription-based credit opinion prepared by a third party. Author: Moody's General Import: This document represents credit rating information for ALLETE, Inc. and other financial information as generated by a third party, and which is received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret. Date Prepared: December 23, 2025
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Anderson), Direct Schedule 5 – Moody's Credit Opinion on ALLETE, Inc. (Apr. 3, 2019)	Schedule 5 is a propriety report prepared by a third-party vendor and provided to the Company on the condition that this report be protected as trade secret and not publicly released. This report derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, and the Company maintains this report as trade secret under Minn. Stat. § 13.37, subd. 1(b). Because the Company has classified this entire report as trade secret information, the Company provides the following description of the excised material as required by Minn. R. 7829.0500, Subp. 3: Nature of the Material: Subscription-based credit opinion prepared by a third party. Author: Moody's Investors Service General Import: This document represents credit rating information for ALLETE, Inc. and other financial information as generated by a third party, and which is received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret.

Item/Location	Justification
	Date Prepared: April 3, 2019
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Anderson), Direct Schedule 8 – EEI Pension and OPEB Survey 2025-2026 and Select Results	Schedule 8 is propriety reports prepared by a third-party vendor and provided to the Company on the condition that these reports be protected as trade secret and not publicly released. These reports derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from their disclosure or use, and the Company maintains these reports as trade secret under Minn. Stat. § 13.37, subd. 1(b). Because the Company has classified these entire reports as trade secret information, the Company provides the following description of the excised material as required by Minn. Rule 7829.0500, Subp. 3: Nature of the Material: Utility retirement plan data in the form of survey results gathered and prepared by a third party. Author: Edison Electric Institute ("EEI") General Import: These documents represent the results of an EEI survey of member utilities' retirement plan components and associated cost recovery. EEI makes this material available to members, including Minnesota Power, by request, but prepares this document independently, maintains this list as proprietary and confidential, and does not share it with the general public. The data derives value for EEI, participants in the survey, and EEI members from not being readily ascertainable by the public, and therefore is maintained as a trade secret. Date Prepared: 2025-2026
Volume 2, Direct Testimony and Supporting Schedules, Direct Testimony and Schedules of Arik C. Forsman, Table 6, 2025 Taconite Facility Energy Intensity; Table 7, Large Power Customer Minimum Service Requirement Versus	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Item/Location	Justification
Full Production Revenue; Section V.C.1.c, Mesabi Metallics' customer load data; Section V.C.2, paper and pulp customer load data	
Volume 3, Required Filing Schedules	
Volume 3, Required Filing Schedules, Schedule H – 5A, Ten Highest Paid Officers and Employees' Compensation	Schedule H– 5A includes compensation information for the ten highest paid employees of the Company. Minn. Stat. § 216B.16, subd.17(c) allows for the salary of one or more of the ten highest paid officers and employees of Minnesota Power, other than the five highest paid, to be treated as private data on individuals. It also constitutes trade secret, information as defined by Minn. Stat. § 13.37, subd. 1(b) because it derives independent economic value from not being generally known to, and not being readily ascertainably by proper means by, other persons who can obtain economic value from its disclosure or use.
Volume 4, Workpapers	
Volume 4, Workpapers, AF-4, 2027 Jurisdictional & Class Customer Allocation; AF-5, 2026 Jurisdictional & Class Customer Allocation; AF-6, 2025 Jurisdictional & Class Customer Allocation	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers, COC-2, Risk Premium Analysis	The information contained herein includes financial information obtained from a third-party subscription-based platform. This information derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, and the Company maintains this information as trade secret under Minn. Stat. § 13.37, subd. 1(b).
Volume 4, Workpapers, COC-2, S&P Global State Adjustment Clauses Report (Sept. 2025)	The information contained herein is a propriety report prepared by a third-party vendor and provided to the Company on the condition that this report be protected as trade secret and not publicly released. This report derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain

Item/Location	Justification
	economic value from its disclosure or use, and the Company maintains this report as trade secret under Minn. Stat. § 13.37, subd. 1(b). Because the Company has classified this entire report as trade secret information, the Company provides the following description of the excised material as required by Minn. R. 7829.0500, Subp. 3: Nature of the Material: Subscription-based market report prepared by a third party. Author: S&P Global General Import: This document represents financial information as generated by a third party, and which is received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret. Date Prepared: September 2025
Volume 4, Workpapers, COC-2, Capital Structure Analysis; Change in Market Conditions Since the Utility's 2023 Rate Case; Authorized ROEs	The information contained herein includes financial information obtained from a third-party subscription-based platform. This information derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, and the Company maintains this information as trade secret under Minn. Stat. § 13.37, subd. 1(b).
Volume 4, Workpapers, COC-2, Customer Concentration Analysis	The information contained herein includes sales information obtained from a third-party subscription-based platform. This information derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, and the Company maintains this information as trade secret under Minn. Stat. § 13.37, subd. 1(b).
Volume 4, Workpapers, COC-2, MP Sales and Load Data	The information contained herein is customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota

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	Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure. Because the Company has classified this entire workpaper as trade secret information, the Company provides the following description of the excised material as required by Minn. R. 7829.0500, Subp. 3: Nature of the Material: Customer sales and load data. Author: The Brattle Group General Import: This document represents customer data, which is protected under the Minnesota Data Practices Act, and therefore is maintained as a trade secret. Date Prepared: 2026
Volume 4, Workpapers, OS-2, Lead Lag Study	The information designated as trade secret herein is contractually-negotiated pricing information and is trade secret information as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as trade secret.
Volume 4, Workpapers, OS-3, Minnesota Power's 2025 Annual Electric Utility Forecast Report; OS-4, Minnesota Power's 2026 Annual Electric Utility Forecast Report	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota
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Statement on Rounding

Due to rounding, numbers on schedules presented throughout this filing may not add up precisely to the totals indicated, and percentages may not precisely reflect the absolute figures for the same reason. The cost of service study, on which many of these supporting schedules are based, is calculated using factors which go out to additional decimal points beyond those listed in the schedules. For display purposes, the schedules are rounded to the nearest whole dollar and subtotals and subsequent totals in the cost of service study may be based on actual values. This may result in occasional minor differences between the subtotals and totals on the cost of service study and those on supporting schedules.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota	Docket No. E015/GR-26-199 **SUMMARY OF FILING**

On November 2, 2026, Minnesota Power filed with the Minnesota Public Utilities Commission ("Commission") an Application for Authority to Increase Electric Service Rates in Minnesota. Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power requests a final increase in gross revenues, net of rider roll-ins, of $134.4 million, or 17.83 percent (which equates to an increase in revenues of $166.7 million, or 22.09 percent including rider roll-ins), effective January 1, 2027, without suspension. Minnesota Power also proposes changes to its rate design. If the Commission suspends the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, pursuant to Minn. Stat. § 216B.16, subd. 3 Minnesota Power requests an interim revenue increase, net of rider roll-ins and transfers, of $116.7 million, or 15.48 percent (which equates to an interim revenue increase of $148.9 million, or 19.75 percent including rider roll-ins) effective on January 1, 2027, with final rates effective within ten months of the date of the Application.

The average impact of the proposed increase for residential customers with an average usage of 663 kilowatt hours per month will be approximately $24 per month or $288 annually. If the requested rates are suspended, the interim rates will increase the bill for a typical residential customer with average usage by approximately $15 per month or $180 annually. The impact on individual customers will be higher or lower depending on each customer's actual consumption.

The proposed rate schedules and a comparison of present and proposed rates are available at https://www.mnpower.com/RateRequest or at the Minnesota Department of Commerce, 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101. This filing is also available through the eDockets link on the Commission website at mn.gov/puc, under Docket No. E015/GR-26-199.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota	Docket No. E015/GR-26-199 **NOTICE OF CHANGE IN RATES**

A. Introduction

In this Application for Authority to Increase Electric Service Rates in Minnesota ("Application"), Minnesota Power seeks authority from the Minnesota Public Utilities Commission ("Commission") to increase retail electric rates in Minnesota pursuant to Minn. Stat. § 216B.16 and Minn. R. 7825.3100–7825.4600 and 7829.2400. Minnesota Power requests that the Commission authorize a net base rate increase of $134.4 million Minnesota jurisdictional (approximately 17.83 percent), exclusive of transferring costs of the Duluth Loop Reliability Project from the Transmission Cost Recovery Rider ("TCR") to base rates and resetting the Production Tax Credit ("PTC") baseline with an accompanying change in the Renewable Resources Rider ("RRR"). This equates to a requested base rate increase of 22.09 percent based on the Company's gross Minnesota jurisdictional revenue deficiency of approximately $166.6 million.

If the Commission elects to suspend the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, Minnesota Power requests, pursuant to Minn. Stat. § 216B.16, subd. 3, that an interim rate increase be effective on January 1, 2027, with final rates becoming effective within ten months of the date of this Application. The interim rate increase is $116.7 million Minnesota jurisdictional, or approximately 15.48 percent, net of moving the Duluth Loop Reliability Project to base rates and resetting the PTC baseline. This equates to a requested gross interim rate change of 19.75 percent based on the Company's Minnesota jurisdictional interim revenue deficiency of approximately $148.9 million.

This Application includes the following information in accordance with Minnesota Statutes and the Commission's rules:

B. Notice and Proposal Regarding General Rate Change

(Minn. R. 7825.3200(A)(1) and 7825.3500)

1. Name, address, and telephone number of utility.

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2641

2. Name, address, and telephone number of attorneys for the utility.

Matthew R. Brodin
Senior Regulatory Counsel
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3152

Elizabeth M. Brama
Valerie T. Herring
Kodi J. Verhalen
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
(612) 977-8400

3. Date of filing and date modified rates are to be effective.

The date of this filing is November 2, 2026. Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power respectfully requests that the overall rate increase it proposes become effective January 1, 2027, without suspension. A schedule of rates and tariffs reflecting the revenue increase requested and the proposed rate design described in the attached documents is included with the Application.

If the Commission suspends the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, Minnesota Power respectfully requests, pursuant to Minn. Stat. § 216B.16, subd. 3, that the Commission approve the interim rate increase proposed in the Petition for Interim Rates, which is filed as part of this Application, effective January 1, 2027, with final rates effective within ten months of the date of this Application.

4. Description and purpose of the change in rates requested.

The Application for a change in rates applies to all Minnesota Power retail customers in the State of Minnesota. The overall purpose of the proposed rate change is to produce the additional revenue necessary to meet Minnesota Power's cost of service for the test year ending December 31, 2027. This filing complies with the provisions of Minn. Stat. § 216B.16 and the Commission's rules governing rate changes.

5. Effect of the change in rates.

The effect of the proposed rate increase, which is based on the Company's proposed 2027 test year revenue deficiency, is a general increase in rates for retail electric service of

approximately $134.4 million (17.83 percent), net of rider amounts moving to base rates. Without the associated decrease to riders, the base rate change is approximately $166.6 million (22.09 percent overall). If the Commission should suspend the Application, the Company is requesting an increase to interim rates of approximately $116.7 million or about 15.48 percent net of offsetting rider decreases, which equates to a gross interim increase to base rates of approximately $148.9 million (19.75 percent overall).

6. Signature and title of utility officer authorizing the proposal.

The Application is signed on behalf of Minnesota Power by Joshua J. Skelton, ALLETE Vice President & Chief Operating Officer – Minnesota Power.

C. Modified Rates (Minn. R. 7825.3200(A)(2) and 7825.3600)

Included in this Application are rate schedules containing the proposed changed rates and tariffs. General rate schedules and tariffs are included in Volume 3 of this Application and are supported by the Direct Testimony of Company witnesses Amanda L. Turner, Levi A. Peterson, and Leah N. Peterson.

D. Expert Opinions and Supporting Documents (Minn. R. 7825.3200(A)(3) and 7825.3700)

The statements of fact, expert opinions, and substantiating documents and exhibits supporting Minnesota Power's proposed change in rates accompany this Application. Pursuant to Minn. R. 7825.3700, Jennifer J. Cady provides Direct Testimony as Minnesota Power's designated official in support of the Application. A list of Minnesota Power's other witnesses is provided in the Direct Testimony of Company witness Cady.

E. Information Requirements (Minn. R. 7825.3200(A)(4) and 7825.3800 to 7825.4400)

Included in this Application in Volume 2 are the Direct Testimonies of Minnesota Power's witnesses. Volumes 1 and 3 contain the Company's interim and proposed general rate tariffs and Volume 3 contains Minnesota Power's Information Requirements. These volumes, along with Volume 4, Workpapers, represent Minnesota Power's supporting documentation and contain the information in support of the general rate increase requested in this proceeding and as required by Minn. R. 7825.3800 through Minn. R. 7825.4400.

Data are provided for the 2025 most recent fiscal year and the 2026 projected year. The proposed test year is the calendar year ending December 31, 2027. Minn. Rule 7825.3100, Subp. 10 defines "most recent fiscal year" as "the utility's prior fiscal year unless notice of a change in rates is filed with the [C]ommission within the last three months of the current fiscal year and at least nine months of historical data is available for presentation of current fiscal year financial information, in which case the most recent fiscal year is deemed to be the current year." As discussed in the Direct Testimony of Company witness Amanda L. Turner, ALLETE's 2026 Third Quarter financial results will be released in November of 2026, after the date of this filing. Therefore, 2025, the prior fiscal year, is the most recent fiscal year for which data is available as of the date of filing. Treatment of 2025 as the "most recent fiscal year" is consistent with both the

plain language of Minn. R. 7825.3100, Subp. 10, and Minnesota Power's most recent rate case filings in Docket Nos. E015/GR-23-155, E015/GR-21-335, E015/GR-19-442, E015/GR-16-664, and E015/GR-09-1151.

In the event the Commission concludes the Company requires a variance to treat 2025 as its most recent fiscal year, Minnesota Power meets each of the requirements for the Commission to grant a variance under Minn. R. 7829.3200. In particular: (1) enforcement of the rule would impose an excessive burden upon the Company, as the necessary data for 2026 is not available as of the date of this filing; (2) granting the variance would not adversely affect the public interest because Minnesota Power has used this approach in the past and it has result in just and reasonable rates; and (3) granting a variance would not conflict with standards imposed by law.

F. Methods and Procedures for Refunding (Minn. R. 7825.3200(A)(5) and 7825.3300)

This Application is accompanied by an "Agreement and Undertaking" signed and verified by Joshua J. Skelton, ALLETE Vice President & Chief Operating Officer – Minnesota Power, which commits Minnesota Power to make any refunds ordered by the Commission.

G. Notice to Municipalities and Counties (Minn. Stat. § 216B.16, subd. 1 and Minn. R. 7829.2400, Subp. 3)

Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power proposes to mail the Proposed Notice to Counties and Municipalities included with the Application to all municipalities and counties in Minnesota Power's Minnesota electric service territory. This notice includes a discussion of the proposed interim rates, as well as information regarding the general electric rate case filing. Minnesota Power respectfully requests Commission approval of the notice so it may be mailed in a timely fashion.

H. Customer Notice (Minn. R. 7829.2400, Subp. 3)

Minnesota Power will send a rate change notice to retail customers as a bill insert that explains the proposed general rate increase. If Minnesota Power's requested retail electric rate increase is suspended, Minnesota Power will also explain the impact of its interim rates on customer bills in the same bill insert. Included in this Application is a proposed customer notice of rate increase. Minnesota Power will work with Commission Staff to revise the notice as necessary so that Minnesota Power may insert the notices in the first bill a customer receives containing changed rates.

Minnesota Power will also publish public notice of the rate change in the newspapers of general circulation in all county seats in Minnesota Power's electric service territory. Included in this Application is an example of Minnesota Power's proposed newspaper notice. Minnesota Power will work with Commission Staff to revise the notice as necessary for prompt Commission approval. Minnesota Power will publish the newspaper notice as directed by the Commission.

I. Filings Requiring Determination of Gross Revenue Requirement (Minn. R. 7829.2400)

Pursuant to Minn. R. 7829.2400, Minnesota Power submits the following information in addition to that required by Minn. R. 7825.3100–7825.4600.

1. Summary (Minn. R. 7829.2400, Subp. 1)

A summary of the Application is attached to this Notice.

2. Service; Proof of service (Minn. R. 7829.2400, Subp. 2)

Minnesota Power has served copies of the Application on the Minnesota Department of Commerce, Division of Energy Resources, and the Office of the Attorney General – Residential Utilities Division. Minnesota Power will serve a copy of the Summary of Filing on all parties on Minnesota Power's general service list and on the parties to Minnesota Power's last filed rate case proceeding (Docket No. E015/GR-23-155). A certificate of service is attached.

3. Notice to public and governing bodies (Minn. R. 7829.2400, Subp. 3)

See Sections G and H above.

4. Notice of Hearing (Minn. R. 7829.2400, Subp. 7)

Minnesota Power will notify customers of hearings held in connection with this Application as directed by the Commission. Minnesota Power will also publish notice of the hearings in newspapers of general circulation in all county seats in Minnesota Power's electric service area, as directed by the Commission. *See also* Section H above.

J. Request for Protection of Non-Public Information

Minnesota Power recognizes and supports the need for transparency in the review of its Application. A limited number of schedules and workpapers in the Application include Non-Public Data according to Minn. Stat. § 13.37, subd. 1(b) and Minn. R. 7829.0500. Minnesota Power has taken reasonable efforts to maintain the secrecy of this Non-Public Data, which derives independent economic value, actual or potential, from not being generally known to—and not being readily ascertainable by proper means by—other persons who can obtain economic value from its disclosure or use.

Minnesota Power provides an index of non-public information contained in this filing with its Statement Regarding Justification for Excising Trade Secret Information in Volume 1 of the Application, which summarizes the documents and exhibits that have been designated as nonpublic and/or trade secret in part or in full and the justification for those designations. Minnesota Power is filing complete Public and Non-Public versions of the portions of this Application that contain trade secret or non-public information.

K. Service List

Pursuant to Minn. R. 7829.0700, Minnesota Power respectfully requests the following persons representing Minnesota Power be placed on the Commission's official service list for this proceeding:

Matthew R. Brodin
Minnesota Power
30 West Superior Street
Duluth, MN 55802
mbrodin@allete.com

Jennifer Kuklenski
Minnesota Power
30 West Superior Street
Duluth, MN 55802
jkuklenski@mnpower.com

Susan Ludwig
Minnesota Power
30 West Superior Street
Duluth, MN 55802
sludwig@mnpower.com

Kayla Coffee-Prose
Minnesota Power
30 West Superior Street
Duluth, MN 55802
kcoffeeprose@mnpower.com

Elizabeth M. Brama
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
ebrama@taftlaw.com

Valerie T. Herring
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
vherring@taftlaw.com

Kodi J. Verhalen
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
kverhalen@taftlaw.com

L. Conclusion

Minnesota Power respectfully requests consideration and acceptance of its Application and the accompanying Notices to municipalities and counties, customers, and the public.

Dated: November 2, 2026

Respectfully submitted,

Joshua J. Skelton
ALLETE Vice President & Chief Operating Officer – Minnesota Power
30 West Superior Street
Duluth, MN 55802

Subscribed to before me this 2nd day of November, 2026

Notary Public

AMY M HONKALA
NOTARY PUBLIC
MINNESOTA
My Commission Expires January 31st 2028

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	Docket No. E015/GR-26-199 **NOTICE AND PETITION FOR INTERIM RATES**

A. Introduction

Minnesota Power hereby respectfully submits to the Minnesota Public Utilities Commission ("Commission") this Petition for Interim Rates ("Petition") pursuant to Minn. Stat. § 216B.16, subd. 3, the Commission's Statement of Policy on Interim Rates dated April 14, 1982, and relevant Commission rules. Based on calculation of the Company's gross present revenues and the interim revenue deficiency set forth in the Schedules supporting this Petition, the Company is experiencing a $116.7 million, or 15.48 percent, interim revenue deficiency exclusive of transferring costs of the Duluth Loop Reliability Project from the Transmission Cost Recovery Rider ("TCR") to base rates and resetting the Production Tax Credit ("PTC") baseline with an accompanying change in the Renewable Resources Rider ("RRR"). This equates to a gross interim rate change of 19.75 percent or approximately $148.9 million. Minnesota Power requests that the Commission authorize an interim rate increase reflecting its gross interim revenue deficiency effective January 1, 2027, and remaining in effect until the Company implements final rates in this proceeding.

Minnesota Power has filed only five completed rate cases in the last 30 years,[1] the last of which was filed three years ago and resolved via a comprehensive and unanimous settlement

[1] Minnesota Power also submitted a general rate case in 2019; however, the Company withdrew its 2019 rate request via settlement with intervening parties due to the COVID-19 pandemic.

approved by the Commission. During these three years, the Company has experienced a significant reduction in sales due to idling of two industrial customer taconite mining facilities, and also experienced a significant increase in costs associated with federal environmental regulation compliance, inflation, increased labor costs, higher interest rates, and other external pressures. Nonetheless, as part of the Company's acquisition approved in Docket No. E015/PA-24-198, the Company agreed to a one-year rate case stay-out for the benefit of customers. Additionally, in 2027 the Company will be providing proceeds from the sale of land associated with Minnesota Power's hydroelectric operations to customers, as well as implementing a shareholder-funded $10 million customer rate credit. Together, these credits will offset more than 70 percent of the interim rate impact on Minnesota Power's customers in 2027. The Company has also carefully reviewed its general rate request in this proceeding, to ensure interim rates are no higher than necessary, as described later in this Petition. Minnesota Power therefore respectfully requests the implementation of its interim rate request pursuant to Minn. Stat. § 216B.16, subd. 3.

B. Information Provided Pursuant to the Commission Statement of Policy on Interim Rates and Relevant Commission Rules

1. Name, address, and telephone number of utility and attorneys (Policy Statement, Item 1, page 2)

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2625

Matthew R. Brodin
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3152

Elizabeth M. Brama
Valerie T. Herring
Kodi J. Verhalen
Taft, Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
(612) 977-8400

2. Date of filing and date proposed interim rates are requested to become effective
(Policy Statement, Item 2, page 2)

The date of the submission of this Petition is November 2, 2026. This Petition is submitted as part of Minnesota Power's Application for a general electric rate increase ("Application") pursuant to Minn. Stat. § 216B.16, subd. 3. Minnesota Power requests that, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. § 216B.16, subd. 2, that the proposed interim rates be made effective on January 1, 2027. The interim rates will be subject to refund, with interest, pending final Commission determination on the Application.

3. Description and need for interim rates
(Policy Statement, Item 3, page 2)

Over the last few decades, Minnesota Power has transformed its generation fleet and added other internal resources that are assisting Minnesota Power in achieving the State of Minnesota's goal of providing 100 percent carbon-free electricity by 2040; modernizing its transmission grid to facilitate the delivery of renewable energy; investing in its aging distribution grid to ensure it is reliable and resilient; and offering extensive customer conservation and affordability programs.

Since its last rate case filed three years ago, Minnesota Power has experienced increases in the costs of providing safe, reliable, and affordable electric service, combined with a substantial reduction in retail sales primarily from the Hibbing Taconite and Minorca taconite mines. Cost increases include a variety of factors outside the Company's control, including inflation, supply chain limitations, compliance with federal environmental regulations, increased labor costs, and rising interest rates. Even so, over the last decade and through the anticipated 2027 test year, Minnesota Power is maintaining average operations and maintenance ("O&M") expense levels below the average rate of inflation, all while transforming its fleet, addressing risks to the grid,

maintaining near-perfect reliability, and supporting its customers. These changes are described in detail in the Company's Direct Testimony in this case, including the Case Overview testimony of Company witness Jennifer J. Cady.

Minnesota Power, in partnership with stakeholders and the Commission, has also been proactive and creative in maximizing opportunities to moderate rates for its customers. Minnesota Power has met and exceeded conservation goals for a number of years, and has developed new rates and services that enable residential and commercial customers to reduce their consumption and overall energy bills. Additionally, as part of the Acquisition settlement, the Company, in conjunction with its current owners, agreed not to file a rate case before November 1, 2026. The Company's revenue deficiency for calendar year 2026, combined with its agreement to stay out of a rate case for one year, provided approximately $100 million in value to customers. In addition, the Company's agreement to provide $72.5 million in land sales proceeds and $10 million in bill credits to customers in 2027 will offset more than 70 percent of 2027 interim rates. This is in addition to other agreed outcomes from Docket No. E015/PA-24-198, including caps on the Company's rate of return on equity ("ROE"), equity ratio, limitations on recovery of certain investor and Board costs; $3.5 million in arrearage forgiveness; and $50 million in shareholder-funded longer-term investments in clean, firm technology.

These benefits are flowing to customers, and Minnesota Power has gone further to limit its interim rate request in this proceeding. In addition to the adjustments to align its interim rates with the interim rate formula in Minn. Stat. § 216B.16, subd. 3, Minnesota Power evaluated its test year budget for other opportunities to reduce costs for customers. While it is critical for Minnesota Power to fill open employment positions to serve customers and support the increasing needs of the Company's electric operations, the pace of hiring is currently slower than hoped. The Company has increased its hiring efforts and, in the meantime, removed from interim rates $5 million for the estimated compensation and benefits associated with as-yet unfilled positions. Minnesota Power expects to continue filling these positions during the test year, and as a result of this adjustment may not fully recover the costs of new employees from the time they are hired. However, this adjustment is in keeping with Minnesota Power's philosophy that it only requests recovery of costs it expects to incur to provide quality electric service to customers. Minnesota Power is also proposing a Sales Adjustment Mechanism that will ensure that if the Company has any large retail load increases not reflected in rates, those benefits will be shared with customers.

As the Company nonetheless continues to experience increases in necessary costs at the same time two of the largest industrial mines are idled in whole or part, interim rate relief is critical to better align the Company's operating revenue with its costs, to ensure Minnesota Power can continue providing safe and reliable electric service while also meeting state policy goals well into the future. Without interim rate relief, Minnesota Power would continue to be unable to recover its reasonable costs of providing electric service to its customers, and would not have a reasonable opportunity to earn its authorized rate of return. As a result, the Company must re-establish rates that reflect current revenue and cost structures and support a financially healthy utility.

Minnesota Power also stands ready to support customers who may need assistance with their electric bills in a range of ways. Minnesota Power offers a best-in-class Customer Affordability of Residential Electricity ("CARE") program that includes a self-declare eligibility process to eliminate barriers to participation. As detailed in the Company's most recent CARE Annual Report, Minnesota Power has continued implementing program enhancements designed to increase customer participation, expand access to CARE discounts, and reopen the affordability discount to new applicants. Additionally, the Company offers flexible billing arrangements, and in 2026 implemented an On Track arrears forgiveness program funded by the Company's shareholders. Minnesota Power also continues to encourage conservation as both an environmental benefit and a means of saving on electric bills; for example, the Company's shareholder-funded Long-Term Residential Energy Bill Mitigation Fund will provide $10 million in long-term bill mitigation for income-qualified customers through weatherization, energy efficiency, and electrification improvements, with particular attention to households using delivered fuels for space and water heating.

Volume 1, Direct Schedules A (IR) through F (IR) and Volume 4, Workpapers accompanying this Petition set forth the calculation of the gross Minnesota jurisdictional interim revenue deficiency of approximately $148.9 million, which represents a 19.75 percent gross interim rate change. Volume 1, Direct Schedule B-11 (IR) sets forth the calculation of the net Minnesota jurisdictional interim revenue deficiency of approximately $116.7 million, which represents a 15.48 percent net interim rate change. Minnesota Power's interim revenue deficiency is determined using the 2027 test year revenue requirement, with the proposed adjustments set forth below consistent with Minnesota Statutes and Rules. Minnesota Power calculated its proposed interim rates consistent with Commission requirements and precedent.

Minnesota Power requests that the proposed interim rate increase be applied to all classes of Minnesota Power's retail electric customers, but not to the following services, consistent with Commission application of interim rates in the Company's prior rate cases: Large Power Incremental Production Services, Economy/Non-firm Service, Replacement Firm Power Service, and service fees. Revenue associated with these rate components is not considered part of the Large Power class revenue in the CCOSS, and these services are priced based on Minnesota Power's hourly incremental energy cost or other separately-negotiated terms.

Riders to Base Rates

For purposes of both interim rates and final base rates, the Company proposes to incorporate approximately $9.2 million (MN jurisdictional) that is currently being recovered under the TCR Rider for the Duluth Loop Reliability Project. As detailed in the testimony of Company witnesses Levi A. Peterson and Amanda L. Turner, this amount presently included in the TCR Rider will simply be moved from the rider into base rates effective January 1, 2027, offsetting the gross interim base rate increase. The Company also proposes to reset the baseline level federal PTCs in the RRR, which increases base rates by approximately $23.0 million (MN jurisdictional). This reset is detailed in the testimony of Company witnesses Levi Peterson and Rena Verdoljak. Collectively, these transfers of rider costs into base rates account for more than 20 percent of the Company's interim rate request.

Interim Rate Adjustments from General Rate Request

The costs included in interim rates are appropriate for recovery in interim rates because they are "the same in nature and kind as those allowed" by the Commission Order in Minnesota Power's last electric rate proceeding. Minn. Stat. § 216B.16, subd. 3. To further comply with this statute, the Company proposes the following adjustments to the 2027 test year proposed final revenue requirement, which reflect differences between Minnesota Power's final rate request and interim rate request in this proceeding:

- ***Pro Rata Accumulated Deferred Income Tax ("ADIT").*** Under Internal Revenue Service ("IRS") normalization requirements, utilities who use forecast test years for determination of rates must calculate average ADIT using a pro rata method for interim rates, but not

final rates. Thus the Interim Rate calculation, but not the General Rate calculation, reflects the pro rata ADIT methodology.

- ***Prepaid Pension Asset and Prepaid Other Post-Employment Benefits ("OPEB").*** As Minnesota Power has not previously received approval to recover the costs of its accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset) or prepaid OPEB, this asset is not of the same nature and kind as those allowed by the currently-effective Commission Order and are not included in rate base in the Company's Interim Rate calculation. Consistent with past Commission orders and treatment of this asset, Minnesota Power has also removed the associated ADIT from the Interim Rate calculation.
- ***Electric Vehicle ("EV") Direct Current Fast Chargers ("DCFC").*** In its previous rate case, the Company removed costs associated with the EV DCFC Project from its cost-of-service study. Because those costs were not previously included in base rates, the Company makes rate base and operating income adjustments to exclude EV DCFC costs from its Interim Rate calculation.
- ***Service Extension Costs.*** Minnesota Power is proposing changes to its service extension process and customer charges; however, these changes are not expected to take effect until the case concludes. Accordingly, an adjustment to General Rates, but not Interim Rates, is necessary to reflect the appropriate expected plant amounts associated with these changes.
- ***Years of Service Awards.*** In the Company's 2021 Rate Case and pursuant to the settlement approved in its 2023 Rate Case, the Commission disallowed certain employee award expenses, including Service Awards and Retirement Awards; therefore, these expenses are not included in the Interim Rate calculation.
- ***Employee Count.*** To account for the Company's ongoing efforts to achieve budgeted 2027 staffing levels as discussed elsewhere in this Petition, the Company is making a downward adjustment to employee-related operating expenses for purposes of Interim Rates.
- ***Long-Term Incentive Program.*** Expenses associated with the Company's redesigned long-term incentive compensation program were not included in the 2023 Rate Case and were not permitted for recovery in the Company's 2021 Rate Case. As such, these expenses are excluded from the Interim Rate calculation.

- ***Rate of Return on Equity.*** Consistent with the requirements of Minn. Stat. § 216B.16, subd. 3(b), the return on equity included in interim rates is 9.65 percent, which is the return on equity ("ROE") approved by the Commission in Docket E015/PA-24-198. The Company also filed notice of this change in its 2023 Rate Case docket. This amount is reduced from the Company's requested final rate ROE of 9.78 percent.
- ***Secondary Calculations.*** Cash working capital and interest synchronization are secondary calculations that need to be recalculated during the course of the proceeding to reflect changes to operations and maintenance ("O&M") expenses, rate base, and capital structure. The Company's Interim Rate schedules reflect the appropriate calculations for determination of the interim revenue requirement.

These adjustments are described by Company witness Turner in her Direct Testimony. Further, each of the Company's adjustments for purposes of interim rates for the Minnesota Jurisdiction are set forth in Volume 1, Direct Schedules B-3 (IR) (Rate Base Adjustments – Minnesota Jurisdiction), B-7 (IR) (Operating Income Adjustments – Minnesota Jurisdiction), B-9 (IR) (Interest Synchronization Adjustment), B-10 (IR) (Summary of Revenue Requirements), and C-6 (IR) (Capital Structure and Rate of Return Calculations).

Consistent with Minn. Stat. § 216B.16, subd. 3, the Company is proposing the same allocation methodology for its Interim Class Cost of Service Study ("CCOSS") as was approved by the Commission in the 2023 Rate Case.

4. Description and corresponding dollar amount of changes included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available (Policy Statement, Item 4, page 2)

A comparison of the changes included in interim rates as compared with Minnesota Power's 2023 Rate Case (Docket No. E015/GR-23-155) is contained along with this Petition in Volume 1, Direct Schedules C (IR) (Comparison of Proposed Interim Rates to Most Recent General Rate Case) and Schedules D (IR) (Comparison of Proposed Interim Rates to Most Recent Fiscal Year).

5. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues (Policy Statement, Item 5, page 2)

The test year for Minnesota Power's general rate increase filing is the calendar year ending December 31, 2027. Net of Duluth Loop and PTC transfers from riders, the interim test year revenue increase request is approximately $116.7 million, or 15.48 percent. Including costs and allowances being transferred from riders to base rates, the gross increase in interim test year revenues is $148.9 million, or approximately 19.75 percent above present base rate components.

6. Certification by officer of the utility (Policy Statement, Item 6, page 2)

This Petition contains a Certification signed by Joshua J. Skelton, ALLETE Vice President & Chief Operating Officer – Minnesota Power, affirming that this Interim Rate Petition complies with Minnesota Statutes.

7. Methods and procedures for refunding

Pursuant to Minn. Stat. § 216B.16, subd. 3, this filing contains Minnesota Power's Agreement and Undertaking of Refund.

8. Signature and title of the utility officer authorizing the proposed interim rates (Policy Statement, Item 7, page 2)

This Petition is signed by Joshua J. Skelton, ALLETE Vice President & Chief Operating Officer – Minnesota Power.

9. Supporting schedules and workpapers (Policy Statement, Items 1-4, page 3)

The supporting schedules and workpapers described in the Commission's Policy Statement are included with this Petition. These schedules include the rate base amounts, income statement amounts, revenue deficiencies, capital structures, and rates of return required for interim rates as compared to: (1) the same information for Minnesota Power's general rate increase Application (Schedules F (IR)); (2) the allowed amounts in Minnesota Power's 2023 Rate Case (Schedules C (IR)); and (3) the most recent actual year (Schedules D (IR)). The schedules and workpapers

containing the jurisdictional cost of service study and supporting the interim rate data are included in Volume 1, Schedules A (Interim Jurisdictional Financial Summary Schedules), and Schedules B (Proposed Interim Rate Schedules), and in Volume 4 Workpapers, Interim Rates, IR-1 and IR-2, and Volume 4, Workpapers, Cost of Service, COS-1 – Cost of Service Interim Test Year 2027.

10. Interim rate schedules; Revenue rate comparisons (Minn. R. 7825.3600)

The rate schedules containing proposed interim rates are included along with this Petition in Volume 1, Interim Tariff Sheets – Redlined and Interim Tariff Sheets – Clean. Consistent with Minn. Stat. § 216B.16, subd. 3, no change has been made in the existing rate design. Included with this Petition is a schedule of interim revenue impacts in the Comparison of Revenues – Present and Proposed Interim Rates, Volume 4 Workpapers, IR-1.

11. Customer notice (Minn. R. 7829.2400, Subp. 3; Minn. Stat. § 216B.16, subd. 1)

Pursuant to Minn. R. 7829.2400, Subp. 3 and Minn. Stat. § 216B.16, subd. 1, Minnesota Power proposes to send a notice to the counties and municipalities it serves in Minnesota and a bill insert to its electric customers in the State of Minnesota. The proposed notice to counties and municipalities and a proposed customer notice pursuant to Minn. Stat. § 216B.16, subd. 1, are included with this filing. Minnesota Power will work with Commission Staff immediately to revise the notices as necessary for prompt Commission approval so that Minnesota Power can include the customer notices with the first bills issued with the interim rates. In addition, Minnesota Power will publish a display advertisement in the newspapers of general circulation in all county seats in Minnesota Power's service territory as ordered by the Commission. The display advertisement will replicate the notice to the counties and municipalities, and will describe the rate schedules applicable to various customer classes. Minnesota Power's proposed customer notice, proposed notices to counties and municipalities, and list of counties and cities are included in this Volume 1.

12. Interim rate bills

The Commission's Policy Statement on Interim Rates suggests that changes in interim rates be shown on customer bills as a separate line item "if practical." The interim rate amount will be

shown as a separate line item identified as "Interim Rate Adjustment" and will reflect the total amount of the interim charge applied to the bill.

C. Conclusion

Minnesota Power hereby respectfully submits this Notice and Petition for Interim Rates. If the Commission suspends the operation of the general rate schedules under Minn. Stat. § 216B.16, subd. 2, Minnesota Power respectfully requests that the Petition for Interim Rates be promptly considered and accepted by the Commission, and that the interim rate schedule be approved and made effective on January 1, 2027, pursuant to Minn. Stat. § 216B.16, subd. 3, subject to refund pending final Commission action on the general rate increase Application.

Dated: November 2, 2026

Respectfully submitted,

Joshua J. Skelton
ALLETE Vice President & Chief Operating Officer – Minnesota Power
30 West Superior Street
Duluth, MN 55802

Subscribed to before me this 2nd day of November, 2026

Notary Public

AMY M HONKALA
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Volume 1 Index - Interim Rate Schedules

	Schedule Name
A. Interim Jurisdictional Financial Summary Schedules	
Revenues and Percent Increase	Direct Schedule A-1 (IR)
Summary of Revenue Requirements	Direct Schedule A-2 (IR)
Detailed Rate Base Components	Direct Schedule A-3 (IR)
Statement of Operating Income	Direct Schedule A-4 (IR)
B. Proposed Interim Rates Schedules	
Detailed Rate Base Components	Direct Schedule B-1 (IR)
Description of Adjustments to Rate Base	Direct Schedule B-2 (IR)
Rate Base Adjustments – Minnesota Jurisdiction	Direct Schedule B-3 (IR)
Rate Base Adjustments - Total Company	Direct Schedule B-4 (IR)
Statement of Operating Income	Direct Schedule B-5 (IR)
Description of Adjustments to Operating Income	Direct Schedule B-6 (IR)
Operating Income Adjustments - Minnesota Jurisdiction	Direct Schedule B-7 (IR)
Operating Income Adjustments - Total Company	Direct Schedule B-8 (IR)
Interest Synchronization Adjustment - Total Company	Direct Schedule B-9 (IR)
Summary of Revenue Requirements	Direct Schedule B-10 (IR)
Interim Rate Increase - Net of Riders	Direct Schedule B-11(IR)
C. Comparison of Proposed Interim Rates to Most Recent General Rate Case	
Detailed Rate Base Components	Direct Schedule C-1 (IR)
Description of Changes to Rate Base	Direct Schedule C-2 (IR)
Statement of Operating Income	Direct Schedule C-3 (IR)
Description of Changes to Operating Income	Direct Schedule C-4 (IR)
Summary of Revenue Requirements	Direct Schedule C-5 (IR)
Capital Structure and Rate of Return Calculations	Direct Schedule C-6 (IR)
Description of Changes to Capital Structure and Rate of Return	Direct Schedule C-7 (IR)
Summary of Comparison of Revenues	Direct Schedule C-8 (IR)
D. Comparison of Proposed Interim Rates to Most Recent Fiscal Year	
Detailed Rate Base Components	Direct Schedule D-1 (IR)
Description of Changes to Rate Base	Direct Schedule D-2 (IR)
Statement of Operating Income	Direct Schedule D-3 (IR)
Description of Changes to Operating Income	Direct Schedule D-4 (IR)
Summary of Revenue Requirements	Direct Schedule D-5 (IR)
Capital Structure and Rate of Return Calculations	Direct Schedule D-6 (IR)
Description of Changes to Capital Structure and Rate of Return	Direct Schedule D-7 (IR)

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E. Comparison of Proposed Test Year to Most Recent General Rate Case

Detailed Rate Base Components	Direct Schedule E-1 (IR)
Description of Changes to Rate Base	Direct Schedule E-2 (IR)
Statement of Operating Income	Direct Schedule E-3 (IR)
Description of Changes to Operating Income	Direct Schedule E-4 (IR)
Summary of Revenue Requirements	Direct Schedule E-5 (IR)

F. Comparison of Proposed Interim Rates to Proposed Test Year

Detailed Rate Base Components	Direct Schedule F-1 (IR)
Description of Changes to Rate Base	Direct Schedule F-2 (IR)
Statement of Operating Income	Direct Schedule F-3 (IR)
Description of Changes to Operating Income	Direct Schedule F-4 (IR)
Summary of Revenue Requirements	Direct Schedule F-5 (IR)

Line No.	Description	Calculation Note	Proposed Interim Rates 2027
		(1)	(2)
1	Total Interim Retail Revenue		$754,017,218
2	Interim Revenue Deficiency		$148,880,924
3	Total Interim Revenue Percent Increase	Line 2 / Line 1	19.75%

Line No.	Description	Calculation Note	Interim Test Year 2027
		(1)	(2)
1	Average Rate Base		$2,626,893,825
2	Operating Income Before AFUDC		$73,580,412
3	AFUDC		$18,881,162
4	Operating Income	Line 2 + Line 3	$92,461,574
5	Rate of Return	Line 4 / Line 1	3.5198%
6	Required Rate of Return		7.5584%
7	Required Operating Income	Line 1 * Line 6	$198,551,143
8	Operating Income Deficiency	Line 7 - Line 4	$106,089,569
9	Gross Revenue Conversion Factor		1.40335
10	Revenue Deficiency	Line 8 * Line 9	$148,880,924
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$754,017,218
12	Required Percent Increase	Line 10 / Line 11	19.75%

Line No.	Description	Interim Test Year 2027
		(1)
1	Plant In Service	
2	Steam	$1,272,894,129
3	Hydro	$207,952,377
4	Wind	$659,828,189
5	Transmission	$1,112,960,023
6	Distribution	$930,744,366
7	General Plant	$311,388,660
8	Intangible Plant	$90,334,735
9	Plant In Service	$4,586,102,478
10		
11	Accumulated Depreciation and Amortization	
12	Steam	($817,476,147)
13	Hydro	($52,361,140)
14	Wind	($244,525,180)
15	Transmission	($322,898,886)
16	Distribution	($387,973,202)
17	General Plant	($125,316,895)
18	Intangible Plant	($74,752,994)
19	Total Accumulated Depreciation and Amortization	($2,025,304,445)
20		
21	Net Plant Before CWIP	
22	Steam	$455,417,982
23	Hydro	$155,591,237
24	Wind	$415,303,009
25	Transmission	$790,061,136
26	Distribution	$542,771,163
27	General Plant	$186,071,765
28	Intangible Plant	$15,581,740
29	Total Net Plant Before CWIP	$2,560,798,033
30	Construction Work in Progress	$242,987,155
31	Utility Plant	$2,803,785,188
32		
33	Working Capital	
34	Fuel Inventory	$19,556,262
35	Materials and Supplies	$56,530,899
36	Prepayments	$21,614,969
37	Cash Working Capital	($38,711,136)
38	Total Working Capital	$58,990,993
39		
40	Additions and Deductions	
41	Asset Retirement Obligation	$0
42	Workers Compensation Deposit	$71,322
43	Unamortized UMWI Transaction Cost	$701,960
44	Customer Advances	($3,666,416)
45	Other Deferred Credits - Hibbard	($281,381)
46	Wind Performance Deposit	($124,424)
47	Accumulated Deferred Income Taxes	($232,583,417)
48	Total Additions and Deductions	($235,882,356)
49		
50	**Total Average Rate Base**	**$2,626,893,825**

Line No.	Description	Interim Test Year 2027
		(1)
1	Operating Revenue	
2	Sales by Rate Class	$742,990,070
3	Dual Fuel	$11,027,148
4	Intersystem Sales	$34,080,750
5	Sales for Resale	$70,222,419
6	Total Revenue from Sales	$858,320,388
7	Other Operating Revenue	$82,982,759
8	Total Operating Revenue	$941,303,147
9		
10	Operating Expenses Before AFUDC	
11	Operation and Maintenance Expenses	
12	Steam Production	($42,496,606)
13	Hydro Production	($5,081,063)
14	Wind Production	($15,824,779)
15	Energy Storage	($6,125)
16	Other Power Supply	($2,231,385)
17	Purchased Power	($215,753,464)
18	Fuel	($128,407,158)
19	Total Production	($409,800,579)
20	Transmission	($76,698,602)
21	Distribution	($32,815,348)
22	Customer Accounting	($7,447,719)
23	Customer Service and Information	($1,503,648)
24	Conservation Improvement Program	($17,145,250)
25	Administrative and General	($87,379,128)
26	Charitable Contributions	($297,773)
27	Interest on Customer Deposits	($2,391,000)
28	Total Operation and Maintenance Expenses	($635,479,046)
29	Depreciation Expense	($181,173,220)
30	Amortization Expense	($9,268,369)
31	Taxes Other Than Income Taxes	($45,912,656)
32	Income Taxes	($209,514)
33	Deferred Income Taxes	$3,487,496
34	Investment Tax Credit	$832,573
35	Total Operating Expenses Before AFUDC	($867,722,735)
36		
37	Operating Income Before AFUDC	$73,580,412
38	Allowance for Funds Used During Construction	$18,881,162
39	**Total Operating Income**	**$92,461,574**

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Unadjusted Test Year 2027	Adjustments	Interim Test Year 2027	Unadjusted Test Year 2027	Adjustments	Interim Test Year 2027
		(1)	(2)	(3)	(4)	(5)	(6)
1	Plant In Service						
2	Steam	$1,801,558,886	($267,709,200)	$1,533,849,686	$1,494,956,234	($222,062,105)	$1,272,894,129
3	Hydro	$251,719,345	$0	$251,719,345	$207,952,377	$0	$207,952,377
4	Wind	$811,472,590	($11,210,478)	$800,262,112	$669,127,169	($9,298,980)	$659,828,189
5	Solar	$196,276,857	($196,276,857)	$0	$159,596,264	($159,596,264)	$0
6	Transmission	$1,472,755,185	($30,417,883)	$1,442,337,302	$1,132,631,171	($19,671,148)	$1,112,960,023
7	Distribution	$1,009,158,201	($4,772,807)	$1,004,385,394	$935,516,128	($4,771,762)	$930,744,366
8	General Plant	$366,799,716	($1,808,142)	$364,991,573	$312,953,818	($1,565,158)	$311,388,660
9	Intangible Plant	$105,885,092	$0	$105,885,092	$90,341,248	($6,513)	$90,334,735
10	Total Plant In Service	$6,015,625,872	($512,195,368)	$5,503,430,504	$5,003,074,407	($416,971,929)	$4,586,102,478
11							
12	Accumulated Depreciation and Amortization						
13	Steam	($932,752,115)	($52,557,453)	($985,309,568)	($773,880,265)	($43,595,882)	($817,476,147)
14	Hydro	($77,178,699)	$13,799,421	($63,379,278)	($63,769,085)	$11,407,945	($52,361,140)
15	Wind	($299,841,250)	$3,194,220	($296,647,030)	($247,174,754)	$2,649,574	($244,525,180)
16	Solar	($1,951,330)	$1,951,330	$0	($1,589,139)	$1,589,139	$0
17	Transmission	($364,345,849)	($53,666,829)	($418,012,679)	($281,329,067)	($41,569,819)	($322,898,886)
18	Distribution	($362,555,237)	($56,115,147)	($418,670,383)	($336,097,146)	($51,876,056)	($387,973,202)
19	General Plant	($152,343,549)	$5,454,414	($146,889,134)	($129,979,640)	$4,662,746	($125,316,895)
20	Intangible Plant	($87,621,088)	$0	($87,621,088)	($74,758,384)	$5,389	($74,752,994)
21	Total Accumulated Depreciation and Amortization	($2,278,589,116)	($137,940,044)	($2,416,529,160)	($1,908,577,480)	($116,726,965)	($2,025,304,445)
22							
23	Net Plant Before CWIP						
24	Steam	$868,806,771	($320,266,654)	$548,540,118	$721,075,968	($265,657,987)	$455,417,982
25	Hyrdo	$174,540,646	$13,799,421	$188,340,068	$144,183,292	$11,407,945	$155,591,237
26	Wind	$511,631,340	($8,016,258)	$503,615,082	$421,952,415	($6,649,406)	$415,303,009
27	Solar	$194,325,528	($194,325,528)	$0	$158,007,126	($158,007,126)	$0
28	Transmission	$1,108,409,335	($84,084,712)	$1,024,324,623	$851,302,103	($61,240,967)	$790,061,136
29	Distribution	$646,602,965	($60,887,954)	$585,715,011	$599,418,981	($56,647,818)	$542,771,163
30	General Plant	$214,456,167	$3,646,272	$218,102,439	$182,974,177	$3,097,588	$186,071,765
31	Intangible Plant	$18,264,005	$0	$18,264,005	$15,582,864	($1,123)	$15,581,740
32	Total Net Plant Before CWIP	$3,737,036,756	($650,135,411)	$3,086,901,345	$3,094,496,927	($533,698,894)	$2,560,798,033
33	Construction Work in Progress	$2,188,887,012	($1,453,387,888)	$735,499,124	$1,393,803,273	($1,150,816,118)	$242,987,155
34	Utility Plant	$5,925,923,768	($2,103,523,299)	$3,822,400,469	$4,488,300,200	($1,684,515,012)	$2,803,785,188
35							
36	Working Capital						
37	Fuel Inventory	$24,256,129	$0	$24,256,129	$19,556,262	$0	$19,556,262
38	Materials and Supplies	$69,111,154	$0	$69,111,154	$56,528,126	$2,773	$56,530,899
39	Prepayments	$197,053,801	($170,828,488)	$26,225,313	$167,337,490	($145,722,522)	$21,614,969
40	Cash Working Capital	($44,824,914)	($1,836,442)	($46,661,356)	($36,610,443)	($2,100,693)	($38,711,136)
41	Total Working Capital	$245,596,170	($172,664,930)	$72,931,240	$206,811,434	($147,820,442)	$58,990,993
42							
43	Additions and Deductions						
44	Asset Retirement Obligation	($353,447,292)	$353,447,292	$0	($293,180,994)	$293,180,994	$0
45	Electric Vehicle Program	$333,070	($333,070)	$0	$308,765	($308,765)	$0
46	Workers Compensation Deposit	$83,599	$0	$83,599	$71,327	($5)	$71,322
47	Unamortized UMWI Transaction Cost	$909,703	$0	$909,703	$701,777	$183	$701,960
48	Customer Advances	($3,666,416)	$0	($3,666,416)	($3,666,416)	$0	($3,666,416)
49	Other Deferred Credits - Hibbard	($339,222)	($0)	($339,222)	($281,381)	($0)	($281,381)
50	Wind Performance Deposit	($150,000)	($0)	($150,000)	($124,423)	($0)	($124,424)
51	Accumulated Deferred Income Taxes	($388,676,941)	$105,700,853	($282,976,088)	($320,718,665)	$88,135,248	($232,583,417)
52	Total Additions and Deductions	($744,953,499)	$458,815,075	($286,138,424)	($616,890,012)	$381,007,656	($235,882,356)
53							
54	**Total Average Rate Base**	**$5,426,566,439**	**($1,817,373,154)**	**$3,609,193,285**	**$4,078,221,623**	**($1,451,327,798)**	**$2,626,893,825**

The adjustments listed below are used to convert from the Unadjusted Test Year budget rate base to the Interim Test Year rate base. A bridge schedule is provided in Direct Schedule B-3(IR) for Minnesota Jurisdiction and B-4(IR) for Total Company.

B-3 (IR) & B-4 (IR) Column		Reference
(2) (3) (4)	**Asset Retirement Obligations (ARO), Cost to Retire, and Decommissioning**	
	Exclude ARO from plant and accumulated depreciation balances, as required in MP's 2008 rate case, Docket No. E015/GR-08-415. Include related cost to retire and decommissioning adjustments to increase accumulated depreciation instead.	Turner Direct, V. A. 1-3.; Vol. 4, Workpaper ADJ-RB-1; Vol. 4, Workpaper ADJ-RB-2;Vol. 4, Workpaper ADJ-RB-3
(5)	**Boswell Unit 3 Environmental Project**	
	Reduce plant and accumulated depreciation balances as required in MP's 2009 rate case, Docket No. E015/GR-09-1151.	Turner Direct, V. A. 4.; Vol. 4, Workpaper ADJ-RB-4
(6)	**Pro Rata Accumulated Deferred Income Tax ("ADIT")**	
	Pro Rata ADIT methodology applies to Interim Test Year 2027, per Commission decision in MP's 2016 rate case, Docket No. E015/GR-16-664).	Turner Direct, V. A. 5.; Vol. 4, Workpaper ADJ-RB-5
(7)	**Prepaid Other Post-Employment Benefits ("OPEB")**	
	Exclude Prepaid OPEB Asset and related ADIT for Interim Rates.	Turner Direct, V.A.6.; Anderson Direct, III; Vol. 4, Workpaper ADJ-RB-6
(8)	**Prepaid Pension**	
	Exclude prepaid pension asset and related ADIT for Interim Rates.	Turner Direct, V.A.7.; Anderson Direct, II; Vol. 4, Workpaper ADJ-RB-7
(9)	**EVSE Project**	
	Remove Electric Vehicle Service Extension deferred costs from rate base in this rate case.	Turner Direct, V.A.8.; Vol. 4, Workpaper ADJ-RB-8
(10)	**EV Make Ready**	
	Remove Electric Vehicle Make Ready (including EV Multi Dwelling Unit ("EV MDU") program capital from rate base in this rate case.	Turner Direct, V.A.9.; Vol. 4, Workpaper ADJ-RB-9
(11)	**EV DCFC Project**	
	Exclude Electric Vehicle DC Fast Charger Project ("EV DCFC Project") capital cost from Interim Test Year.	Turner Direct, V.A.10.; Vol. 4, Workpaper ADJ-RB-10
(12)	**Aircraft Hangar**	
	Net plant balance of corporate aircraft hangar is removed from rate base because MP chose to forego rate recovery of any costs associated with the aircraft.	Turner Direct, V.A.11; Vol. 4, Workpaper ADJ-RB- 11
(13)	**Customer Upgrades**	
	Remove customer-specific upgrade costs from CCOSS.	Turner Direct, V.A.12.; Vol. 4, Workpaper ADJ-RB-12
(14)	**Continuing Cost Recovery Riders**	
	Projects and costs in the test year budget that are included in cost recovery riders after this rate case are removed from rate base to avoid double recovery.	Turner Direct, V.A.13.; Levi Peterson Direct, VI.; Vol. 4, Workpaper ADJ-RB-13
(15)	**Cash Working Capital O&M**	
	Cash working capital is adjusted to reflect the impact of various O&M expense adjustments to the test year budget and tax impacts.	Turner Direct, V.A.15; Vol. 4, Workpaper ADJ-RB-15
(16)	**Changes in Allocations Due to Adjustments (MN Jurisdictional)**	
	The adjustments made in the adjusted versions of class cost-of-service studies may cause changes in allocation factors that have to be accounted for when bridging from an unadjusted to an adjusted CCOSS.	Turner Direct, V.A.16; Vol. 4, Workpaper ADJ-RB-16

Line No.	Description	Unadjusted Test Year 2027	Asset Retirement Obligation	Cost to Retire	Decommissioning	Boswell 3 Environmental Project	Pro Rata ADIT	Prepaid OPEB	Prepaid Pension	EVSE Project
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Plant In Service									
2	Steam	$1,494,956,234	($209,427,796)	$0	$0	($12,634,309)	$0	$0	$0	$0
3	Hydro	$207,952,377	$0	$0	$0	$0	$0	$0	$0	$0
4	Wind	$669,127,169	($9,298,980)	$0	$0	$0	$0	$0	$0	$0
5	Solar	$159,596,264	$0	$0	$0	$0	$0	$0	$0	$0
6	Transmission	$1,132,631,171	$0	$0	$0	$0	$0	$0	$0	$0
7	Distribution	$935,516,128	$0	$0	$0	$0	$0	$0	$0	$0
8	General Plant	$312,953,818	$0	$0	$0	$0	$0	$0	$0	$0
9	Intangible Plant	$90,341,248	$0	$0	$0	$0	$0	$0	$0	$0
10	Total Plant In Service	$5,003,074,407	($218,726,775)	$0	$0	($12,634,309)	$0	$0	$0	$0
11										
12	Accumulated Depreciation and Amortization									
13	Steam	($773,880,265)	$63,316,966	$0	($115,412,210)	$8,499,362	$0	$0	$0	$0
14	Hydro	($63,769,085)	$0	$11,407,945	$0	$0	$0	$0	$0	$0
15	Wind	($247,174,754)	$3,599,865	$0	($950,292)	$0	$0	$0	$0	$0
16	Solar	($1,589,139)	$0	$0	$0	$0	$0	$0	$0	$0
17	Transmission	($281,329,067)	$0	($41,852,632)	$0	$0	$0	$0	$0	$0
18	Distribution	($336,097,146)	$0	($52,730,272)	$0	$0	$0	$0	$0	$0
19	General Plant	($129,979,640)	$0	$3,802,610	$0	$0	$0	$0	$0	$0
20	Intangible Plant	($74,758,384)	$0	$0	$0	$0	$0	$0	$0	$0
21	Total Accumulated Depreciation and Amortization	($1,908,577,480)	$66,916,832	($79,372,349)	($116,362,502)	$8,499,362	$0	$0	$0	$0
22										
23	Net Plant Before CWIP									
24	Steam	$721,075,968	($146,110,829)	$0	($115,412,210)	($4,134,947)	$0	$0	$0	$0
25	Hyrdo	$144,183,292	$0	$11,407,945	$0	$0	$0	$0	$0	$0
26	Wind	$421,952,415	($5,699,114)	$0	($950,292)	$0	$0	$0	$0	$0
27	Solar	$158,007,126	$0	$0	$0	$0	$0	$0	$0	$0
28	Transmission	$851,302,103	$0	($41,852,632)	$0	$0	$0	$0	$0	$0
29	Distribution	$599,418,981	$0	($52,730,272)	$0	$0	$0	$0	$0	$0
30	General Plant	$182,974,177	$0	$3,802,610	$0	$0	$0	$0	$0	$0
31	Intangible Plant	$15,582,864	$0	$0	$0	$0	$0	$0	$0	$0
32	Total Net Plant Before CWIP	$3,094,496,927	($151,809,944)	($79,372,349)	($116,362,502)	($4,134,947)	$0	$0	$0	$0
33	Construction Work in Progress	$1,393,803,273	$0	$0	$0	$0	$0	$0	$0	$0
34	Utility Plant	$4,488,300,200	($151,809,944)	($79,372,349)	($116,362,502)	($4,134,947)	$0	$0	$0	$0
35										
36	Working Capital									
37	Fuel Inventory	$19,556,262	$0	$0	$0	$0	$0	$0	$0	$0
38	Materials and Supplies	$56,528,126	$0	$0	$0	$0	$0	$0	$0	$0
39	Prepayments	$167,337,490	$0	$0	$0	$0	$0	($33,306,293)	($112,434,206)	$0
40	Cash Working Capital	($36,610,443)	$0	$0	$0	$0	$0	$0	$0	$0
41	Total Working Capital	$206,811,434	$0	$0	$0	$0	$0	($33,306,293)	($112,434,206)	$0
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	($293,180,994)	$293,180,994	$0	$0	$0	$0	$0	$0	$0
45	Electric Vehicle Program	$308,765	$0	$0	$0	$0	$0	$0	$0	($308,649)
46	Workers Compensation Deposit	$71,327	$0	$0	$0	$0	$0	$0	$0	$0
47	Unamortized UMWI Transaction Cost	$701,777	$0	$0	$0	$0	$0	$0	$0	$0
48	Customer Advances	($3,666,416)	$0	$0	$0	$0	$0	$0	$0	$0
49	Other Deferred Credits - Hibbard	($281,381)	$0	$0	$0	$0	$0	$0	$0	$0
50	Wind Performance Deposit	($124,423)	$0	$0	$0	$0	$0	$0	$0	$0
51	Accumulated Deferred Income Taxes	($320,718,665)	$14,879,456	$0	$0	$1,111,562	($931,231)	$10,370,160	$34,165,777	$0
52	Total Additions and Deductions	($616,890,012)	$308,060,451	$0	$0	$1,111,562	($931,231)	$10,370,160	$34,165,777	($308,649)
53										
54	**Total Average Rate Base**	**$4,078,221,623**	**$156,250,507**	**($79,372,349)**	**($116,362,502)**	**($3,023,385)**	**($931,231)**	**($22,936,132)**	**($78,268,429)**	**($308,649)**

Line No.	Description	EV Make Ready	EV DCFC	Aircraft Hangar	Customer Upgrades	Continuing Cost Recovery Riders	Cash Working Capital	Changes in Allocations due to Adjustments	Total Adjustments	Interim Test Year 2027
		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	Plant In Service									
2	Steam	$0	$0	$0	$0	$0	$0	$0	($222,062,105)	$1,272,894,129
3	Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$207,952,377
4	Wind	$0	$0	$0	$0	$0	$0	$0	($9,298,980)	$659,828,189
5	Solar	$0	$0	$0	$0	($196,276,857)	$0	$36,680,593	($159,596,264)	$0
6	Transmission	$0	$0	$0	$0	($25,876,245)	$0	$6,205,098	($19,671,147)	$1,112,960,024
7	Distribution	($481,600)	($3,248,147)	$0	$0	($1,043,060)	$0	$1,045	($4,771,762)	$930,744,366
8	General Plant	$0	$0	($1,445,838)	$0	($113,415)	$0	($5,904)	($1,565,157)	$311,388,661
9	Intangible Plant	$0	$0	$0	$0	$0	$0	($6,512)	($6,512)	$90,334,735
10	Total Plant In Service	($481,600)	($3,248,147)	($1,445,838)	$0	($223,309,577)	$0	$42,874,320	($416,971,927)	$4,586,102,480
11										
12	Accumulated Depreciation and Amortization									
13	Steam	$0	$0	$0	$0	$0	$0	$0	($43,595,882)	($817,476,147)
14	Hydro	$0	$0	$0	$0	$0	$0	$0	$11,407,945	($52,361,140)
15	Wind	$0	$0	$0	$0	$0	$0	$0	$2,649,574	($244,525,180)
16	Solar	$0	$0	$0	$0	$1,951,330	$0	($362,191)	$1,589,139	$0
17	Transmission	$0	$0	$0	$0	$390,488	$0	($107,675)	($41,569,819)	($322,898,886)
18	Distribution	$9,838	$301,000	$0	$0	$451,689	$0	$91,689	($51,876,057)	($387,973,203)
19	General Plant	$0	$0	$747,326	$0	$121,245	$0	($8,436)	$4,662,745	($125,316,895)
20	Intangible Plant	$0	$0	$0	$0	$0	$0	$5,389	$5,389	($74,752,995)
21	Total Accumulated Depreciation and Amortization	$9,838	$301,000	$747,326	$0	$2,914,752	$0	($381,225)	($116,726,966)	($2,025,304,446)
22										
23	Net Plant Before CWIP									
24	Steam	$0	$0	$0	$0	$0	$0	$0	($265,657,987)	$455,417,982
25	Hyrdo	$0	$0	$0	$0	$0	$0	$0	$11,407,945	$155,591,237
26	Wind	$0	$0	$0	$0	$0	$0	$0	($6,649,406)	$415,303,009
27	Solar	$0	$0	$0	$0	($194,325,528)	$0	$36,318,402	($158,007,126)	$0
28	Transmission	$0	$0	$0	$0	($25,485,757)	$0	$6,097,423	($61,240,966)	$790,061,137
29	Distribution	($471,762)	($2,947,147)	$0	$0	($591,371)	$0	$92,733	($56,647,819)	$542,771,163
30	General Plant	$0	$0	($698,512)	$0	$7,830	$0	($14,340)	$3,097,588	$186,071,765
31	Intangible Plant	$0	$0	$0	$0	$0	$0	($1,123)	($1,123)	$15,581,740
32	Total Net Plant Before CWIP	($471,762)	($2,947,147)	($698,512)	$0	($220,394,826)	$0	$42,493,095	($533,698,893)	$2,560,798,034
33	Construction Work in Progress	$0	$0	$0	$0	($1,452,107,427)	$0	$301,291,308	($1,150,816,119)	$242,987,154
34	Utility Plant	($471,762)	($2,947,147)	($698,512)	$0	($1,672,502,252)	$0	$343,784,403	($1,684,515,012)	$2,803,785,188
35										
36	Working Capital									
37	Fuel Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$19,556,262
38	Materials and Supplies	$0	$0	$0	$0	$0	$0	$2,773	$2,773	$56,530,899
39	Prepayments	$0	$0	$0	$0	$0	$0	$17,978	($145,722,521)	$21,614,969
40	Cash Working Capital	$0	$0	$0	$0	$0	($2,096,370)	($4,322)	($2,100,692)	($38,711,135)
41	Total Working Capital	$0	$0	$0	$0	$0	($2,096,370)	$16,429	($147,820,440)	$58,990,995
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	$0	$0	$0	$0	$0	$0	$0	$293,180,994	$0
45	Electric Vehicle Program	$0	$0	$0	$0	$0	$0	($115)	($308,765)	$0
46	Workers Compensation Deposit	$0	$0	$0	$0	$0	$0	($5)	($5)	$71,322
47	Unamortized UMWI Transaction Cost	$0	$0	$0	$0	$0	$0	$183	$183	$701,960
48	Customer Advances	$0	$0	$0	$0	$0	$0	$0	$0	($3,666,416)
49	Other Deferred Credits - Hibbard	$0	$0	$0	$0	$0	$0	$0	$0	($281,381)
50	Wind Performance Deposit	$0	$0	$0	$0	$0	$0	$0	$0	($124,423)
51	Accumulated Deferred Income Taxes	$2,737	$133,891	($15,689)	$0	$35,087,152	$0	($6,668,568)	$88,135,248	($232,583,417)
52	Total Additions and Deductions	$2,737	$133,891	($15,689)	$0	$35,087,152	$0	($6,668,505)	$381,007,655	($235,882,356)
53										
54	**Total Average Rate Base**	**($469,025)**	**($2,813,256)**	**($714,201)**	**$0**	**($1,637,415,101)**	**($2,096,370)**	**$337,132,327**	**($1,451,327,797)**	**$2,626,893,827**

Line No.	Description	Unadjusted Test Year 2027	Asset Retirement Obligation	Cost to Retire	Decommissioning	Boswell 3 Environmental Project	Pro Rata ADIT	Prepaid OPEB	Prepaid Pension	EVSE Project
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Plant In Service									
2	Steam	$1,801,558,886	($252,477,782)	$0	$0	($15,231,418)	$0	$0	$0	$0
3	Hydro	$251,719,345	$0	$0	$0	$0	$0	$0	$0	$0
4	Wind	$811,472,590	($11,210,478)	$0	$0	$0	$0	$0	$0	$0
5	Solar	$196,276,857	$0	$0	$0	$0	$0	$0	$0	$0
6	Transmission	$1,472,755,185	$0	$0	$0	$0	$0	$0	$0	$0
7	Distribution	$1,009,158,201	$0	$0	$0	$0	$0	$0	$0	$0
8	General Plant	$366,799,716	$0	$0	$0	$0	$0	$0	$0	$0
9	Intangible Plant	$105,885,092	$0	$0	$0	$0	$0	$0	$0	$0
10	Total Plant In Service	$6,015,625,872	($263,688,261)	$0	$0	($15,231,418)	$0	$0	$0	$0
11										
12	Accumulated Depreciation and Amortization									
13	Steam	($932,752,115)	$76,332,405	$0	($139,136,349)	$10,246,491	$0	$0	$0	$0
14	Hydro	($77,178,699)	$0	$13,799,421	$0	$0	$0	$0	$0	$0
15	Wind	($299,841,250)	$4,339,854	$0	($1,145,634)	$0	$0	$0	$0	$0
16	Solar	($1,951,330)	$0	$0	$0	$0	$0	$0	$0	$0
17	Transmission	($364,345,849)	$0	($54,105,640)	$0	$0	$0	$0	$0	$0
18	Distribution	($362,555,237)	$0	($56,902,268)	$0	$0	$0	$0	$0	$0
19	General Plant	($152,343,549)	$0	$4,457,197	$0	$0	$0	$0	$0	$0
20	Intangible Plant	($87,621,088)	$0	$0	$0	$0	$0	$0	$0	$0
21	Total Accumulated Depreciation and Amortization	($2,278,589,116)	$80,672,259	($92,751,289)	($140,281,983)	$10,246,491	$0	$0	$0	$0
22										
23	Net Plant Before CWIP									
24	Steam	$868,806,771	($176,145,378)	$0	($139,136,349)	($4,984,927)	$0	$0	$0	$0
25	Hyrdo	$174,540,646	$0	$13,799,421	$0	$0	$0	$0	$0	$0
26	Wind	$511,631,340	($6,870,624)	$0	($1,145,634)	$0	$0	$0	$0	$0
27	Solar	$194,325,528	$0	$0	$0	$0	$0	$0	$0	$0
28	Transmission	$1,108,409,335	$0	($54,105,640)	$0	$0	$0	$0	$0	$0
29	Distribution	$646,602,965	$0	($56,902,268)	$0	$0	$0	$0	$0	$0
30	General Plant	$214,456,167	$0	$4,457,197	$0	$0	$0	$0	$0	$0
31	Intangible Plant	$18,264,005	$0	$0	$0	$0	$0	$0	$0	$0
32	Total Net Plant Before CWIP	$3,737,036,756	($183,016,002)	($92,751,289)	($140,281,983)	($4,984,927)	$0	$0	$0	$0
33	Construction Work in Progress	$2,188,887,012	$0	$0	$0	$0	$0	$0	$0	$0
34	Utility Plant	$5,925,923,768	($183,016,002)	($92,751,289)	($140,281,983)	($4,984,927)	$0	$0	$0	$0
35										
36	Working Capital									
37	Fuel Inventory	$24,256,129	$0	$0	$0	$0	$0	$0	$0	$0
38	Materials and Supplies	$69,111,154	$0	$0	$0	$0	$0	$0	$0	$0
39	Prepayments	$197,053,801	$0	$0	$0	$0	$0	($39,039,688)	($131,788,800)	$0
40	Cash Working Capital	($44,824,914)	$0	$0	$0	$0	$0	$0	$0	$0
41	Total Working Capital	$245,596,170	$0	$0	$0	$0	$0	($39,039,688)	($131,788,800)	$0
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	($353,447,292)	$353,447,292	$0	$0	$0	$0	$0	$0	$0
45	Electric Vehicle Program	$333,070	$0	$0	$0	$0	$0	$0	$0	($333,070)
46	Workers Compensation Deposit	$83,599	$0	$0	$0	$0	$0	$0	$0	$0
47	Unamortized UMWI Transaction Cost	$909,703	$0	$0	$0	$0	$0	$0	$0	$0
48	Customer Advances	($3,666,416)	$0	$0	$0	$0	$0	$0	$0	$0
49	Other Deferred Credits - Hibbard	($339,222)	$0	$0	$0	$0	$0	$0	$0	$0
50	Wind Performance Deposit	($150,000)	$0	$0	$0	$0	$0	$0	$0	$0
51	Accumulated Deferred Income Taxes	($388,676,941)	$17,855,378	$0	$0	$1,340,054	($1,120,858)	$12,188,613	$40,156,893	$0
52	Total Additions and Deductions	($744,953,499)	$371,302,669	$0	$0	$1,340,054	($1,120,858)	$12,188,613	$40,156,893	($333,070)
53										
54	**Total Average Rate Base**	**$5,426,566,439**	**$188,286,667**	**($92,751,289)**	**($140,281,983)**	**($3,644,873)**	**($1,120,858)**	**($26,851,076)**	**($91,631,908)**	**($333,070)**

Line No.	Description	EV Make Ready	EV DCFC	Aircraft Hangar	Customer Upgrades	Continuing Cost Recovery Riders	Cash Working Capital	Changes in Allocations due to Adjustments	Total Adjustments	Interim Test Year 2027
		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	Plant In Service									
2	Steam	$0	$0	$0	$0	$0	$0	$0	($267,709,200)	$1,533,849,686
3	Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$251,719,345
4	Wind	$0	$0	$0	$0	$0	$0	$0	($11,210,478)	$800,262,112
5	Solar	$0	$0	$0	$0	($196,276,857)	$0	$0	($196,276,857)	$0
6	Transmission	$0	$0	$0	($4,541,637)	($25,876,245)	$0	$0	($30,417,882)	$1,442,337,303
7	Distribution	($481,600)	($3,248,147)	$0	$0	($1,043,060)	$0	$0	($4,772,807)	$1,004,385,394
8	General Plant	$0	$0	($1,694,727)	$0	($113,415)	$0	$0	($1,808,142)	$364,991,573
9	Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$105,885,092
10	Total Plant In Service	($481,600)	($3,248,147)	($1,694,727)	($4,541,637)	($223,309,577)	$0	$0	($512,195,367)	$5,503,430,505
11										
12	Accumulated Depreciation and Amortization									
13	Steam	$0	$0	$0	$0	$0	$0	$0	($52,557,453)	($985,309,568)
14	Hydro	$0	$0	$0	$0	$0	$0	$0	$13,799,421	($63,379,278)
15	Wind	$0	$0	$0	$0	$0	$0	$0	$3,194,220	($296,647,030)
16	Solar	$0	$0	$0	$0	$1,951,330	$0	$0	$1,951,330	$0
17	Transmission	$0	$0	$0	$48,323	$390,488	$0	$0	($53,666,829)	($418,012,679)
18	Distribution	$10,616	$324,815	$0	$0	$451,689	$0	$0	($56,115,148)	($418,670,384)
19	General Plant	$0	$0	$875,972	$0	$121,245	$0	$0	$5,454,414	($146,889,134)
20	Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	($87,621,088)
21	Total Accumulated Depreciation and Amortization	$10,616	$324,815	$875,972	$48,323	$2,914,752	$0	$0	($137,940,045)	($2,416,529,161)
22										
23	Net Plant Before CWIP									
24	Steam	$0	$0	$0	$0	$0	$0	$0	($320,266,654)	$548,540,118
25	Hyrdo	$0	$0	$0	$0	$0	$0	$0	$13,799,421	$188,340,068
26	Wind	$0	$0	$0	$0	$0	$0	$0	($8,016,258)	$503,615,082
27	Solar	$0	$0	$0	$0	($194,325,528)	$0	$0	($194,325,528)	$0
28	Transmission	$0	$0	$0	($4,493,314)	($25,485,757)	$0	$0	($84,084,711)	$1,024,324,624
29	Distribution	($470,984)	($2,923,332)	$0	$0	($591,371)	$0	$0	($60,887,955)	$585,715,010
30	General Plant	$0	$0	($818,755)	$0	$7,830	$0	$0	$3,646,272	$218,102,439
31	Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$18,264,005
32	Total Net Plant Before CWIP	($470,984)	($2,923,332)	($818,755)	($4,493,314)	($220,394,826)	$0	$0	($650,135,412)	$3,086,901,344
33	Construction Work in Progress	$0	$0	$0	($1,280,461)	($1,452,107,427)	$0	$0	($1,453,387,888)	$735,499,124
34	Utility Plant	($470,984)	($2,923,332)	($818,755)	($5,773,775)	($1,672,502,252)	$0	$0	($2,103,523,300)	$3,822,400,469
35										
36	Working Capital									
37	Fuel Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$24,256,129
38	Materials and Supplies	$0	$0	$0	$0	$0	$0	$0	$0	$69,111,154
39	Prepayments	$0	$0	$0	$0	$0	$0	$0	($170,828,488)	$26,225,313
40	Cash Working Capital	$0	$0	$0	$0	$0	($1,836,442)	$0	($1,836,442)	($46,661,356)
41	Total Working Capital	$0	$0	$0	$0	$0	($1,836,442)	$0	($172,664,930)	$72,931,240
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	$0	$0	$0	$0	$0	$0	$0	$353,447,292	$0
45	Electric Vehicle Program	$0	$0	$0	$0	$0	$0	$0	($333,070)	$0
46	Workers Compensation Deposit	$0	$0	$0	$0	$0	$0	$0	$0	$83,599
47	Unamortized UMWI Transaction Cost	$0	$0	$0	$0	$0	$0	$0	$0	$909,703
48	Customer Advances	$0	$0	$0	$0	$0	$0	$0	$0	($3,666,416)
49	Other Deferred Credits - Hibbard	$0	$0	$0	$0	$0	$0	$0	$0	($339,222)
50	Wind Performance Deposit	$0	$0	$0	$0	$0	$0	$0	$0	($150,000)
51	Accumulated Deferred Income Taxes	$2,953	$144,485	($18,389)	$64,573	$35,087,152	$0	$0	$105,700,853	($282,976,088)
52	Total Additions and Deductions	$2,953	$144,485	($18,389)	$64,573	$35,087,152	$0	$0	$458,815,075	($286,138,424)
53										
54	**Total Average Rate Base**	**($468,031)**	**($2,778,847)**	**($837,144)**	**($5,709,202)**	**($1,637,415,101)**	**($1,836,442)**	**$0**	**($1,817,373,155)**	**$3,609,193,284**

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Unadjusted Test Year 2027	Adjustments	Interim Test Year 2027	Unadjusted Test Year 2027	Adjustments	Interim Test Year 2027
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$915,974,170	($2,420,306)	$913,553,864	$745,410,376	($2,420,306)	$742,990,070
3	Dual Fuel	$11,177,841	($150,692)	$11,027,148	$11,177,841	($150,692)	$11,027,148
4	Intersystem Sales	$42,189,878	$0	$42,189,878	$34,080,750	$0	$34,080,750
5	LP Demand Response	($3,655,110)	$3,655,110	$0	($3,655,110)	$3,655,110	$0
6	Sales for Resale	$89,695,853	($2,681,761)	$87,014,092	$72,446,913	($2,224,494)	$70,222,419
7	Total Revenue from Sales	$1,055,382,631	($1,597,650)	$1,053,784,981	$859,460,770	($1,140,382)	$858,320,388
8	Other Operating Revenue	$308,219,867	($161,239,860)	$146,980,007	$240,625,746	($157,642,987)	$82,982,759
9	Total Operating Revenue	$1,363,602,498	($162,837,510)	$1,200,764,988	$1,100,086,516	($158,783,369)	$941,303,147
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($51,880,866)	$0	($51,880,866)	($42,496,606)	$0	($42,496,606)
14	Hydro Production	($6,230,280)	$0	($6,230,280)	($5,081,063)	$0	($5,081,063)
15	Wind Production	($19,077,721)	$0	($19,077,721)	($15,824,779)	$0	($15,824,779)
16	Solar Production	($2,003,797)	$2,003,797	$0	($1,662,130)	$1,662,130	$0
17	Energy Storage	($7,384)	$0	($7,384)	($6,125)	$0	($6,125)
18	Other Power Supply	($2,690,068)	$0	($2,690,068)	($2,231,385)	$0	($2,231,385)
19	Purchased Power	($267,248,859)	$276,534	($266,972,325)	($215,982,847)	$229,382	($215,753,464)
20	Fuel	($159,266,667)	$0	($159,266,667)	($128,407,158)	$0	($128,407,158)
21	Total Production	($508,405,642)	$2,280,331	($506,125,311)	($411,692,091)	$1,891,512	($409,800,579)
22	Transmission	($135,439,181)	$35,563,181	($99,876,001)	($104,113,249)	$27,414,646	($76,698,602)
23	Distribution	($35,629,445)	$52,296	($35,577,149)	($32,877,486)	$62,138	($32,815,348)
24	Customer Accounting	($7,478,334)	$0	($7,478,334)	($7,447,719)	$0	($7,447,719)
25	Customer Service and Information	($1,956,386)	$449,417	($1,506,969)	($1,952,074)	$448,426	($1,503,648)
26	Conservation Improvement Program	($14,965,248)	($2,180,002)	($17,145,250)	($14,965,248)	($2,180,002)	($17,145,250)
27	Administrative and General	($115,881,961)	$13,294,975	($102,586,986)	($98,448,647)	$11,069,520	($87,379,128)
28	Charitable Contributions	($905,024)	$555,992	($349,032)	($772,167)	$474,395	($297,773)
29	Interest on Customer Deposits	($2,391,000)	$0	($2,391,000)	($2,391,000)	$0	($2,391,000)
30	Total Operation and Maintenance Expenses	($823,052,221)	$50,016,191	($773,036,031)	($674,659,681)	$39,180,635	($635,479,046)
31	Depreciation Expense	($221,827,035)	$5,631,291	($216,195,744)	($185,708,859)	$4,535,639	($181,173,220)
32	Amortization Expense	($12,431,698)	$1,601,633	($10,830,064)	($10,597,667)	$1,329,298	($9,268,369)
33	Taxes Other Than Income Taxes	($56,727,271)	$1,221,440	($55,505,831)	($46,857,121)	$944,465	($45,912,656)
34	Income Taxes	($31,605,772)	$17,231,451	($14,374,321)	($22,481,794)	$22,272,280	($209,514)
35	Deferred Income Taxes	$4,469,922	($156,721)	$4,313,201	$3,617,205	($129,708)	$3,487,496
36	Investment Tax Credit	$1,006,665	$0	$1,006,665	$832,570	$2	$832,573
37	Total Operating Expenses Before AFUDC	($1,140,167,411)	$75,545,285	($1,064,622,126)	($935,855,346)	$68,132,611	($867,722,735)
38							
39	Operating Income Before AFUDC	$223,435,087	($87,292,225)	$136,142,862	$164,231,170	($90,650,759)	$73,580,412
40	Allowance for Funds Used During Construction	$27,934,655	$0	$27,934,655	$18,347,154	$534,008	$18,881,162
41	**Total Operating Income**	**$251,369,742**	**($87,292,225)**	**$164,077,517**	**$182,578,324**	**($90,116,750)**	**$92,461,574**

The adjustments listed below are used to convert from the Unadjusted Test Year budget operating income to the Interim Test Year operating income. A bridge schedule is provided in Direct Schedule B-7(IR) for Minnesota Jurisdiction and Direct Schedule B-8(IR) for Total Company.

B-7 (IR) & B-8 (IR) Column		Reference
(2)	**Advertising Expense**	
	Consistent with Commission decision in MP's 2016 rate case, exclude portion of test year budgeted advertising expense that doesn't qualify for rate recovery based on Commission's Statement of Policy on Advertising.	Turner Direct, V.B.1.; Vol. 3, Sched. G-1; Vol. 4, Workpaper ADJ-IS-1
(3)	**Charitable Contributions**	
	Consistent with Commission decision in MP's 2016 rate case, exclude 50 percent of average actual expense for qualified charitable contributions in previous three years.	Turner Direct, V.B.2.; Vol. 3, Sched. G-2; Vol. 4, Workpaper ADJ-IS-2
(4)	**Economic Development**	
	Exclude 50 percent of test year Economic and Community Development expense, consistent with Commission decisions in MP's 2008, 2009, 2016, 2021 and 2023 rate cases.	Turner Direct, V.B.3; Vol. 3, Sched. G-5; Vol. 4, Workpaper ADJ-IS-3
(5)	**Organizational Dues**	
	Excluded non-allowable legislative lobbying dues, in compliance with Commission's Statement of Policy on Organization Dues and treatment in MP's 2016 rate case.	Turner Direct, V.B.4.; Vol. 4, Workpaper ADJ-IS-4
(6)	**Employee Expenses**	
	Excluded certain categories of travel and lodging, food and beverage, gift, social club dues, recreation, and entertainment expenses. Excluded lobbying-related expenses that were included in employee expense accounts, beyond the majority of lobbying expenses that are recorded in separate non-regulated expense accounts.	Turner Direct, V.B.5.; Bleicher Direct IV; Vol. 3, Sched. H-1; Vol. 4, Workpaper ADJ-IS-5
(7) (8)	**Asset Retirement Obligation (ARO) and Decommissioning**	
	Exclude ARO from depreciation, amortization expense as required in MP's 2008 rate case, Docket No. E015/GR-08-415, and include decommissioning expense instead.	Turner Direct, V.B.6-7.; Vol. 4, Workpaper ADJ-IS-6, ADJ-IS-7
(9)	**Boswell Unit 3 Environmental Project**	
	Remove a portion of Boswell Unit 3 and Common depreciation expense related to 2017, as ordered in MP's 2018 Remaining Life Depreciation Petition, Docket No.	Turner Direct, V.B.8.; Vol. 4, Workpaper ADJ-IS-8
(10)	**Conservation Expense**	
	Conservation expense is adjusted to remove the amount in the test year budget and instead include projected test year expenditures based on MP's 2027-2029 Energy Conservation and Optimization (ECO) Triennial Plan. Docket No. E015/CIP-26-91.	Turner Direct, V.B.9.; Vol. 4, Workpaper ADJ-IS-9
(11)	**Years of Service Awards**	
	Exclude Years of Service Awards for Interim Test Year consistent with MP's 2021 and 2023 rate cases.	Turner Direct, V.B.10.; Chan Direct, V.B.; Vol. 4, Workpaper ADJ-IS-10
(12)	**Incentive Compensation**	
	Excludes Annual Incentive Plan (AIP) greater than 20 percent of individual base pay, consistent with prior Commission orders. Also excludes legacy Long-Term Incentive Plan (LTIP), Supplemental Executive Retirement Plan (SERP), Executive Deferral Plan, Executive Investment Plan, and Legacy Employment Agreements.	Turner Direct, V.B.11.; Chan Direct, III.B.; Vol. 4, Workpaper ADJ-IS-11
(13)	**EV DCFC Project**	
	Exclude revenue, depreciation and O&M expense of Electric Vehicle DC Fast Charger Project ("EV DCFC Project") for Interim Rates.	Turner Direct, V.B.13.; Vol. 4, Workpaper ADJ-IS-13
(14)	**EVMake Ready**	
	Remove Electric Vehicle Make Ready (including EV Multi Dwelling Unit ("EV MDU") program) costs from operating income from Interim Test Year.	Turner Direct, V.B.14.; Vol. 4, Workpaper ADJ-IS-14
(15)	**Customer Upgrades**	
	Remove customer-specific upgrade cost from CCOSS.	Turner Direct, V.B.15.; Vol. 4, Workpaper ADJ-IS-15
(16)	**Aircraft Hangar**	
	Remove depreciation expense for corporate aircraft hangar because MP chose to forego rate recovery of any costs associated with the aircraft.	Turner Direct, V.B.16.; Vol. 4, Workpaper ADJ-IS-16

(17)	**Customer Affordability of Residential Electricity ("CARE") Rider**	
	CARE Rider discounts and surcharge collections are accumulated in a tracker and adjusted as necessary between rate cases in a separate docket. Therefore, the Residential class discount and the Affordability Surcharge revenue from all customer classes is removed from retail Sales by Rate Class for cost-of-service purposes.	Turner Direct, V.B.17.; Vol. 4, Workpaper ADJ-IS-17
(18)	**CIP Incentive**	
	Remove CIP incentive from rate case revenue because the CIP incentive is intended to provide an incentive to the Company for conservation program performance.	Turner Direct, V.B.18.; Vol. 4, Workpaper ADJ-IS-18
(19)	**CIP Carrying Charge**	
	Remove CIP tracker carrying charge from rate case revenue because the CIP tracker provides a return on outstanding tracker balances.	Turner Direct, V.B.19.; Vol. 4, Workpaper ADJ-IS-19
(20)	**CPA Incentive**	
	Adjustments for timing of when CIP/CPA revenue is collected through customer billings vs. recorded as revenue on MP's books.	Turner Direct, V.B.20.; Vol. 4, Workpaper ADJ-IS-20
(21)	**CPA**	
	Total CPA revenue is removed from rate case because the CPA Rider will continue on customer bills outside of base rates.	Turner Direct, V.B.21.; Vol. 4, Workpaper ADJ-IS-21
(22)	**Conservation Cost Recovery Charge (CCRC)**	
	CCRC credit amount for related to CIP-exempt customers included in the test year budget is removed from revenue because the CCRC credit amount is contained in the CIP tracker and corresponding rates are adjusted separately from base rates.	Turner Direct, V.B.22.; Vol. 4, Workpaper ADJ-IS-22
(23)	**Capacity Revenue and Expense**	
	Remove capacity exense and revenue from rate case consistent with Commission order in the Company's 2023 rate case, allowing cost recovery of these revenues and expenses throught the Rider for Capacity and Expense Adjustmnet.	Turner Direct, V.B.23; Vol. 4, Workpaper ADJ-IS-23
(24)	**Reduce Employee Count**	
	Reduce budgeted staffing levels in Interim Test Year.	Turner Direct, V.B.24; Chan Direct, IV.F.; Vol. 4, Workpaper ADJ-IS-24
(25)	**Revenue Budget Corrections**	
	Increase budgeted Sales by Rate Class to align CCOSS and Direct Schedule E-1 and E-2.	Turner Direct, V.B.25; Vol. 4, Workpaper ADJ-IS-25
(26)	**Continuing Cost Recovery Riders**	
	Revenue, Other Operating Revenue, O&M expenses, depreciation expense, and taxes associated with projects in the test year budget that will continue to be recovered in cost recovery riders after this rate case are removed to avoid double	Turner Direct, V.B.26.; Levi Peterson Direct, VI.; Vol. 4, Workpaper ADJ-IS-26
(27)	**Rate Case Expense**	
	Test year budgeted retail rate case expenses proposed to be amortized over two years.	Turner Direct, V.B.27.; Vol 4, Workpaper ADJ-IS-27
(28)	**LTIP**	
	Remove Redesigned LTIP cost from Interim Test Year.	Turner Direct, V.B.28.; Chan Direct, IV. D.; Vol. 4, Workpaper ADJ-IS-28
(29)	**Interest Synchronization**	
	Adjustment for interest expense deduction for income tax purposes to equal the weighted cost of debt multiplied by average rate base. Updated whenever there is a change in rate base, weighted cost of debt, or operating income.	Turner Direct, V.B.30.; Vol. 4, Workpaper ADJ-IS-30
(30)	**Changes in Allocations Due to Adjustments (MN Jurisdictional)**	
	Adjustments to account for changes in allocation factors resulting from other adjustments accounted for when bridging from an unadjusted to an adjusted CCOSS	Turner Direct, V.B.31; Vol. 4, Workpaper ADJ-RB-31

Line No.	Description	Unadjusted Test Year 2027	Advertising Expense	Charitable Contributions	Economic Development	Organizational Dues	Employee Expenses	Asset Retirement Obligation
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Operating Revenue							
2	Sales by Rate Class	$745,410,376	$0	$0	$0	$0	$0	$0
3	Dual Fuel	$11,177,841	$0	$0	$0	$0	$0	$0
4	Intersystem Sales	$34,080,750	$0	$0	$0	$0	$0	$0
5	LP Demand Response	($3,655,110)	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$72,446,913	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$859,460,770	$0	$0	$0	$0	$0	$0
8	Other Operating Revenue	$240,625,746	$0	$0	$0	$0	$0	$0
9	Total Operating Revenue	$1,100,086,516	$0	$0	$0	$0	$0	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	($42,496,606)	$0	$0	$0	$0	$0	$0
14	Hydro Production	($5,081,063)	$0	$0	$0	$0	$0	$0
15	Wind Production	($15,824,779)	$0	$0	$0	$0	$0	$0
16	Solar Production	($1,662,130)	$0	$0	$0	$0	$0	$0
17	Energy Storage	($6,125)	$0	$0	$0	$0	$0	$0
18	Other Power Supply	($2,231,385)	$0	$0	$0	$0	$0	$0
19	Purchased Power	($215,982,847)	$0	$0	$0	$0	$0	$0
20	Fuel	($128,407,158)	$0	$0	$0	$0	$0	$0
21	Total Production	($411,692,091)	$0	$0	$0	$0	$0	$0
22	Transmission	($104,113,249)	$0	$0	$0	$0	$0	$0
23	Distribution	($32,877,486)	$4,602	$0	$0	$0	$0	$0
24	Customer Accounting	($7,447,719)	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	($1,952,074)	$2,836	$0	$83,066	$0	$0	$0
26	Conservation Improvement Program	($14,965,248)	$0	$0	$0	$0	$0	$0
27	Administrative and General	($98,448,647)	$408,001	$0	$364,169	$115,376	$638,010	$0
28	Charitable Contributions	($772,167)	$0	$474,339	$0	$0	$0	$0
29	Interest on Customer Deposits	($2,391,000)	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	($674,659,681)	$415,438	$474,339	$447,235	$115,376	$638,010	$0
31	Depreciation Expense	($185,708,859)	$0	$0	$0	$0	$0	$1,790,134
32	Amortization Expense	($10,597,667)	$0	$0	$0	$0	$0	$1,328,539
33	Taxes Other Than Income Taxes	($46,857,121)	$0	$0	$0	$0	$0	$0
34	Income Taxes	($22,481,794)	($119,405)	($136,334)	($128,544)	($33,161)	($183,377)	($896,369)
35	Deferred Income Taxes	$3,617,205	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$832,570	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($935,855,346)	$296,033	$338,004	$318,691	$82,215	$454,633	$2,222,304
38								
39	Operating Income Before AFUDC	$164,231,170	$296,033	$338,004	$318,691	$82,215	$454,633	$2,222,304
40	Allowance for Funds Used During Construction	$18,347,154	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$182,578,324**	**$296,033**	**$338,004**	**$318,691**	**$82,215**	**$454,633**	**$2,222,304**

Line No.	Description	Decommissioning	Boswell 3 Environmental Project	Conservation Expense	Years of Service Awards	Incentive Compensation	EV DCFC	EV Make Ready
		(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Operating Revenue							
2	Sales by Rate Class	$0	$0	$0	$0	$0	($74,377)	$0
3	Dual Fuel	$0	$0	$0	$0	$0	$0	$0
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$0	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$0	$0	$0	$0	$0	($74,377)	$0
8	Other Operating Revenue	$0	$0	$0	$0	$0	($152,389)	$0
9	Total Operating Revenue	$0	$0	$0	$0	$0	($226,766)	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$0	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$0	$0	$0	$0	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$0	$0	$0	$0	$0	$0
22	Transmission	$0	$0	$0	$0	$0	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$43,529	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$0	$0	$0
26	Conservation Improvement Program	$0	$0	($2,180,002)	$0	$0	$0	$0
27	Administrative and General	$0	$0	$0	$37,122	$4,592,727	$0	$0
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$0	($2,180,002)	$37,122	$4,592,727	$43,529	$0
31	Depreciation Expense	($1,788,508)	$488,861	$0	$0	$0	$301,000	$11,916
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
34	Income Taxes	$514,053	($140,508)	$626,576	($10,670)	($1,320,042)	($33,848)	($3,425)
35	Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($1,274,455)	$348,352	($1,553,426)	$26,452	$3,272,686	$310,682	$8,491
38								
39	Operating Income Before AFUDC	($1,274,455)	$348,352	($1,553,426)	$26,452	$3,272,686	$83,916	$8,491
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**($1,274,455)**	**$348,352**	**($1,553,426)**	**$26,452**	**$3,272,686**	**$83,916**	**$8,491**

Line No.	Description	Customer Upgrades	Aircraft Hangar	CARE	CIP Incentive	CIP Carrying Charge	CPA Incentive	CPA
		(15)	(16)	(17)	(18)	(19)	(20)	(21)
1	Operating Revenue							
2	Sales by Rate Class	$0	$0	($0)	$0	$0	$2,615,524	($5,435,611)
3	Dual Fuel	$0	$0	$0	$0	$0	$95,631	($204,881)
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$0	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$0	$0	($0)	$0	$0	$2,711,154	($5,640,493)
8	Other Operating Revenue	$0	$0	$0	($2,969,622)	($41,519)	$0	$0
9	Total Operating Revenue	$0	$0	($0)	($2,969,622)	($41,519)	$2,711,154	($5,640,493)
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$0	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$0	$0	$0	$0	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$0	$0	$0	$0	$0	$0
22	Transmission	$0	$0	$0	$0	$0	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$0	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$0	$0	$0
26	Conservation Improvement Program	$0	$0	$0	$0	$0	$0	$0
27	Administrative and General	$0	$0	$0	$0	$0	$0	$0
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$0	$0	$0	$0	$0	$0
31	Depreciation Expense	$0	$59,396	$0	$0	$0	$0	$0
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
34	Income Taxes	$0	($17,071)	$0	$853,529	$11,933	($779,240)	$1,621,190
35	Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	$0	$42,324	$0	$853,529	$11,933	($779,240)	$1,621,190
38								
39	Operating Income Before AFUDC	$0	$42,324	($0)	($2,116,093)	($29,586)	$1,931,914	($4,019,302)
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$0**	**$42,324**	**($0)**	**($2,116,093)**	**($29,586)**	**$1,931,914**	**($4,019,302)**

Line No.	Description	CCRC	Capacity Revenue and Expense	Reduce Employee Count	Revenue Budget Corrections	Continuing Cost Recovery Riders	Rate Case Expense	LTIP
		(22)	(23)	(24)	(25)	(26)	(27)	(28)
1	Operating Revenue							
2	Sales by Rate Class	$1,323,647	($129,436)	$0	$409,675	($1,112,650)	$0	$0
3	Dual Fuel	$0	($15,565)	$0	$0	($25,878)	$0	$0
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$3,655,110	$0	$0	$0	$0	$0
6	Sales for Resale	$0	($2,681,761)	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$1,323,647	$828,348	$0	$409,675	($1,138,528)	$0	$0
8	Other Operating Revenue	$0	$0	$0	$0	($158,064,273)	$0	$0
9	Total Operating Revenue	$1,323,647	$828,348	$0	$409,675	($159,202,801)	$0	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$2,003,797	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$68,400	$0	$0	$208,134	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$68,400	$0	$0	$2,211,931	$0	$0
22	Transmission	$0	$0	$0	$0	$35,563,181	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$0	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$363,325	$0	$0
26	Conservation Improvement Program	$0	$0	$0	$0	$0	$0	$0
27	Administrative and General	$0	$0	$4,265,697	$0	$0	($1,756,956)	$2,420,292
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$68,400	$4,265,697	$0	$38,138,437	($1,756,956)	$2,420,292
31	Depreciation Expense	$0	$0	$0	$0	$4,536,040	$0	$0
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$1,221,440	$0	$0
34	Income Taxes	($380,443)	($257,743)	($1,226,047)	($117,749)	$33,141,504	$504,984	($695,640)
35	Deferred Income Taxes	$0	$0	$0	$0	($156,721)	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($380,443)	($189,343)	$3,039,650	($117,749)	$76,880,701	($1,251,972)	$1,724,652
38								
39	Operating Income Before AFUDC	$943,204	$639,004	$3,039,650	$291,926	($82,322,100)	($1,251,972)	$1,724,652
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$943,204**	**$639,004**	**$3,039,650**	**$291,926**	**($82,322,100)**	**($1,251,972)**	**$1,724,652**

Line No.	Description	Interest Synchronization	Changes in Allocations due to Adjustments	Total Adjustments	Interim Test Year 2027
		(29)	(30)	(31)	(32)
1	Operating Revenue				
2	Sales by Rate Class	$0	($17,074)	($2,420,303)	$742,990,073
3	Dual Fuel	$0	$0	($150,693)	$11,027,147
4	Intersystem Sales	$0	$0	$0	$34,080,750
5	LP Demand Response	$0	$0	$3,655,110	$0
6	Sales for Resale	$0	$457,267	($2,224,494)	$70,222,419
7	Total Revenue from Sales	$0	$440,193	($1,140,380)	$858,320,390
8	Other Operating Revenue	$0	$3,584,816	($157,642,987)	$82,982,759
9	Total Operating Revenue	$0	$4,025,009	($158,783,367)	$941,303,149
10					
11	Operating Expenses Before AFUDC				
12	Operation and Maintenance Expenses				
13	Steam Production	$0	$0	$0	($42,496,606)
14	Hydro Production	$0	$0	$0	($5,081,063)
15	Wind Production	$0	$0	$0	($15,824,779)
16	Solar Production	$0	($341,667)	$1,662,130	$0
17	Energy Storage	$0	$0	$0	($6,125)
18	Other Power Supply	$0	$0	$0	($2,231,385)
19	Purchased Power	$0	($47,152)	$229,383	($215,753,464)
20	Fuel	$0	$0	$0	($128,407,158)
21	Total Production	$0	($388,819)	$1,891,512	($409,800,579)
22	Transmission	$0	($8,148,535)	$27,414,646	($76,698,602)
23	Distribution	$0	$14,007	$62,138	($32,815,348)
24	Customer Accounting	$0	$0	$0	($7,447,719)
25	Customer Service and Information	$0	($801)	$448,426	($1,503,648)
26	Conservation Improvement Program	$0	$0	($2,180,002)	($17,145,250)
27	Administrative and General	$0	($14,919)	$11,069,519	($87,379,128)
28	Charitable Contributions	$0	$56	$474,395	($297,773)
29	Interest on Customer Deposits	$0	$0	$0	($2,391,000)
30	Total Operation and Maintenance Expenses	$0	($8,539,011)	$39,180,634	($635,479,046)
31	Depreciation Expense	$0	($863,199)	$4,535,640	($181,173,219)
32	Amortization Expense	$0	$759	$1,329,298	($9,268,369)
33	Taxes Other Than Income Taxes	$0	($276,975)	$944,465	($45,912,656)
34	Income Taxes	($10,194,500)	$1,672,628	$22,272,281	($209,512)
35	Deferred Income Taxes	$0	$27,013	($129,708)	$3,487,496
36	Investment Tax Credit	$0	$2	$2	$832,573
37	Total Operating Expenses Before AFUDC	($10,194,500)	($7,978,783)	$68,132,613	($867,722,733)
38					
39	Operating Income Before AFUDC	($10,194,500)	($3,953,774)	($90,650,754)	$73,580,416
40	Allowance for Funds Used During Construction	$0	$534,008	$534,008	$18,881,162
41	**Total Operating Income**	**($10,194,500)**	**($3,419,766)**	**($90,116,746)**	**$92,461,578**

Line No.	Description	Unadjusted Test Year 2027	Advertising Expense	Charitable Contributions	Economic Development	Organizational Dues	Employee Expenses	Asset Retirement Obligation
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Operating Revenue							
2	Sales by Rate Class	$915,974,170	$0	$0	$0	$0	$0	$0
3	Dual Fuel	$11,177,841	$0	$0	$0	$0	$0	$0
4	Intersystem Sales	$42,189,878	$0	$0	$0	$0	$0	$0
5	LP Demand Response	($3,655,110)	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$89,695,853	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$1,055,382,631	$0	$0	$0	$0	$0	$0
8	Other Operating Revenue	$308,219,867	$0	$0	$0	$0	$0	$0
9	Total Operating Revenue	$1,363,602,498	$0	$0	$0	$0	$0	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	($51,880,866)	$0	$0	$0	$0	$0	$0
14	Hydro Production	($6,230,280)	$0	$0	$0	$0	$0	$0
15	Wind Production	($19,077,721)	$0	$0	$0	$0	$0	$0
16	Solar Production	($2,003,797)	$0	$0	$0	$0	$0	$0
17	Energy Storage	($7,384)	$0	$0	$0	$0	$0	$0
18	Other Power Supply	($2,690,068)	$0	$0	$0	$0	$0	$0
19	Purchased Power	($267,248,859)	$0	$0	$0	$0	$0	$0
20	Fuel	($159,266,667)	$0	$0	$0	$0	$0	$0
21	Total Production	($508,405,642)	$0	$0	$0	$0	$0	$0
22	Transmission	($135,439,181)	$0	$0	$0	$0	$0	$0
23	Distribution	($35,629,445)	$5,000	$0	$0	$0	$0	$0
24	Customer Accounting	($7,478,334)	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	($1,956,386)	$2,842	$0	$83,250	$0	$0	$0
26	Conservation Improvement Program	($14,965,248)	$0	$0	$0	$0	$0	$0
27	Administrative and General	($115,881,961)	$478,235	$0	$426,858	$135,237	$747,838	$0
28	Charitable Contributions	($905,024)	$0	$555,992	$0	$0	$0	$0
29	Interest on Customer Deposits	($2,391,000)	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	($823,052,221)	$486,077	$555,992	$510,108	$135,237	$747,838	$0
31	Depreciation Expense	($221,827,035)	$0	$0	$0	$0	$0	$2,158,114
32	Amortization Expense	($12,431,698)	$0	$0	$0	$0	$0	$1,601,633
33	Taxes Other Than Income Taxes	($56,727,271)	$0	$0	$0	$0	$0	$0
34	Income Taxes	($31,605,772)	($139,708)	($159,803)	($146,615)	($38,870)	($214,944)	($1,080,627)
35	Deferred Income Taxes	$4,469,922	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$1,006,665	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($1,140,167,411)	$346,368	$396,189	$363,492	$96,367	$532,894	$2,679,121
38								
39	Operating Income Before AFUDC	$223,435,087	$346,368	$396,189	$363,492	$96,367	$532,894	$2,679,121
40	Allowance for Funds Used During Construction	$27,934,655	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$251,369,742**	**$346,368**	**$396,189**	**$363,492**	**$96,367**	**$532,894**	**$2,679,121**

Line No.	Description	Decommissioning	Boswell 3 Environmental Project	Conservation Expense	Years of Service Awards	Incentive Compensation	EV DCFC	EV Make Ready
		(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Operating Revenue							
2	Sales by Rate Class	$0	$0	$0	$0	$0	($91,451)	$0
3	Dual Fuel	$0	$0	$0	$0	$0	$0	$0
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$0	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$0	$0	$0	$0	$0	($91,451)	$0
8	Other Operating Revenue	$0	$0	$0	$0	$0	($164,446)	$0
9	Total Operating Revenue	$0	$0	$0	$0	$0	($255,897)	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$0	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$0	$0	$0	$0	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$0	$0	$0	$0	$0	$0
22	Transmission	$0	$0	$0	$0	$0	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$47,296	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$0	$0	$0
26	Conservation Improvement Program	$0	$0	($2,180,002)	$0	$0	$0	$0
27	Administrative and General	$0	$0	$0	$43,512	$5,383,326	$0	$0
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$0	($2,180,002)	$43,512	$5,383,326	$47,296	$0
31	Depreciation Expense	($2,156,154)	$589,351	$0	$0	$0	$324,815	$12,859
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
34	Income Taxes	$619,722	($169,391)	$626,576	($12,506)	($1,547,276)	($33,402)	($3,696)
35	Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($1,536,432)	$419,960	($1,553,426)	$31,006	$3,836,051	$338,709	$9,163
38								
39	Operating Income Before AFUDC	($1,536,432)	$419,960	($1,553,426)	$31,006	$3,836,051	$82,812	$9,163
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**($1,536,432)**	**$419,960**	**($1,553,426)**	**$31,006**	**$3,836,051**	**$82,812**	**$9,163**

Line No.	Description	Customer Upgrades	Aircraft Hangar	CARE	CIP Incentive	CIP Carrying Charge	CPA Incentive	CPA
		(15)	(16)	(17)	(18)	(19)	(20)	(21)
1	Operating Revenue							
2	Sales by Rate Class	$0	$0	($0)	$0	$0	$2,615,524	($5,435,611)
3	Dual Fuel	$0	$0	$0	$0	$0	$95,631	($204,881)
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$0	$0	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$0	$0	($0)	$0	$0	$2,711,154	($5,640,493)
8	Other Operating Revenue	$0	$0	$0	($2,969,622)	($41,519)	$0	$0
9	Total Operating Revenue	$0	$0	($0)	($2,969,622)	($41,519)	$2,711,154	($5,640,493)
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$0	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$0	$0	$0	$0	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$0	$0	$0	$0	$0	$0
22	Transmission	$0	$0	$0	$0	$0	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$0	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$0	$0	$0
26	Conservation Improvement Program	$0	$0	$0	$0	$0	$0	$0
27	Administrative and General	$0	$0	$0	$0	$0	$0	$0
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$0	$0	$0	$0	$0	$0
31	Depreciation Expense	$96,646	$69,620	$0	$0	$0	$0	$0
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
34	Income Taxes	($27,778)	($20,010)	$0	$853,529	$11,933	($779,240)	$1,621,190
35	Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	$68,868	$49,610	$0	$853,529	$11,933	($779,240)	$1,621,190
38								
39	Operating Income Before AFUDC	$68,868	$49,610	($0)	($2,116,093)	($29,586)	$1,931,914	($4,019,302)
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$68,868**	**$49,610**	**($0)**	**($2,116,093)**	**($29,586)**	**$1,931,914**	**($4,019,302)**

Line No.	Description	CCRC	Capacity Revenue and Expense	Reduce Employee Count	Revenue Budget Corrections	Continuing Cost Recovery Riders	Rate Case Expense	LTIP
		(22)	(23)	(24)	(25)	(26)	(27)	(28)
1	Operating Revenue							
2	Sales by Rate Class	$1,323,647	($129,436)	$0	$409,675	($1,112,650)	$0	$0
3	Dual Fuel	$0	($15,565)	$0	$0	($25,878)	$0	$0
4	Intersystem Sales	$0	$0	$0	$0	$0	$0	$0
5	LP Demand Response	$0	$3,655,110	$0	$0	$0	$0	$0
6	Sales for Resale	$0	($2,681,761)	$0	$0	$0	$0	$0
7	Total Revenue from Sales	$1,323,647	$828,348	$0	$409,675	($1,138,528)	$0	$0
8	Other Operating Revenue	$0	$0	$0	$0	($158,064,273)	$0	$0
9	Total Operating Revenue	$1,323,647	$828,348	$0	$409,675	($159,202,801)	$0	$0
10								
11	Operating Expenses Before AFUDC							
12	Operation and Maintenance Expenses							
13	Steam Production	$0	$0	$0	$0	$0	$0	$0
14	Hydro Production	$0	$0	$0	$0	$0	$0	$0
15	Wind Production	$0	$0	$0	$0	$0	$0	$0
16	Solar Production	$0	$0	$0	$0	$2,003,797	$0	$0
17	Energy Storage	$0	$0	$0	$0	$0	$0	$0
18	Other Power Supply	$0	$0	$0	$0	$0	$0	$0
19	Purchased Power	$0	$68,400	$0	$0	$208,134	$0	$0
20	Fuel	$0	$0	$0	$0	$0	$0	$0
21	Total Production	$0	$68,400	$0	$0	$2,211,931	$0	$0
22	Transmission	$0	$0	$0	$0	$35,563,181	$0	$0
23	Distribution	$0	$0	$0	$0	$0	$0	$0
24	Customer Accounting	$0	$0	$0	$0	$0	$0	$0
25	Customer Service and Information	$0	$0	$0	$0	$363,325	$0	$0
26	Conservation Improvement Program	$0	$0	$0	$0	$0	$0	$0
27	Administrative and General	$0	$0	$5,000,000	$0	$0	($1,756,956)	$2,836,925
28	Charitable Contributions	$0	$0	$0	$0	$0	$0	$0
29	Interest on Customer Deposits	$0	$0	$0	$0	$0	$0	$0
30	Total Operation and Maintenance Expenses	$0	$68,400	$5,000,000	$0	$38,138,437	($1,756,956)	$2,836,925
31	Depreciation Expense	$0	$0	$0	$0	$4,536,040	$0	$0
32	Amortization Expense	$0	$0	$0	$0	$0	$0	$0
33	Taxes Other Than Income Taxes	$0	$0	$0	$0	$1,221,440	$0	$0
34	Income Taxes	($380,443)	($257,743)	($1,437,100)	($117,749)	$33,141,504	$504,984	($815,389)
35	Deferred Income Taxes	$0	$0	$0	$0	($156,721)	$0	$0
36	Investment Tax Credit	$0	$0	$0	$0	$0	$0	$0
37	Total Operating Expenses Before AFUDC	($380,443)	($189,343)	$3,562,900	($117,749)	$76,880,701	($1,251,972)	$2,021,536
38								
39	Operating Income Before AFUDC	$943,204	$639,004	$3,562,900	$291,926	($82,322,100)	($1,251,972)	$2,021,536
40	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0
41	**Total Operating Income**	**$943,204**	**$639,004**	**$3,562,900**	**$291,926**	**($82,322,100)**	**($1,251,972)**	**$2,021,536**

Line No.	Description	Interest Synchronization	Changes in Allocations due to Adjustments	Total Adjustments	Interim Test Year 2027
		(29)	(30)	(31)	(32)
1	Operating Revenue				
2	Sales by Rate Class	$0	$0	($2,420,303)	$913,553,867
3	Dual Fuel	$0	$0	($150,693)	$11,027,147
4	Intersystem Sales	$0	$0	$0	$42,189,878
5	LP Demand Response	$0	$0	$3,655,110	$0
6	Sales for Resale	$0	$0	($2,681,761)	$87,014,092
7	Total Revenue from Sales	$0	$0	($1,597,648)	$1,053,784,983
8	Other Operating Revenue	$0	$0	($161,239,860)	$146,980,007
9	Total Operating Revenue	$0	$0	($162,837,508)	$1,200,764,990
10					
11	Operating Expenses Before AFUDC				
12	Operation and Maintenance Expenses				
13	Steam Production	$0	$0	$0	($51,880,866)
14	Hydro Production	$0	$0	$0	($6,230,280)
15	Wind Production	$0	$0	$0	($19,077,721)
16	Solar Production	$0	$0	$2,003,797	$0
17	Energy Storage	$0	$0	$0	($7,384)
18	Other Power Supply	$0	$0	$0	($2,690,068)
19	Purchased Power	$0	$0	$276,534	($266,972,325)
20	Fuel	$0	$0	$0	($159,266,667)
21	Total Production	$0	$0	$2,280,331	($506,125,311)
22	Transmission	$0	$0	$35,563,181	($99,876,000)
23	Distribution	$0	$0	$52,296	($35,577,149)
24	Customer Accounting	$0	$0	$0	($7,478,334)
25	Customer Service and Information	$0	$0	$449,417	($1,506,969)
26	Conservation Improvement Program	$0	$0	($2,180,002)	($17,145,250)
27	Administrative and General	$0	$0	$13,294,975	($102,586,986)
28	Charitable Contributions	$0	$0	$555,992	($349,032)
29	Interest on Customer Deposits	$0	$0	$0	($2,391,000)
30	Total Operation and Maintenance Expenses	$0	$0	$50,016,191	($773,036,031)
31	Depreciation Expense	$0	$0	$5,631,292	($216,195,744)
32	Amortization Expense	$0	$0	$1,601,633	($10,830,064)
33	Taxes Other Than Income Taxes	$0	$0	$1,221,440	($55,505,831)
34	Income Taxes	($12,765,698)	$0	$17,231,452	($14,374,320)
35	Deferred Income Taxes	$0	$0	($156,721)	$4,313,201
36	Investment Tax Credit	$0	$0	$0	$1,006,665
37	Total Operating Expenses Before AFUDC	($12,765,698)	$0	$75,545,286	($1,064,622,125)
38					
39	Operating Income Before AFUDC	($12,765,698)	$0	($87,292,222)	$136,142,866
40	Allowance for Funds Used During Construction	$0	$0	$0	$27,934,655
41	**Total Operating Income**	**($12,765,698)**	**$0**	**($87,292,222)**	**$164,077,520**

Minnesota Power
Docket No. E015/GR-26-199

Proposed Interim Rates Schedules
Interest Synchronization Adjustment
Direct Schedule B-9 (IR)
Volume 1

Line No.	Description	Calculation Note	Interim Test Year 2027	
			Total Company	Minnesota Jurisdiction
		(1)	(2)	(3)
1	Average Rate Base		$3,609,193,285	$2,626,893,825
2	Requested Weighted Cost of Debt		2.4439%	2.4439%
3	Interest	Line 1 * Line 2	$88,205,075	$64,198,658
4	Interest in Unadjusted Test Year		$132,619,857	$99,667,658
5	Interest Deduction Adjustment	Line 4 - Line 3	$44,414,783	$35,469,000
6				
7	Minnesota State Income Tax Rate		9.80%	9.80%
8	State Tax Interest Adjustment	Line 5 * Line 7 * - 1	($4,352,649)	($3,475,962)
9				
10	Effective Federal Income Tax Rate		18.94%	18.94%
11	Federal Tax Interest Adjustment	Line 5 * Line 10 * - 1	($8,413,048)	($6,718,538)
12				
13	**Total Interest Synchronization Adjustment**	Line 8 + Line 11	**($12,765,697)**	**($10,194,500)**

Line No.	Description	Calculation Note	Minnesota Jurisdiction	
			Unadjusted Test Year 2027	Interim Test Year 2027
		(1)	(2)	(3)
1	Average Rate Base		$4,078,221,623	$2,626,893,825
2	Operating Income Before AFUDC		$164,231,170	$73,580,412
3	AFUDC		$18,347,154	$18,881,162
4	Operating Income	Line 2 + Line 3	$182,578,324	$92,461,574
5	Rate of Return	Line 4 / Line 1	4.4769%	3.5198%
6	Required Rate of Return		7.5584%	7.5584%
7	Required Operating Income	Line 1 * Line 6	$308,248,303	$198,551,143
8	Operating Income Deficiency	Line 7 - Line 4	$125,669,979	$106,089,569
9	Gross Revenue Conversion Factor		1.40335	1.40335
10	Revenue Deficiency	Line 8 * Line 9	$176,359,116	$148,880,924
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$756,588,217	$754,017,218
12	Required Percent Increase	Line 10 / Line 11	23.31%	19.75%

Minnesota Power
Docket No. E015/GR-26-199

Interim and Final Rate Increases Net of Riders

Rate change compared to Dec 2027

	Interim	Final
Base rates	19.75%	22.09%
TCR offset: Duluth Loop to base rates 1/	-1.2%	-1.2%
RRR offset: PTCs to base rates 1/	-3.1%	-3.1%
Net bill impact	15.48%	17.83%

Revenue Deficiency ($ millions)

	Interim	Final	
Base rates	$148.9	$166.6	
TCR offset: Duluth Loop to base rates 1/	(9.2)	(9.2)	2/
RRR offset: PTCs to base rates 1/	(23.0)	(23.0)	3/
Net deficiency	116.7	134.4	

1/ The revenue requirements in the TCR rider for the Duluth Loop are moving to base rates 1/1/2027. The PTC true-up is being re-set to zero in the RRR rider as the PTCs are re-set in base rates 1/1/2027.
2/ Refer to B-11 (IR) page 2
3/ Refer to B-11 (IR) page 3

Minnesota Power
Docket No. E015/GR-26-199

Duluth Loop Revenue Requirements

Section	Line		Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
A	**Book Basis of Property**														
	0 CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	1 Plant in Service (excluding land)		83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	84,779,797	83,504,628	83,504,628	83,504,628	83,504,628
	2 Total Accumulated Depreciation		1,053,956	1,207,536	1,361,116	1,514,697	1,668,277	1,821,857	1,975,437	2,129,017	2,282,598	2,436,178	2,589,758	2,743,338	2,743,338
	3 Net Plant		82,450,672	82,297,092	82,143,512	81,989,931	81,836,351	81,682,771	81,529,191	81,375,611	82,497,199	81,068,450	80,914,870	80,761,290	80,761,290
	4 Total Depreciation		153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	1,842,962
	5 Book Depreciation Rate (45.3 year book life)		0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
B	**Tax Basis of Property**														
	1 Plant in Service		83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	83,504,628	84,779,797	83,504,628	83,504,628	83,504,628	83,504,628
	2 Accumulated Depreciation		8,012,357	8,641,870	9,271,384	9,900,898	10,530,412	11,159,925	11,789,439	12,418,953	13,048,466	13,677,980	14,307,494	14,937,008	14,937,008
	3 Net Plant		75,492,272	74,862,758	74,233,244	73,603,730	72,974,217	72,344,703	71,715,189	71,085,675	71,731,330	69,826,648	69,197,134	68,567,620	68,567,620
	4 Bonus Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Total Tax Depreciation		629,514	629,514	629,514	629,514	629,514	629,514	629,514	629,514	629,514	629,514	629,514	629,514	7,554,165
	6 Accumulated Tax Depreciation		8,012,357	8,641,870	9,271,384	9,900,898	10,530,412	11,159,925	11,789,439	12,418,953	13,048,466	13,677,980	14,307,494	14,937,008	14,937,008
	7 Tax Book Difference		6,958,400	7,434,334	7,910,268	8,386,201	8,862,135	9,338,068	9,814,002	10,289,935	10,765,869	11,241,802	11,717,736	12,193,670	12,193,670
	8 Income Tax Rate		28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%	28.74%
	9 Accumulated Deferred Income Tax Liability	1,863,061	1,999,844	2,136,628	2,273,411	2,410,194	2,546,978	2,683,761	2,820,544	2,957,327	3,094,111	3,230,894	3,367,677	3,504,461	3,504,461
	10 Deferred Tax Expense debit / (Credit)		136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783	136,783
C	**Revenue Requirements**														
	1 Net Plant		82,450,672	82,297,092	82,143,512	81,989,931	81,836,351	81,682,771	81,529,191	81,375,611	82,497,199	81,068,450	80,914,870	80,761,290	80,761,290
	2 Less: ADITL - Def Taxes		(1,999,844)	(2,136,628)	(2,273,411)	(2,410,194)	(2,546,978)	(2,683,761)	(2,820,544)	(2,957,327)	(3,094,111)	(3,230,894)	(3,367,677)	(3,504,461)	(3,504,461)
	3 Plus: ADITA - NOL		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: Land		-	-	-	-	-	-	-	-	1,275,169	1,275,169	1,275,169	1,275,169	1,275,169
	5 Rate Base		80,450,828	80,160,464	79,870,101	79,579,737	79,289,374	78,999,010	78,708,647	78,418,283	80,678,257	79,112,725	78,822,361	78,531,998	78,531,998
	6 Average Rate Base		80,596,009	80,305,646	80,015,282	79,724,919	79,434,555	79,144,192	78,853,829	78,563,465	79,548,270	79,895,491	78,967,543	78,677,180	78,677,180
	7 Current Return on CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Return on Average Rate Base														
	9 After Tax Return on Equity		343,507	342,269	341,032	339,794	338,557	337,319	336,082	334,844	339,041	340,521	336,566	335,329	4,064,861
	10 Income Tax Component		138,554	138,055	137,556	137,056	136,557	136,058	135,559	135,060	136,753	137,350	135,754	135,255	1,639,567
	11 Interest Expense Component		139,001	138,500	138,000	137,499	136,998	136,497	135,997	135,496	137,194	137,793	136,193	135,692	1,644,860
	12 Total Return on Average Rate Base		621,062	618,825	616,587	614,350	612,112	609,875	607,637	605,400	612,988	615,664	608,513	606,276	7,349,288
	13 Operation & Maintenance Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Depreciation Expense		153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	153,580	1,842,962
	15 Property Tax		224,939	224,939	224,939	224,939	224,939	224,939	224,939	224,939	224,939	224,939	224,939	224,939	2,699,263
	16 Prorata ADIT		(17,475)												(17,475)
	17 Monthly Revenue Requirements		982,106	997,343	995,106	992,868	990,631	988,393	986,156	983,918	991,507	994,183	987,032	984,795	11,874,038
	18 MN Jurisdictional Allocator 1/		0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114	0.77114
	19 MN Jurisdictional Revenue Requirement		757,341	769,091	767,366	765,640	763,915	762,190	760,464	758,739	764,591	766,654	761,140	759,415	**9,156,546**

1/ Proposed 2027 Test Year Transmission MN Jurisdictional Allocator

Minnesota Power
Docket No. E015/GR-26-199

Line		Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total Year 2027
	PTC Reset (MN Jurisdiction) 1/													
1	PTC True-Up	2,347,415	2,264,327	2,308,612	2,277,756	2,141,499	1,587,372	1,408,962	1,639,645	2,203,811	2,589,423	2,241,809	(42,197)	22,968,433
2	Impact of Discount	7,597	7,418	7,864	7,523	6,834	5,103	3,802	4,284	5,463	6,976	7,932	6,875	77,671
3	Rate Base Impact of Sale of PTCs	-	-	(1,194)	(2,388)	(2,388)	(2,388)	(3,473)	(4,559)	(4,559)	(4,559)	(4,559)	(4,559)	(34,624)
4	Total	2,355,012	2,271,745	2,315,282	2,282,892	2,145,946	1,590,088	1,409,290	1,639,370	2,204,715	2,591,839	2,245,182	(39,881)	23,011,480

Notes:
1/ Proposed 2027 Test Year MN Jurisdictional Allocator Used

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Interim Test Year 2027	Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,323,854,513	$1,272,894,129	($50,960,384)
3	Hydro	$200,626,862	$207,952,377	$7,325,515
4	Wind	$703,711,001	$659,828,189	($43,882,812)
5	Solar	$0	$0	$0
6	Transmission	$1,002,129,799	$1,112,960,023	$110,830,224
7	Distribution	$730,048,444	$930,744,366	$200,695,921
8	General Plant	$235,080,907	$311,388,660	$76,307,753
9	Intangible Plant	$69,348,840	$90,334,735	$20,985,895
10	Total Plant In Service	$4,264,800,366	$4,586,102,478	$321,302,112
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($727,820,864)	($817,476,147)	($89,655,284)
14	Hydro	($48,524,141)	($52,361,140)	($3,836,998)
15	Wind	($209,781,851)	($244,525,180)	($34,743,329)
16	Solar	$0	$0	$0
17	Transmission	($289,344,192)	($322,898,886)	($33,554,694)
18	Distribution	($344,700,746)	($387,973,202)	($43,272,456)
19	General Plant	($103,448,051)	($125,316,895)	($21,868,844)
20	Intangible Plant	($49,196,099)	($74,752,994)	($25,556,895)
21	Total Accumulated Depreciation and Amortization	($1,772,815,945)	($2,025,304,445)	($252,488,500)
22				
23	Net Plant Before CWIP			
24	Steam	$596,033,649	$455,417,982	($140,615,667)
25	Hydro	$152,102,720	$155,591,237	$3,488,517
26	Wind	$493,929,150	$415,303,009	($78,626,141)
27	Solar	$0	$0	$0
28	Transmission	$712,785,607	$790,061,136	$77,275,530
29	Distribution	$385,347,698	$542,771,163	$157,423,465
30	General Plant	$131,632,855	$186,071,765	$54,438,909
31	Intangible Plant	$20,152,741	$15,581,740	($4,571,001)
32	Total Net Plant Before CWIP	$2,491,984,421	$2,560,798,033	$68,813,612
33	Construction Work in Progress	$87,604,048	$242,987,155	$155,383,107
34	Utility Plant	$2,579,588,469	$2,803,785,188	$224,196,720
35				
36	Working Capital			
37	Fuel Inventory	$19,346,103	$19,556,262	$210,158
38	Materials and Supplies	$33,639,458	$56,530,899	$22,891,441
39	Prepayments	$25,509,562	$21,614,969	($3,894,594)
40	Cash Working Capital	($42,819,861)	($38,711,136)	$4,108,724
41	Total Working Capital	$35,675,263	$58,990,993	$23,315,730
42				
43	Additions and Deductions			
44	Asset Retirement Obligation	$0	$0	$0
45	Electric Vehicle Program	$0	$0	$0
46	Workers Compensation Deposit	$69,510	$71,322	$1,812
47	Unamortized UMWI Transaction Cost	$824,269	$701,960	($122,309)
48	Customer Advances	($2,208,000)	($3,666,416)	($1,458,416)
49	Other Deferred Credits - Hibbard	($300,727)	($281,381)	$19,346
50	Wind Performance Deposit	($132,978)	($124,424)	$8,554
51	Accumulated Deferred Income Taxes	($247,180,162)	($232,583,417)	$14,596,745
52	Total Additions and Deductions	($248,928,088)	($235,882,356)	$13,045,732
53				
54	**Total Average Rate Base**	**$2,366,335,644**	**$2,626,893,825**	**$260,558,182**

1/ Docket No. E015/PA-24-198

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the last Order in Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198. This summary explains changes shown in Direct Schedule C-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to a difference in allocation factors applied to the Interim Test Year.
Hydro Production Plant	The increase is primarily due to on-going capital investment and upgrades to hydro generation units such as gate, crane, and concrete replacement and refurbishment projects with the majority of work at Blanchard to refurbish head gates and Unit 1, offset by the difference in allocation factors applied to the Interim Test Year.
Wind Production Plant	The decrease is primarily due to a difference in allocation factors applied to the Interim Test Year.
Transmission Plant	The increase is primarily due to the inclusion of the Duluth Loop Reliability Project as well as on-going capital investments and upgrades to improve reliability and power quality.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality.
General Plant	The increase is primarily due to on-going capital investments with the majority due to AHQ 4th floor remodel and the Little Falls Service Center project.
Intangible Plant	The increase is primarily due to on-going capital investments, primarily software, to improve safety, security, and reliability.
Accumulated Depreciation and Amortization	Accumulated depreciation and amortization reserves increased primarily due to the additions of plant and increases in salvage rates due to updated decommissioning studies for Boswell Energy Center.
Construction Work In Progress	The increase is primarily due to changes in the level of capital investment from year to year.

Item	Description and Basis
Working Capital	Material and supplies increased primarily due to cost increases reflecting inflation and supply chain constraints experienced over the last several years. These inflationary pressures and supply chain constraints have resulted in increased prices for materials as well as lead times for procurement. Prepayments decreased primarily due to amortization of the contract prepayment with Silver Bay Power. This was partially offset by higher prepaid insurance and higher prepaid software balances.
Accumulated Deferred Income Taxes	The increase is primarily due to book depreciation in excess of tax depreciation partially offset by usage of production tax credits.

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Interim Test Year 2027	Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$741,289,550	$742,990,070	$1,700,520
3	Dual Fuel	$10,440,637	$11,027,148	$586,512
4	Intersystem Sales	$37,829,282	$34,080,750	($3,748,532)
5	LP Demand Response	($864,000)	$0	$864,000
6	Sales for Resale	$118,880,356	$70,222,419	($48,657,937)
7	Total Revenue from Sales	$907,575,825	$858,320,388	($49,255,437)
8	Other Operating Revenue	$64,141,078	$82,982,759	$18,841,681
9	Total Operating Revenue	$971,716,903	$941,303,147	($30,413,756)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($47,166,222)	($42,496,606)	$4,669,616
14	Hydro Production	($5,015,418)	($5,081,063)	($65,645)
15	Wind Production	($18,171,175)	($15,824,779)	$2,346,396
16	Solar Production	$0	$0	$0
17	Energy Storage	$0	($6,125)	($6,125)
18	Other Power Supply	($1,507,917)	($2,231,385)	($723,467)
19	Purchased Power	($310,090,053)	($215,753,464)	$94,336,589
20	Fuel	($118,376,133)	($128,407,158)	($10,031,025)
21	Total Production	($500,326,918)	($409,800,579)	$90,526,339
22	Transmission	($53,200,878)	($76,698,602)	($23,497,724)
23	Distribution	($27,754,513)	($32,815,348)	($5,060,835)
24	Customer Accounting	($6,877,280)	($7,447,719)	($570,439)
25	Customer Service and Information	($1,793,529)	($1,503,648)	$289,882
26	Conservation Improvement Program	($12,531,684)	($17,145,250)	($4,613,566)
27	Sales	($24,373)	$0	$24,373
28	Administrative and General	($64,728,354)	($87,379,128)	($22,650,773)
29	Charitable Contributions	($229,430)	($297,773)	($68,342)
30	Interest on Customer Deposits	($2,520,000)	($2,391,000)	$129,000
31	Total Operation and Maintenance Expenses	($669,986,959)	($635,479,046)	$34,507,913
32	Depreciation Expense	($140,058,387)	($181,173,220)	($41,114,834)
33	Amortization Expense	($18,422,564)	($9,268,369)	$9,154,195
34	Taxes Other Than Income Taxes	($49,772,163)	($45,912,656)	$3,859,508
35	Income Taxes	($18,756,236)	($209,514)	$18,546,722
36	Deferred Income Taxes	$29,319,643	$3,487,496	($25,832,147)
37	Investment Tax Credit	$807,568	$832,573	$25,005
38	Total Operating Expenses Before AFUDC	($866,869,098)	($867,722,735)	($853,638)
39				
40	Operating Income Before AFUDC	$104,847,805	$73,580,412	($31,267,394)
41	Allowance for Funds Used During Construction	$3,239,954	$18,881,162	$15,641,208
42	**Total Operating Income**	**$108,087,759**	**$92,461,574**	**($15,626,185)**

1/ Docket No. E015/PA-24-198

Description of Changes in Operating Income
Interim 2027 Test Year compared to Approved 2024 Test Year

In this Volume 1, Direct Schedule C-4(IR), Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the last Order Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198. This summary explains changes shown on Volume 1, Direct Schedule C-3 (IR).

Item	Description and Basis
Operating Revenue:	The comparison of revenue by rate class is based on the approved 2024 test year revenue in Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198 (2024 test year) as compared to the interim 2027 test year revenue in the present docket (2027 test year).
Sales by Rate Class	Sales by Rate Class revenue increased from the 2024 test year to the 2027 test year primarily due to recovery of higher fuel adjustment clause costs in the 2027 test year. This increase is partially offset by a decrease in customer load in the 2027 test year as the Company has experienced a considerable decrease in customer demand from two large power customers.
Dual Fuel	No significant change.
Intersystem Sales	Intersystem Sales revenue decreased from the 2024 test year to the 2027 test year primarily due to decreased sales to Silver Bay Power Corporation.
LP Demand Response	LP Demand Response credits decreased from the 2024 test year to the 2027 test year due to demand response being removed from base rates as these credits are now recovered through the Capacity Revenue and Expense Adjustment Rider.
Sales for Resale	Sales for Resale revenue decreased from the 2024 test year to the 2027 test year primarily due to the expiration of a power sales agreement with Minnkota Power Cooperative, Inc. (Minnkota Power) on December 31, 2026. In the 2024 test year, Minnesota Power sold approximately 41 percent of its 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte) to Minnkota Power. See "Purchased Power." This decrease is partially offset by higher pricing on market sales and more Company generation available for sale in the market.
Other Operating Revenue	Other Operating Revenue increased from the 2024 test year to the 2027 test year due to more transmission revenue following the 2026 implementation of Attachment N-1 for the recovery of expenses for the HVDC Modernization project. See corresponding expense offset in "Operating Expenses – Transmission."
Operating Expenses:	
Steam Production	Steam Production expense decreased from the 2024 test year to the 2027 test year primarily due to the 2024 test year including costs for nitrogen oxide allowances. Nitrogen Oxide allowances were subsequently moved to the Rider for Fuel and Purchased Energy. A lower Jurisdictional Factor for O&M – Steam in the 2027 test year compared to the 2024 test year also contributed to the decrease. These increases were partially offset by higher expenses for labor and benefits, contracted professional services and materials.
Hydro Production	No significant change.

Item	Description and Basis
Wind Production	Wind Production expense decreased from the 2024 test year to the 2027 test year primarily due to approximately 50 percent of the Bison Wind Energy Center turbines ending their coverage under the long-term service agreement for the Bison Wind Energy Center during 2026. Minnesota Power now self-performs maintenance on these additional turbines.
Energy Storage	No significant change.
Other Power Supply	No significant change.
Purchased Power	Purchased Power expense decreased from 2024 test year to the 2027 test year primarily due to the expiration of a power purchase agreement with Square Butte on December 31, 2026. In the 2024 test year, Minnesota Power sold approximately 41 percent of its 50 percent output entitlement from Square Butte to Minnkota Power, under a power sales agreement which expires December 31, 2026. See “Sales for Resale.”
Fuel	Fuel expense increased from the 2024 test year to the 2027 test year primarily due to more generation and higher fuel costs in the 2027 test year.
Transmission	Transmission expenses increased from the 2024 test year to the 2027 test year primarily due to the inclusion of Attachment N-1 expense related to the HVDC Modernization project. See corresponding revenue offset in “Other Operating Revenue.” This increase was partially offset by the impact of a lower Jurisdictional Factor for O&M – Transmission in the 2027 test year compared to the 2024 test year.
Distribution	Distribution expenses increased from the 2024 test year to the 2027 test year primarily due to higher expenses for labor and benefits.
Customer Accounting	No significant change.
Customer Service and Information	No significant change.
Conservation Improvement Program	Customer Improvement Program expense increased from the 2024 test year to the 2027 test year primarily due to higher expected expenditures under Minnesota Power’s 2027-2029 Energy Conservation and Optimization Triennial plan.
Sales	No significant change.
Administrative and General	Administrative and General expenses increased from the 2024 test year to the 2027 test year primarily due to higher expenses for labor and benefits reflecting annual wage increases, headcount growth, and increased cost of benefits, higher insurance expenses, and higher costs for contracted professional services. These increases were partially offset by the impact of a lower Jurisdictional Factor for O&M – Administrative and General in the 2027 test year compared to the 2024 test year. Further, the Interim 2027 test year includes a $5.0 million Total Company ($4.3 million MN Jurisdictional) adjustment that reduces O&M expenses for Interim Rates to reflect the potential timing lag associated with filling planned positions and to proactively pass potential savings on to customers. This adjustment does not reflect a change in the Company's workforce requirements but rather recognizes the uncertainty regarding the timing of achieving budgeted staffing levels.
Charitable Contributions	No significant change.

Item	Description and Basis
Interest on Customer Deposits	No significant change.
Depreciation Expense	Depreciation Expense increased from the 2024 test year to the 2027 test year primarily due to higher plant in-service balances for distribution, steam production and general plant. An increase in salvage rates due to updated decommissioning studies for Boswell Energy Center also contributed to higher depreciation expense in the 2027 test year.
Amortization Expense	Amortization expense decreased from the 2024 test year to the 2027 test year due to the absence of Taconite Harbor Energy Center in the 2027 Test Year as recovery ends in 2026.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes decreased from the 2024 test year to the 2027 test year primarily due to a decrease in property tax expense from a decrease in tax rates.
Income Taxes / Deferred Income Taxes	Income Taxes reflect higher pretax income and lower production tax credits in the 2027 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from the 2024 test year to the 2027 test year primarily due to increased change in the level of capital investment from year to year.

Line No.	Description	Calculation Note	Minnesota Jurisdiction		
			Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Interim Test Year 2027	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,366,335,644	$2,626,893,825	$260,558,182
2	Operating Income Before AFUDC		$104,847,805	$73,580,412	($31,267,394)
3	AFUDC		$3,239,954	$18,881,162	$15,641,208
4	Operating Income	Line 2 + Line 3	$108,087,759	$92,461,574	($15,626,185)
5	Rate of Return	Line 4 / Line 1	4.5677%	3.5198%	(1.0479%)
6	Required Rate of Return		7.1841%	7.5584%	0.3743%
7	Required Operating Income	Line 1 * Line 6	$169,999,919	$198,551,143	$28,551,224
8	Operating Income Deficiency	Line 7 - Line 4	$61,912,160	$106,089,569	$44,177,409
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$86,884,504	$148,880,924	$61,996,420
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$751,730,187	$754,017,218	$2,287,031
12	Required Percent Increase	Line 10 / Line 11	11.56%	19.75%	

1/ Docket No. E015/PA-24-198

Minnesota Power
Comparison of Most Recently Approved
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction
(Thousands of Dollars)

I. Capital structure and rate of return calculation approved by the commission in Minnesota Power's most recent general rate case (Docket No. E-015/GR-23-155)

	Amount	% of Total	Component Cost	Weighted Cost
Long Term Debt	$1,428,143 [1]	47.0000%	4.4035%	2.0696%
Short Term Debt	$0	0.0000%	0.0000%	0.0000%
Total Debt	$1,428,143	47.0000%		2.0696%
Common Equity	$1,610,460 [1]	53.0000%	9.6500% [2]	5.1145%
Total Capitalization	$3,038,603	100.0000%		7.1841%

II. Capital structure and rate of return calculation for proposed interim rates 2027

	Projected Amount	Projected % of Total	Requested[3] Interim % of Total	Component Cost	Weighted Cost
Long Term Debt	$2,465,436	45.7084%	46.0248%	5.2177%	2.4014%
Short Term Debt	$52,603	0.9752%	0.9752%	4.3551%	0.0425%
Total Debt	$2,518,039	46.6836%	47.0000%		2.4439%
Common Equity	$2,875,797	53.3164%	53.0000%	9.6500%	5.1145%
Total Capitalization	$5,393,836	100.0000%	100.0000%		7.5584%

III. Amount of changes between I and II

	Most Recent General Rate Case Filing	Projected Interim Year	Change
Long Term Debt	$1,428,143	$2,465,436	$1,037,293
Short Term Debt	$0	$52,603	$52,603
Total Debt	$1,428,143	$2,518,039	$1,089,896
Common Equity	$1,610,460	$2,875,797	$1,265,337
Total Capitalization	$3,038,603	$5,393,836	$2,355,233

[1] The Long-Term Debt and Common Equity amounts above from Minnesota Power's most recent general rate case are derived from the requested total capitalization combined with the approved equity ratio from Docket No. E015/GR-23-155.

[2] A Common Equity component cost of 9.78 percent was originally approved in Docket No. E015/GR-23-155 but was subsequently reduced to 9.65 percent as part of the Acquisition Settlement in Docket No. E015/PA-24-198.

[3] The interim test year cost of capital is based on the requested capital structure. The Company carries a capital structure in line with its allowed capital structure, but slight fluctuations occur due to specific timing of debt and equity issuances and expenditures. Although the Company is projected to carry an equity ratio of 53.3164%, the Company is requesting an equity ratio of 53.0000%.

Minnesota Power
Comparison of Most Recently Approved
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction

I. The long term debt portion of the capital structure proposed in this rate case increased by approximately $1,037.3 million compared to the last rate case filing in Docket No. E015/GR-23-155. The component cost of long term debt increased from 4.4035% in the 2023 rate filing to 5.2177% in the current rate filing.

$52.6 million of Short Term Debt was added to the capital structure in the interim test year. There was no Short Term Debt in the last rate case filing in Docket No. E015/GR-23-155.

Common equity increased by $1,265.3 million due to actual and projected issuances of common stock and increases in retained earnings.

Note: The Long Term Debt, Short Term Debt, and Common Equity amounts from Minnesota Power's most recent general rate case that were used to calculate the change in capital structure are derived from the requested total capitalized combined with the approved equity ratio from Docket No. E015/GR-23-155, which remained unchanged in Docket No. E015/PA-24-198.

				Operating Revenues		Increase	
	Customer Classes	**Customers**	**MWh**	**Present**	**Interim**	**$**	**%**
1	Residential	117,578	615,678	$ 145,652,322	$ 174,411,414	$ 28,759,092	19.75%
2	General Service	22,321	1,413,556	$ 97,659,789	$ 116,942,742	$ 19,282,953	19.75%
3	Large Light & Power	444	839,805	$ 136,251,876	$ 163,154,847	$ 26,902,971	19.75%
4	Large Power	8	3,913,879	$ 359,096,163	$ 429,999,802	$ 70,903,639	19.75%
5	Lighting	5,259	9,935	$ 4,421,373	$ 5,294,374	$ 873,001	19.75%
6	Subtotal by Customer Class	145,609	6,792,853	$ 743,081,523	$ 889,803,180	$ 146,721,657	19.75%
	Dual Fuel (Interruptible)						
7	Dual Fuel - Residential	7,089	76,973	$ 9,262,599	$ 11,091,502	$ 1,089,719	19.75%
8	Dual Fuel - Commercial/Industrial	484	15,194	$ 1,764,548	$ 2,112,959	$ 263,620	19.75%
9	Subtotal Dual Fuel	7,573	92,167	$ 11,027,147	$ 13,204,461	$ 2,177,313	19.75%
10	**Total Sales of Electricity**	**153,182**	**6,885,020**	**$ 754,108,671**	**$ 903,007,641**	**$ 148,898,970**	**19.75%**
11	Contract Revenue			$ 38,230,173	$ 38,230,173	$ -	0.00%
12	**Total Sales of Electricity (incl. Contract Revenue)**			**$ 792,338,844**	**$ 941,237,814**	**$ 148,898,970**	**18.79%**
	Adjustments for Riders						
	Retail SEA			$ 1,007,562	$ 1,007,562	$ -	0.00%
	Capacity Rider			$ (145,001)	$ (145,001)		
	Conservation Program Adjustment			$ 5,640,593	$ 5,640,593	$ -	0.00%
	CCRC			$ 1,323,647	$ 1,323,647	$ -	0.00%
	Transmission Adjustment			$ 67,314,201	$ 67,314,201	$ -	0.00%
	Renewable Adjustment			$ 73,816,672	$ 73,816,672	$ -	0.00%
	SRRR			$ 1,335,807	$ 1,335,807	$ -	0.00%
	Community Solar Garden - Customer Charge			$ 122,664	$ 122,664	$ -	0.00%
	Community Solar Garden - Energy Charge			$ 8,302	$ 8,302	$ -	0.00%
	CARE Surcharge			$ 4,418,183	$ 4,418,183	$ -	0.00%
	CARE Discount			$ (4,418,183)	$ (4,418,183)	$ -	0.00%
	Subtotal Revenue Adjustments			**$ 150,424,447**	**$ 150,424,447**	**$ -**	**0.00%**
	Total E-Schedule Revenue			**$ 942,763,290**	**$ 1,091,662,260**	**$ 148,898,970**	**15.79%**

Line No.	Description	Minnesota Jurisdiction		
		Most Recent Fiscal Year 2025	Interim Test Year 2027	Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,419,516,133	$1,272,894,129	($146,622,004)
3	Hydro	$202,503,135	$207,952,377	$5,449,242
4	Wind	$706,686,170	$659,828,189	($46,857,980)
5	Solar	$178,526	$0	($178,526)
6	Transmission	$1,057,902,397	$1,112,960,023	$55,057,626
7	Distribution	$780,468,421	$930,744,366	$150,275,944
8	General Plant	$244,518,714	$311,388,660	$66,869,946
9	Intangible Plant	$76,684,078	$90,334,735	$13,650,657
10	Total Plant In Service	$4,488,457,573	$4,586,102,478	$97,644,905
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($685,818,837)	($817,476,147)	($131,657,310)
14	Hydro	($59,142,805)	($52,361,140)	$6,781,665
15	Wind	($226,218,411)	($244,525,180)	($18,306,769)
16	Solar	($53,263)	$0	$53,263
17	Transmission	($267,484,884)	($322,898,886)	($55,414,003)
18	Distribution	($297,986,221)	($387,973,202)	($89,986,981)
19	General Plant	($105,567,038)	($125,316,895)	($19,749,857)
20	Intangible Plant	($58,670,799)	($74,752,994)	($16,082,196)
21	Total Accumulated Depreciation and Amortization	($1,700,942,259)	($2,025,304,445)	($324,362,186)
22				
23	Net Plant Before CWIP			
24	Steam	$733,697,296	$455,417,982	($278,279,314)
25	Hydro	$143,360,330	$155,591,237	$12,230,908
26	Wind	$480,467,759	$415,303,009	($65,164,750)
27	Solar	$125,262	$0	($125,262)
28	Transmission	$790,417,513	$790,061,136	($356,377)
29	Distribution	$482,482,200	$542,771,163	$60,288,964
30	General Plant	$138,951,675	$186,071,765	$47,120,089
31	Intangible Plant	$18,013,279	$15,581,740	($2,431,539)
32	Total Net Plant Before CWIP	$2,787,515,315	$2,560,798,033	($226,717,281)
33	Construction Work in Progress	$301,960,320	$242,987,155	($58,973,165)
34	Utility Plant	$3,089,475,635	$2,803,785,188	($285,690,446)
35				
36	Working Capital			
37	Fuel Inventory	$18,104,769	$19,556,262	$1,451,493
38	Materials and Supplies	$48,905,068	$56,530,899	$7,625,831
39	Prepayments	$151,507,874	$21,614,969	($129,892,906)
40	Cash Working Capital	($31,710,723)	($38,711,136)	($7,000,413)
41	Total Working Capital	$186,806,988	$58,990,993	($127,815,995)
42				
43	Additions and Deductions			
44	Asset Retirement Obligation	($168,514,427)	$0	$168,514,427
45	Electric Vehicle Program	$416,171	$0	($416,171)
46	Workers Compensation Deposit	$59,651	$71,322	$11,671
47	Unamortized UMWI Transaction Cost	$730,723	$701,960	($28,763)
48	Customer Advances	($3,353,588)	($3,666,416)	($312,828)
49	Other Deferred Credits - Hibbard	($297,918)	($281,381)	$16,537
50	Wind Performance Deposit	($131,736)	($124,424)	$7,312
51	Accumulated Deferred Income Taxes	($301,089,611)	($232,583,417)	$68,506,194
52	Total Additions and Deductions	($472,180,735)	($235,882,356)	$236,298,379
53				
54	**Total Average Rate Base**	**$2,804,101,887**	**$2,626,893,825**	**($177,208,062)**

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the Most Recent Fiscal Year 2025. This summary explains changes shown in Direct Schedule D-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to a difference in allocation factors applied to the Interim Test Year and adjustments in the 2027 test year for plant in-service, partially offset by regularly-scheduled, necessary, critical turbine refurbishments for the boiler air heater, cooling tower stack, and boiler superheat pendant on Boswell Unit 3, cyclical turbine overhaul on Boswell Unit 4, and on-going capital investment.
Hydro Production Plant	The increase is primarily due to the repowering of several hydro turbines and generators for Blanchard, Scanlon, and Thomson as well as other on-going capital investment and upgrades to hydro generation units such as gate, crane, and concrete replacement and refurbishment projects.
Wind Production Plant	The decrease is due to adjustments in the 2027 test year for plant in-service, partially offset by on-going capital investment and upgrades to wind generation units such as generator, blade and gearbox replacements.
Transmission Plant	The increase is due to the inclusion of the Duluth Loop Reliability Project as well as on-going capital investments and upgrades to improve reliability and power quality, partially offset by adjustments in the 2027 test year for plant in-service.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality, partially offset by adjustments in the 2027 test year for plant in-service.
General Plant	The increase is primarily due to on-going capital investments with the majority due to AHQ 4th floor remodel and the Little Falls Service Center project, partially offset by adjustments in the 2027 test year for plant in-service.
Intangible Plant	The increase is primarily due to on-going capital investments, primarily software, to improve safety, security, and reliability.

Item	Description and Basis
Accumulated Depreciation and Amortization	Depreciation and Amortization reserves, for all except hydro and solar plant increased primarily due to the additions of tangible and intangible plant. There are also adjustments in the 2027 test year for accumulated depreciation and amortization that contributed to these increases and decreases.
Construction Work In Progress (CWIP)	The increase is primarily due to changes in the level of capital investment from year to year, partially offset by the adjustment for the removal of the cost recovery rider projects in the 2027 test year.
Working Capital	Fuel inventory increased primarily due to the continuation of bringing fuel inventory back to a normal target inventory level. Materials and supplies increased primarily due to cost increases reflecting inflation and supply chain constraints experienced over the last several years. These inflationary pressures and supply chain constraints have resulted in increased prices for materials as well as lead times for procurement. Prepayments decreases are primarily due to adjustments in the 2027 interim test year to remove the prepaid pension asset and the prepaid OPEB asset. The amortization of the contract prepayment with Silver Bay Power also contributed to the decrease.
Asset Retirement Obligation	There is an adjustment in the 2027 test year to remove asset retirement obligations.
Accumulated Deferred Income Taxes	The increase is primarily due to book depreciation in excess of tax depreciation, and the inclusion of the accumulated deferred income taxes for the prepaid pension asset and prepaid OPEB asset in rate base in the Most Recent Fiscal Year 2025.

Line No.	Description	Minnesota Jurisdiction		
		Most Recent Fiscal Year 2025	Interim Test Year 2027	Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$748,623,547	$742,990,070	($5,633,477)
3	Dual Fuel	$9,679,548	$11,027,148	$1,347,600
4	Intersystem Sales	$32,968,596	$34,080,750	$1,112,154
5	LP Demand Response	($1,842,800)	$0	$1,842,800
6	Sales for Resale	$169,731,268	$70,222,419	($99,508,849)
7	Total Revenue from Sales	$959,160,159	$858,320,388	($100,839,771)
8	Other Operating Revenue	$126,013,524	$82,982,759	($43,030,765)
9	Total Operating Revenue	$1,085,173,683	$941,303,147	($143,870,536)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($40,191,463)	($42,496,606)	($2,305,143)
14	Hydro Production	($4,156,791)	($5,081,063)	($924,272)
15	Wind Production	($17,798,568)	($15,824,779)	$1,973,790
16	Solar Production	($102,189)	$0	$102,189
17	Energy Storage	$0	($6,125)	($6,125)
18	Other Power Supply	($1,734,252)	($2,231,385)	($497,133)
19	Purchased Power	($305,037,909)	($215,753,464)	$89,284,445
20	Fuel	($119,370,899)	($128,407,158)	($9,036,259)
21	Total Production	($488,392,071)	($409,800,579)	$78,591,492
22	Transmission	($84,383,890)	($76,698,602)	$7,685,288
23	Distribution	($25,403,715)	($32,815,348)	($7,411,632)
24	Customer Accounting	($6,301,800)	($7,447,719)	($1,145,919)
25	Customer Service and Information	($2,174,543)	($1,503,648)	$670,895
26	Conservation Improvement Program	($13,061,187)	($17,145,250)	($4,084,063)
27	Sales	$754	$0	($754)
28	Administrative and General	($75,423,216)	($87,379,128)	($11,955,911)
29	Charitable Contributions	($785,154)	($297,773)	$487,381
30	Interest on Customer Deposits	($2,662,069)	($2,391,000)	$271,069
31	Total Operation and Maintenance Expenses	($698,586,892)	($635,479,046)	$63,107,846
32	Depreciation Expense	($147,352,910)	($181,173,220)	($33,820,310)
33	Amortization Expense	($21,714,917)	($9,268,369)	$12,446,549
34	Taxes Other Than Income Taxes	($42,239,893)	($45,912,656)	($3,672,763)
35	Income Taxes	($19,029,061)	($209,514)	$18,819,547
36	Deferred Income Taxes	$695,469	$3,487,496	$2,792,027
37	Investment Tax Credit	$887,217	$832,573	($54,644)
38	Total Operating Expenses Before AFUDC	($927,340,987)	($867,722,735)	$59,618,252
39				
40	Operating Income Before AFUDC	$157,832,696	$73,580,412	($84,252,284)
41	Allowance for Funds Used During Construction	$6,289,642	$18,881,162	$12,591,520
42	**Total Operating Income**	**$164,122,338**	**$92,461,574**	**($71,660,764)**

Description of Changes in Operating Income
Interim 2027 Test Year compared to 2025

In this Volume 1, Direct Schedule D-4(IR), Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the most recent fiscal year 2025. This summary explains changes shown on Volume 1, Direct Schedule D-3 (IR).

Item	Description and Basis
Operating Revenue:	The comparison of revenue by rate class is based on 2025 revenue as compared to the interim 2027 test year revenue in the present docket (2027 test year).
Sales by Rate Class	Sales by Rate Class revenue decreased from 2025 to the 2027 test year primarily due to lower customer load, as the Company has experienced a considerable decrease in customer demand from two large power customers. This decrease is partially offset by recovery of higher fuel adjustment clause costs in the 2027 test year.
Dual Fuel	Dual Fuel revenue increased from 2025 to the 2027 test year primarily due to an increase in customer load and recovery of higher fuel adjustment clause costs in the 2027 test year.
Intersystem Sales	Intersystem revenue increased from 2025 to the 2027 test year primarily due to more sales to Silver Bay Power Corporation at higher average prices, partially offset by lower intersystem sales to large power customers.
LP Demand Response	LP Demand Response credits decreased from 2025 to the 2027 test year due to demand response being removed from base rates as these credits are now recovered through the Capacity Revenue and Expense Adjustment Rider.
Sales for Resale	Sales for Resale revenue decreased from 2025 to the 2027 test year primarily due to the expiration of a power sales agreement with Minnkota Power Cooperative, Inc. (Minnkota Power) on December 31, 2026. In 2025 Minnesota Power sold approximately 46 percent of its 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte) to Minnkota Power. See "Purchased Power."
Other Operating Revenue	Other Operating Revenue decreased from 2025 to the 2027 test due to the exclusion of revenue related to the continuing riders for Transmission Cost Recovery and Renewable Resources from the 2027 test year. This decrease was partially offset by the inclusion of Attachment N-1 revenue in the 2027 test year for the recovery of expenses related to the HVDC Modernization project. See corresponding expense offset in "Operating Expenses – Transmission."
Operating Expenses:	
Steam Production	Steam Production expense increased from 2025 to the 2027 test year primarily due to higher expenses for labor, benefits, and materials. These increases were partially offset by a lower Jurisdictional Factor for O&M – Steam in the 2027 test year compared to the 2025 also contributed to the decrease.
Hydro Production	No significant change.
Wind Production	Wind Production expense decreased from 2025 to the 2027 test year primarily due to approximately 50 percent of the Bison Wind Energy Center turbines ending their coverage under the long-term service agreement for the Bison Wind Energy Center during 2026. Minnesota Power now self-performs maintenance on these additional turbines.

Item	Description and Basis
Solar Production	No significant change.
Energy Storage	No significant change.
Other Power Supply	No significant change.
Purchased Power	Purchased Power expense decreased from 2025 to the 2027 test year primarily due to the expiration of a power purchase agreement with Square Butte on December 31, 2026. In 2025, Minnesota Power sold approximately 46 percent of its 50 percent output entitlement from Square Butte to Minnkota Power. See “Sales for Resale.” A decrease in customer load also contributed to lower purchased power expense in the 2027 test year.
Fuel	Fuel expense increased from 2025 to the 2027 test year primarily due to higher fuel costs in the 2027 test year, partially offset by lower generation due to decreased customer load.
Transmission	Transmission expense decreased from 2025 to the 2027 test year primarily due to an adjustment in the 2027 test year to remove expenses that will remain in a continuing cost recovery rider. A lower Jurisdictional Factor for O&M – Transmission in the 2027 test year compared to the 2025 also contributed to the decrease. These decreases were partially offset by the inclusion of Attachment N-1 expense related to the HVDC Modernization project. See corresponding revenue offset in “Other Operating Revenue.” Higher expenses for labor and benefits as well as vegetation management also partially offset the decrease.
Distribution	Distribution expenses decreased from 2025 to the 2027 test year primarily due to higher expenses for labor and benefits, increased vegetation management activity, and lower budgeted pre-capital transformer expenditures, resulting in fewer offsetting transformer credits.
Customer Accounting	Customer Accounting expenses increased from the 2025 to the 2027 test year primarily due to higher expenses for labor and benefits and higher contracted professional services.
Customer Service and Information	No significant change.
Conservation Improvement Program	Conservation Improvement Program expenses increased from 2025 to the 2027 test year primarily due to higher expected spending on conservation programs. The 2024 test year expense is based on Minnesota Power’s 2027-2029 Energy Conservation and Optimization Triennial plan.
Sales	No significant change.
Administrative and General	Administrative and General expenses increased from 2025 to the 2027 test year primarily due to higher expenses for labor and benefits reflecting annual wage increases, headcount growth, and increased cost of benefits, increased costs for software and hardware maintenance and services, higher insurance expenses, and higher costs for contracted professional services. These increases were partially offset by interim rate adjustments to reduce staffing levels and incentive compensation in the interim test year as well as the impact of a lower Jurisdictional Factor for O&M – Administrative and General in the 2027 test year compared to 2025. Further, the Interim 2027 test year includes a $5.0 million Total Company ($4.3 million MN Jurisdictional) adjustment that reduces O&M expenses for Interim

Item	Description and Basis
	Rates to reflect the potential timing lag associated with filling planned positions and to proactively pass potential savings on to customers. This adjustment does not reflect a change in the Company's workforce requirements but rather recognizes the uncertainty regarding the timing of achieving budgeted staffing levels.
Charitable Contributions	Charitable Contributions decreased from 2025 to the 2027 test year primarily due to an adjustment to reduce 2027 test year charitable contributions to 50 percent of the average of the three most recently completed years.
Interest on Customer Deposits	Interest on Customer Deposits decreased from 2025 to the 2027 test year due to lower Large Power Sales, partially offset by higher interest rates. This interest primarily relates to weekly billings to Large Power customers which are reduced by an interest component that is included as a Company expense. Interest calculation is based on billings to customers which will vary from year to year.
Depreciation Expense	Depreciation Expense increased from 2025 to the 2027 test year primarily due to higher plant in-service balances for steam production and general plant. An increase in salvage rates due to updated decommissioning studies for Boswell Energy Center also contributed to higher depreciation expense in the 2027 test year.
Amortization Expense	Amortization expense increased from 2025 to the 2027 test year primarily due to the absence of Taconite Harbor Energy Center in the 2027 Test Year as recovery ends in 2026.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes increased from 2025 to the 2027 test year primarily due to prior year true-ups recorded in 2025.
Income Taxes / Deferred Income Taxes	Income Taxes reflect lower pretax income in the 2027 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from 2025 to the 2027 test year primarily due to increased change in the level of capital investment from year to year.

Line No.	Line	Calculation Note	Minnesota Jurisdiction		
			Most Recent Fiscal Year 2025	Interim Test Year 2027	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,804,101,887	$2,626,893,825	($177,208,062)
2	Operating Income Before AFUDC		$157,832,696	$73,580,412	($84,252,284)
3	AFUDC		$6,289,642	$18,881,162	$12,591,520
4	Operating Income	Line 2 + Line 3	$164,122,338	$92,461,574	($71,660,764)
5	Rate of Return	Line 4 / Line 1	5.8529%	3.5198%	(2.3331%)
6	Required Rate of Return		7.1966%	7.5584%	0.3618%
7	Required Operating Income	Line 1 * Line 6	$201,799,996	$198,551,143	($3,248,854)
8	Operating Income Deficiency	Line 7 - Line 4	$37,677,658	$106,089,569	$68,411,911
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$52,874,987	$148,880,924	$96,005,937
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$758,303,095	$754,017,218	($4,285,877)
12	Required Percent Increase	Line 10 / Line 11	6.97%	19.75%	

Minnesota Power
Comparison of Most Recent Fiscal Year
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction
(Thousands of Dollars)

I. Capital structure and rate of return calculation for most recent fiscal year 2025

	Amount	% of Total	Component Cost	Weighted Cost
Long Term Debt	$1,529,648	48.1843%	4.5583%	2.1964%
Short Term Debt	$0	0.0000%	0.0000%	0.0000%
Total Debt	$1,529,648	48.1843%		2.1964%
Common Equity	$1,644,927	51.8157%	7.0568%	3.6565%
Total Capitalization	$3,174,575	100.0000%		5.8529%

II. Capital structure and rate of return calculation for proposed interim rates 2027

	Projected Amount	Projected % of Total	Requested[1] Interim % of Total	Component Cost	Weighted Cost
Long Term Debt	$2,465,436	45.7084%	46.0248%	5.2177%	2.4014%
Short Term Debt	$52,603	0.9752%	0.9752%	4.3551%	0.0425%
Total Debt	$2,518,039	46.6836%	47.0000%		2.4439%
Common Equity	$2,875,797	53.3164%	53.0000%	9.6500%	5.1145%
Total Capitalization	$5,393,836	100.0000%	100.0000%		7.5584%

III. Amount of changes between I and II

	Most Recent Fiscal Year	Projected Interim Year	Change
Long Term Debt	$1,529,648	$2,465,436	$935,788
Short Term Debt	$0	$52,603	$52,603
Total Debt	$1,529,648	$2,518,039	$988,391
Common Equity	$1,644,927	$2,875,797	$1,230,870
Total Capitalization	$3,174,575	$5,393,836	$3,207,652

[1] The interim test year cost of capital is based on the requested capital structure. The Company carries a capital structure in line with its allowed capital structure, but slight fluctuations occur due to specific timing of debt and equity issuances and expenditures. Although the Company is projected to carry an equity ratio of 53.3164%, the Company is requesting an equity ratio of 53.0000%.

Minnesota Power
Comparison of Most Recent Fiscal Year
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction

I. The Long Term Debt portion of the capital structure proposed in this rate case increased by approximately $935.8 million compared to the most recent fiscal year (2025). The component cost of Long-Term Debt increased from 4.5583% in the 2025 fiscal year to 5.2177% in the current rate filing.

$52.6 million of Short Term Debt was added to the capital structure in the interim test year. There was no Short Term Debt in the most recent fiscal year (2025).

Common Equity increased by $1,230.9 million due to actual and projected issuances of common stock and increases in retained earnings.

Note: The interim Long Term Debt, Short Term Debt, and Common Equity amounts are derived from the projected total capitalization combined with the requested equity ratio of 53.0000% from Docket No. E-015/GR-26-199.

Line No.	Description	Minnesota Jurisdiction: Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Minnesota Jurisdiction: Proposed Test Year 2027	Minnesota Jurisdiction: Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,323,854,513	$1,272,894,129	($50,960,384)
3	Hydro	$200,626,862	$207,952,377	$7,325,515
4	Wind	$703,711,001	$659,828,189	($43,882,812)
5	Solar	$0	$0	$0
6	Transmission	$1,002,129,799	$1,112,960,023	$110,830,224
7	Distribution	$730,048,444	$934,117,358	$204,068,914
8	General Plant	$235,080,907	$311,413,532	$76,332,626
9	Intangible Plant	$69,348,840	$90,341,951	$20,993,110
10	Total Plant In Service	$4,264,800,366	$4,589,507,559	$324,707,193
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($727,820,864)	($817,476,147)	($89,655,284)
14	Hydro	($48,524,141)	($52,361,140)	($3,836,998)
15	Wind	($209,781,851)	($244,525,180)	($34,743,329)
16	Solar	$0	$0	$0
17	Transmission	($289,344,192)	($322,898,886)	($33,554,694)
18	Distribution	($344,700,746)	($388,379,091)	($43,678,345)
19	General Plant	($103,448,051)	($125,326,905)	($21,878,854)
20	Intangible Plant	($49,196,099)	($74,758,965)	($25,562,866)
21	Total Accumulated Depreciation and Amortization	($1,772,815,945)	($2,025,726,314)	($252,910,370)
22				
23	Net Plant Before CWIP			
24	Steam	$596,033,649	$455,417,982	($140,615,667)
25	Hydro	$152,102,720	$155,591,237	$3,488,517
26	Wind	$493,929,150	$415,303,009	($78,626,141)
27	Solar	$0	$0	$0
28	Transmission	$712,785,607	$790,061,136	$77,275,530
29	Distribution	$385,347,698	$545,738,267	$160,390,569
30	General Plant	$131,632,855	$186,086,627	$54,453,772
31	Intangible Plant	$20,152,741	$15,582,985	($4,569,756)
32	Total Net Plant Before CWIP	$2,491,984,421	$2,563,781,245	$71,796,823
33	Construction Work in Progress	$87,604,048	$242,990,586	$155,386,539
34	Utility Plant	$2,579,588,469	$2,806,771,831	$227,183,362
35				
36	Working Capital			
37	Fuel Inventory	$19,346,103	$19,556,262	$210,158
38	Materials and Supplies	$33,639,458	$56,530,902	$22,891,444
39	Prepayments	$25,509,562	$134,060,034	$108,550,471
40	Cash Working Capital	($42,819,861)	($38,928,346)	$3,891,514
41	Total Working Capital	$35,675,263	$171,218,851	$135,543,588
42				
43	Additions and Deductions			
44	Asset Retirement Obligation	$0	$0	$0
45	Electric Vehicle Program	$0	$0	$0
46	Workers Compensation Deposit	$69,510	$71,327	$1,817
47	Unamortized UMWI Transaction Cost	$824,269	$701,960	($122,309)
48	Customer Advances	($2,208,000)	($3,666,416)	($1,458,416)
49	Other Deferred Credits - Hibbard	($300,727)	($281,381)	$19,346
50	Wind Performance Deposit	($132,978)	($124,424)	$8,554
51	Accumulated Deferred Income Taxes	($247,180,162)	($266,004,288)	($18,824,126)
52	Total Additions and Deductions	($248,928,088)	($269,303,221)	($20,375,133)
53				
54	**Total Average Rate Base**	**$2,366,335,644**	**$2,708,687,461**	**$342,351,817**

1/ Docket No. E015/PA-24-198

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the last Order in Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198. This summary explains changes shown in Direct Schedule E-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to a difference in allocation factors applied to the Proposed Test Year.
Hydro Production Plant	The increase is primarily due to on-going capital investment and upgrades to hydro generation units such as gate, crane, and concrete replacement and refurbishment projects with the majority of work at Blanchard to refurbish head gates and Unit 1, offset by the difference in allocation factors applied to the Proposed Test Year.
Wind Production Plant	The decrease is primarily due to the difference in allocation factors applied to the Proposed Test Year.
Transmission Plant	The increase is primarily due to the inclusion of the Duluth Loop Reliability Project as well as on-going capital investments and upgrades to improve reliability and power quality.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality.
General Plant	The increase is primarily due to on-going capital investments with the majority due to AHQ 4th floor remodel and the Little Falls Service Center project.
Intangible Plant	The increase is primarily due to on-going capital investments, primarily software, to improve safety, security, and reliability.
Accumulated Depreciation and Amortization	Accumulated depreciation and amortization reserves increased primarily due to the additions of plant and increases in salvage rates due to updated decommissioning studies for Boswell Energy Center.
Construction Work In Progress	The increase is primarily due to changes in the level of capital investment from year to year.

Item	Description and Basis
Working Capital	Material and supplies increased primarily due to cost increases reflecting inflation and supply chain constraints experienced over the last several years. These inflationary pressures and supply chain constraints have resulted in increased prices for materials as well as lead times for procurement. Prepayment increases are primarily due to inclusion of the prepaid pension asset in rate base in the proposed test year. The prepaid pension asset was denied in the most recent rate case. This was partially offset by amortization of the contract prepayment with Silver Bay Power.
Taconite Harbor Energy Center	The decrease is due to the regulated asset balance for Taconite Harbor being included in the most recent rate case but not proposed interim rates. Continued cost recovery ends in 2026 for Taconite Harbor. In 2024 the regulated asset for Taconite Harbor was a debit balance so the adjustment increased rate base.
Accumulated Deferred Income Taxes	The decrease is primarily due to usage of production tax credits partially offset by book depreciation in excess of tax depreciation.

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Proposed Test Year 2027	Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$741,289,550	$743,081,521	$1,791,971
3	Dual Fuel	$10,440,637	$11,027,148	$586,512
4	Intersystem Sales	$37,829,282	$34,080,750	($3,748,532)
5	LP Demand Response	($864,000)	$0	$864,000
6	Sales for Resale	$118,880,356	$70,222,419	($48,657,937)
7	Total Revenue from Sales	$907,575,825	$858,411,839	($49,163,986)
8	Other Operating Revenue	$64,141,078	$83,197,839	$19,056,762
9	Total Operating Revenue	$971,716,903	$941,609,678	($30,107,225)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($47,166,222)	($42,496,606)	$4,669,616
14	Hydro Production	($5,015,418)	($5,081,063)	($65,645)
15	Wind Production	($18,171,175)	($15,824,779)	$2,346,396
16	Solar Production	$0	$0	$0
17	Energy Storage	$0	($6,125)	($6,125)
18	Other Power Supply	($1,507,917)	($2,231,385)	($723,467)
19	Purchased Power	($310,090,053)	($215,753,464)	$94,336,589
20	Fuel	($118,376,133)	($128,407,158)	($10,031,025)
21	Total Production	($500,326,918)	($409,800,579)	$90,526,339
22	Transmission	($53,200,878)	($76,698,602)	($23,497,724)
23	Distribution	($27,754,513)	($33,237,329)	($5,482,817)
24	Customer Accounting	($6,877,280)	($7,447,719)	($570,439)
25	Customer Service and Information	($1,793,529)	($1,503,648)	$289,882
26	Conservation Improvement Program	($12,531,684)	($17,145,250)	($4,613,566)
27	Sales	($24,373)	$0	$24,373
28	Administrative and General	($64,728,354)	($94,110,023)	($29,381,669)
29	Charitable Contributions	($229,430)	($297,796)	($68,366)
30	Interest on Customer Deposits	($2,520,000)	($2,391,000)	$129,000
31	Total Operation and Maintenance Expenses	($669,986,959)	($642,631,947)	$27,355,013
32	Depreciation Expense	($140,058,387)	($181,563,256)	($41,504,869)
33	Amortization Expense	($18,422,564)	($9,269,131)	$9,153,433
34	Taxes Other Than Income Taxes	($49,772,163)	($45,915,570)	$3,856,593
35	Income Taxes	($18,756,236)	$2,442,245	$21,198,481
36	Deferred Income Taxes	$29,319,643	$3,487,433	($25,832,211)
37	Investment Tax Credit	$807,568	$832,573	$25,005
38	Total Operating Expenses Before AFUDC	($866,869,098)	($872,617,653)	($5,748,555)
39				
40	Operating Income Before AFUDC	$104,847,805	$68,992,025	($35,855,780)
41	Allowance for Funds Used During Construction	$3,239,954	$18,881,429	$15,641,475
42	**Total Operating Income**	**$108,087,759**	**$87,873,454**	**($20,214,305)**

1/ Docket No. E015/PA-24-198

Description of Changes in Operating Income
Proposed 2027 Test Year compared to Approved 2024 Test Year

In this Volume 1, Direct Schedule E-4(IR), Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the last Order Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198. This summary explains changes shown on Volume 1, Direct Schedule E-3 (IR).

Item	Description and Basis
Operating Revenue:	The comparison of revenue by rate class is based on the approved 2024 test year revenue in Docket No. E015/GR-23-155, as modified by the December 10, 2025 Order in Docket No. E015/PA-24-198 (2024 test year) as compared to the proposed 2027 test year revenue in the present docket (2027 test year).
Sales by Rate Class	Sales by Rate Class revenue increased from the 2024 test year to the 2027 test year due to recovery of higher fuel adjustment clause costs in the 2027 test year. This increase is partially offset by a decrease in customer load in the 2027 test year, as the Company has experienced a considerable decrease in customer demand from two large power customers.
Dual Fuel	No significant change.
Intersystem Sales	Intersystem Sales revenue decreased from the 2024 test year to the 2027 test year primarily due to decreased sales to Silver Bay Power Corporation.
LP Demand Response	LP Demand Response credits decreased from the 2024 test year to the 2027 test year due to demand response being removed from base rates as these credits are now recovered through the Capacity Revenue and Expense Adjustment Rider.
Sales for Resale	Sales for Resale revenue decreased from the 2024 test year to the 2027 test year primarily due to the expiration of a power sales agreement with Minnkota Power Cooperative, Inc. (Minnkota Power) on December 31, 2026. In the 2024 test year, Minnesota Power sold approximately 41 percent of its 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte) to Minnkota Power. See "Purchased Power". This decrease is partially offset by higher pricing on market sales and more Company generation available for sale in the market.
Other Operating Revenue	Other Operating Revenue increased from the 2024 test year to the 2027 test year due to more transmission revenue following the 2026 implementation of Attachment N-1 for the recovery of expenses for the HVDC Modernization project. See corresponding expense offset in "Operating Expenses – Transmission".
Operating Expenses:	
Steam Production	Steam Production expense decreased from the 2024 test year to the 2027 test year primarily due to the 2024 test year including costs for nitrogen oxide allowances. Nitrogen Oxide allowances were subsequently moved to the Rider for Fuel and Purchased Energy. A lower Jurisdictional Factor for O&M – Steam in the 2027 test year compared to the 2024 test year also contributed to the decrease. These increases were partially offset by higher expenses for labor and benefits, contracted professional services and materials.

Item	Description and Basis
Hydro Production	No significant change.
Wind Production	Wind Production expense decreased from the 2024 test year to the 2027 test year primarily due to approximately 50 percent of the Bison Wind Energy Center turbines ending their coverage under the long-term service agreement for the Bison Wind Energy Center during 2026. Minnesota Power now self-performs maintenance on these additional turbines.
Energy Storage	No significant change.
Other Power Supply	No significant change.
Purchased Power	Purchased Power expense decreased from 2024 test year to the 2027 test year primarily due to the expiration of a power purchase agreement with Square Butte on December 31, 2026. In the 2024 test year, Minnesota Power sold approximately 41 percent of its 50 percent output entitlement from Square Butte to Minnkota Power, under a power sales agreement which expires December 31, 2026. See “Sales for Resale”.
Fuel	Fuel expense increased from the 2024 test year to the 2027 test year primarily due to more generation and higher fuel costs in the 2027 test year.
Transmission	Transmission expenses increased from the 2024 test year to the 2027 test year primarily due to the inclusion of Attachment N-1 expense related to the HVDC Modernization project. See corresponding revenue offset in “Other Operating Revenue”. This increase was partially offset by the impact of a lower Jurisdictional Factor for O&M – Transmission in the 2027 test year compared to the 2024 test year.
Distribution	Distribution expenses increased from the 2024 test year to the 2027 test year primarily due to higher expenses for labor and benefits
Customer Accounting	No Significant Change.
Customer Service and Information	No significant change.
Conservation Improvement Program	Customer Improvement Program expense increased from the 2024 test year to the 2027 test year primarily due to higher expected expenditures under Minnesota Power’s 2027-2029 Energy Conservation and Optimization Triennial plan.
Sales	No significant change.
Administrative and General	Administrative and General expenses increased from the 2024 test year to the 2027 test year primarily due to higher expenses for labor and benefits reflecting annual wage increases, headcount growth, and increased cost of benefits, higher insurance expenses, and higher costs for contracted professional services. The 2024 test year also reflected additional adjustments reducing executive compensation and employee compensation that are not reflected in the 2027 test year. These increases were partially offset by the impact of a lower Jurisdictional Factor for O&M – Administrative and General in the 2027 test year compared to the 2024 test year.
Charitable Contributions	No significant change.

Item	Description and Basis
Interest on Customer Deposits	No significant change.
Depreciation Expense	Depreciation Expense increased from the 2024 test year to the 2027 test year primarily due to higher plant in-service balances for distribution, steam production and general plant. An increase in salvage rates due to updated decommissioning studies for Boswell Energy Center also contributed to higher depreciation expense in the 2027 test year.
Amortization Expense	Amortization expense increased from the 2024 test year to the 2027 test year primarily due to the absence of Taconite Harbor Energy Center in the 2027 Test Year as recovery ends in 2026.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes decreased from the 2024 test year to the 2027 test year primarily due to a decrease in property tax expense from a decrease in tax rates.
Income Taxes / Deferred Income Taxes	Income Taxes reflect higher pretax income and lower production tax credits in the 2027 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from the 2024 test year to the 2027 test year primarily due to increased change in the level of capital investment from year to year.

Line No.	Description	Calculation Note	Minnesota Jurisdiction		
			Results of Most Recent Rate Case E015/GR-23-155 with ROE Reduction 1/	Proposed Test Year 2027	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,366,335,644	$2,708,687,461	$342,351,817
2	Operating Income Before AFUDC		$104,847,805	$68,992,025	($35,855,780)
3	AFUDC		$3,239,954	$18,881,429	$15,641,475
4	Operating Income	Line 2 + Line 3	$108,087,759	$87,873,454	($20,214,305)
5	Rate of Return	Line 4 / Line 1	4.5677%	3.2441%	(1.3236%)
6	Required Rate of Return		7.1841%	7.6273%	0.4432%
7	Required Operating Income	Line 1 * Line 6	$169,999,919	$206,599,719	$36,599,800
8	Operating Income Deficiency	Line 7 - Line 4	$61,912,160	$118,726,264	$56,814,105
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$86,884,504	$166,614,646	$79,730,142
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$751,730,187	$754,108,669	$2,378,482
12	Required Percent Increase	Line 10 / Line 11	11.56%	22.09%	

1/ Docket No. E015/PA-24-198

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Proposed Test Year 2027	Interim Test Year 2027	Difference	Proposed Test Year 2027	Interim Test Year 2027	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
1	Plant In Service						
2	Steam	$1,533,849,686	$1,533,849,686	$0	$1,272,894,129	$1,272,894,129	$0
3	Hydro	$251,719,345	$251,719,345	$0	$207,952,377	$207,952,377	$0
4	Wind	$800,262,112	$800,262,112	$0	$659,828,189	$659,828,189	$0
5	Transmission	$1,442,337,302	$1,442,337,302	$0	$1,112,960,023	$1,112,960,023	$0
6	Distribution	$1,007,758,383	$1,004,385,394	($3,372,989)	$934,117,358	$930,744,366	($3,372,992)
7	General Plant	$364,991,550	$364,991,573	$23	$311,413,532	$311,388,660	($24,873)
8	Intangible Plant	$105,885,086	$105,885,092	$7	$90,341,951	$90,334,735	($7,216)
9	Total Plant In Service	$5,506,803,464	$5,503,430,504	($3,372,959)	$4,589,507,559	$4,586,102,478	($3,405,081)
10							
11	Accumulated Depreciation and Amortization						
12	Steam	($985,309,568)	($985,309,568)	$0	($817,476,147)	($817,476,147)	$0
13	Hydro	($63,379,278)	($63,379,278)	$0	($52,361,140)	($52,361,140)	$0
14	Wind	($296,647,030)	($296,647,030)	$0	($244,525,180)	($244,525,180)	$0
15	Transmission	($418,012,679)	($418,012,679)	$0	($322,898,886)	($322,898,886)	$0
16	Distribution	($418,997,426)	($418,670,383)	$327,043	($388,379,091)	($387,973,202)	$405,889
17	General Plant	($146,889,125)	($146,889,134)	($9)	($125,326,905)	($125,316,895)	$10,010
18	Intangible Plant	($87,621,082)	($87,621,088)	($6)	($74,758,965)	($74,752,994)	$5,971
19	Total Accumulated Depreciation and Amortization	($2,416,856,187)	($2,416,529,160)	$327,028	($2,025,726,314)	($2,025,304,445)	$421,870
20							
21	Net Plant Before CWIP						
22	Steam	$548,540,118	$548,540,118	$0	$455,417,982	$455,417,982	$0
23	Hydro	$188,340,068	$188,340,068	$0	$155,591,237	$155,591,237	$0
24	Wind	$503,615,082	$503,615,082	$0	$415,303,009	$415,303,009	$0
25	Transmission	$1,024,324,623	$1,024,324,623	$0	$790,061,136	$790,061,136	$0
26	Distribution	$588,760,958	$585,715,011	($3,045,946)	$545,738,267	$542,771,163	($2,967,104)
27	General Plant	$218,102,425	$218,102,439	$14	$186,086,627	$186,071,765	($14,863)
28	Intangible Plant	$18,264,004	$18,264,005	$1	$15,582,985	$15,581,740	($1,245)
29	Total Net Plant Before CWIP	$3,089,947,276	$3,086,901,345	($3,045,931)	$2,563,781,245	$2,560,798,033	($2,983,211)
30	Construction Work in Progress	$735,499,121	$735,499,124	$3	$242,990,586	$242,987,155	($3,431)
31	Utility Plant	$3,825,446,397	$3,822,400,469	($3,045,928)	$2,806,771,831	$2,803,785,188	($2,986,643)
32							
33	Working Capital						
34	Fuel Inventory	$24,256,129	$24,256,129	$0	$19,556,262	$19,556,262	$0
35	Materials and Supplies	$69,111,154	$69,111,154	$0	$56,530,902	$56,530,899	($3)
36	Prepayments	$158,014,105	$26,225,313	($131,788,792)	$134,060,034	$21,614,969	($112,445,065)
37	Cash Working Capital	($46,816,914)	($46,661,356)	$155,558	($38,928,346)	($38,711,136)	$217,210
38	Total Working Capital	$204,564,474	$72,931,240	($131,633,234)	$171,218,851	$58,990,993	($112,227,858)
39							
40	Additions and Deductions						
41	Asset Retirement Obligation	$0	$0	$0	$0	$0	$0
42	Electric Vehicle Program	$0	$0	$0	$0	$0	$0
43	Workers Compensation Deposit	$83,599	$83,599	$0	$71,327	$71,322	($6)
44	Unamortized UMWI Transaction Cost	$909,703	$909,703	$0	$701,960	$701,960	$0
45	Customer Advances	($3,666,416)	($3,666,416)	($0)	($3,666,416)	($3,666,416)	($0)
46	Other Deferred Credits - Hibbard	($339,222)	($339,222)	$0	($281,381)	($281,381)	$0
47	Wind Performance Deposit	($150,000)	($150,000)	$0	($124,424)	($124,424)	$0
48	Accumulated Deferred Income Taxes	($322,191,846)	($282,976,088)	$39,215,758	($266,004,288)	($232,583,417)	$33,420,871
49	Total Additions and Deductions	($325,354,182)	($286,138,424)	$39,215,758	($269,303,221)	($235,882,356)	$33,420,865
50							
51	**Total Average Rate Base**	**$3,704,656,689**	**$3,609,193,285**	**($95,463,404)**	**$2,708,687,461**	**$2,626,893,825**	**($81,793,635)**

General Description

The Company has identified these significant events affecting changes in the major categories of Rate Base between the Interim Test Year and Proposed Test Year**.** This summary explains changes shown in Direct Schedule F-1 (IR).

Item	Description and Basis
Distribution Plant	The difference is primarily due the removal of plant related to the Electric Vehicle Direct Current Fast Charger (EV DCFC) program from the Interim Test Year.
Prepayments	Prepayment differences are primarily due to inclusion of the prepaid pension asset in rate base for the Proposed Test Year, but not for the Proposed Interim Test Year.
Accumulated Deferred Income Taxes	The difference in Accumulated Deferred Income Taxes is associated with the change for prepayments for the Prepaid Pension Asset and EV DCFC program costs as described above.

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Proposed Test Year 2027	Interim Test Year 2027	Difference	Proposed Test Year 2027	Interim Test Year 2027	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$913,645,315	$913,553,864	($91,451)	$743,081,521	$742,990,070	($91,451)
3	Dual Fuel	$11,027,148	$11,027,148	$0	$11,027,148	$11,027,148	$0
4	Intersystem Sales	$42,189,878	$42,189,878	$0	$34,080,750	$34,080,750	$0
5	LP Demand Response	$0	$0	$0	$0	$0	$0
6	Sales for Resale	$87,014,092	$87,014,092	$0	$70,222,419	$70,222,419	$0
7	Total Revenue from Sales	$1,053,876,432	$1,053,784,981	($91,451)	$858,411,839	$858,320,388	($91,451)
8	Other Operating Revenue	$147,211,517	$146,980,007	($231,510)	$83,197,839	$82,982,759	($215,080)
9	Total Operating Revenue	$1,201,087,949	$1,200,764,988	($322,961)	$941,609,678	$941,303,147	($306,531)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($51,880,866)	($51,880,866)	$0	($42,496,606)	($42,496,606)	$0
14	Hydro Production	($6,230,280)	($6,230,280)	$0	($5,081,063)	($5,081,063)	$0
15	Wind Production	($19,077,721)	($19,077,721)	$0	($15,824,779)	($15,824,779)	$0
16	Energy Storage	($7,384)	($7,384)	$0	($6,125)	($6,125)	$0
17	Other Power Supply	($2,690,068)	($2,690,068)	$0	($2,231,385)	($2,231,385)	$0
18	Purchased Power	($266,972,325)	($266,972,325)	$0	($215,753,464)	($215,753,464)	$0
19	Fuel	($159,266,667)	($159,266,667)	$0	($128,407,158)	($128,407,158)	$0
20	Total Production	($506,125,311)	($506,125,311)	$0	($409,800,579)	($409,800,579)	$0
21	Transmission	($99,876,001)	($99,876,001)	$0	($76,698,602)	($76,698,602)	$0
22	Distribution	($36,024,579)	($35,577,149)	$447,430	($33,237,329)	($32,815,348)	$421,982
23	Customer Accounting	($7,478,334)	($7,478,334)	$0	($7,447,719)	($7,447,719)	$0
24	Customer Service and Information	($1,506,969)	($1,506,969)	$0	($1,503,648)	($1,503,648)	$0
25	Conservation Improvement Program	($17,145,250)	($17,145,250)	$0	($17,145,250)	($17,145,250)	$0
26	Administrative and General	($110,467,417)	($102,586,986)	$7,880,431	($94,110,023)	($87,379,128)	$6,730,895
27	Charitable Contributions	($349,032)	($349,032)	($0)	($297,796)	($297,773)	$24
28	Interest on Customer Deposits	($2,391,000)	($2,391,000)	($0)	($2,391,000)	($2,391,000)	($0)
29	Total Operation and Maintenance Expenses	($781,363,892)	($773,036,031)	$8,327,861	($642,631,947)	($635,479,046)	$7,152,901
30	Depreciation Expense	($216,606,218)	($216,195,744)	$410,474	($181,563,256)	($181,173,220)	$390,036
31	Amortization Expense	($10,830,064)	($10,830,064)	($1)	($9,269,131)	($9,268,369)	$762
32	Taxes Other Than Income Taxes	($55,505,831)	($55,505,831)	($0)	($45,915,570)	($45,912,656)	$2,915
33	Income Taxes	($11,285,012)	($14,374,321)	($3,089,309)	$2,442,245	($209,514)	($2,651,759)
34	Deferred Income Taxes	$4,313,201	$4,313,201	($0)	$3,487,433	$3,487,496	$63
35	Investment Tax Credit	$1,006,665	$1,006,665	$0	$832,573	$832,573	$0
36	Total Operating Expenses Before AFUDC	($1,070,271,151)	($1,064,622,126)	$5,649,025	($872,617,653)	($867,722,735)	$4,894,917
37							
38	Operating Income Before AFUDC	$130,816,798	$136,142,862	$5,326,064	$68,992,025	$73,580,412	$4,588,386
39	Allowance for Funds Used During Construction	$27,934,655	$27,934,655	$0	$18,881,429	$18,881,162	($267)
40	**Total Operating Income**	**$158,751,453**	**$164,077,517**	**$5,326,065**	**$87,873,454**	**$92,461,574**	**$4,588,120**

General Description

The Company has identified these significant events affecting changes in the major categories of Operating Income between the Interim Test Year and Proposed Test Year**.** This summary explains changes shown in Direct Schedule F-3 (IR).

Item	Description and Basis
O&M – A&G	The difference is primarily due to the inclusion of the redesigned Long Term Incentive Plan and the adjustment to reduce employee count in the Interim Test Year.
Income Taxes	The changes described above also impacts Income Taxes as shown in Direct Schedule F-3 (IR), including related to the Interest Synchronization adjustment.

Line No.	Description	Calculation Note	Minnesota Jurisdiction		
			Proposed Test Year 2027	Interim Test Year 2027	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,708,687,461	$2,626,893,825	($81,793,635)
2	Operating Income Before AFUDC		$68,992,025	$73,580,412	$4,588,386
3	AFUDC		$18,881,429	$18,881,162	($267)
4	Operating Income	Line 2 + Line 3	$87,873,454	$92,461,574	$4,588,120
5	Rate of Return	Line 4 / Line 1	3.2441%	3.5198%	0.2757%
6	Required Rate of Return		7.6273%	7.5584%	(0.0689%)
7	Required Operating Income	Line 1 * Line 6	$206,599,719	$198,551,143	($8,048,576)
8	Operating Income Deficiency	Line 7 - Line 4	$118,726,264	$106,089,569	($12,636,695)
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$166,614,646	$148,880,924	($17,733,722)
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$754,108,669	$754,017,218	($91,451)
12	Required Percent Increase	Line 10 / Line 11	22.09%	19.75%	

RESIDENTIAL SERVICE

RATE CODES

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

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$9.00	$15.00
All kWh (¢/kWh)	10.772¢	11.261¢

0 kWh to 600 kWh discount for eligible customers -4.311¢

Plus any applicable Adjustments.

MINIMUM CHARGE

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

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

RESIDENTIAL SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh, along with being a low-income customer. A low-income customer is defined as eligible for the Low Income Home Energy Assistance Program ("LIHEAP") in Minnesota Power's billing system or a customer who has completed a self-declaration process. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

~~11.~~12. Eligible customers will receive the discount for a one year time period, at which point average monthly usage will be re-calculated to determine the continued eligibility for the following year.

~~12.~~13. Self-declaration for the low-income eligibility will require a renewal every two years in general and every four years for those on a fixed income.

~~13.~~14. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

~~14.~~15. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

CONTRACT PERIOD

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

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

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

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

TYPE OF SERVICE

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

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

DUAL FUEL PROGRAM OPTIONS

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

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

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)	
Small Service	7.949¢ per kWh
Large Service	7.949¢ per kWh

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

Energy Charge - Dual Fuel Plus	
Small Service	5.564¢ per kWh
Large Service	5.564¢ per kWh

Plus any applicable Adjustments.

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

Energy Charge	
All kWh (per kWh)	10.772¢

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

3. Interruption will normally occur at such times:

   (a) when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when the Company expects to incur a new system peak,
   (c) at such other times when, in the Company's opinion, system reliability is endangered,

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(d) when the Company performs necessary testing for certification of interruptibility of customers' loads.

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

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

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

RESIDENTIAL FIXED OFF-PEAK SERVICE

RATE CODES

24

APPLICATION

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

TYPE OF SERVICE

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

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

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RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge	
Small Service (per kWh)	5.564¢
Large Service (per kWh)	5.564¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

RESIDENTIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

RESIDENTIAL FIXED OFF-PEAK SERVICE

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

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

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

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

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

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$6.00
Off-Peak Energy Charge All kWh (per kWh)	3.200¢
On-Peak Energy Charge All kWh (per kWh)	11.431¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

RESIDENTIAL ELECTRIC VEHICLE SERVICE

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

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

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

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

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

GENERAL SERVICE

RATE CODES

25

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$15.00
Energy Charge for all kWh	9.848¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$15.00
Demand Charge for all kW	$6.50
Transmission Demand for all kW	$4.03
Energy Charge for all kWh	6.890¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

GENERAL SERVICE

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

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

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

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

GENERAL SERVICE

Customers whose monthly demand has been less than 10 kW during the past 12-month period and whose monthly consumption has not exceeded 2,500 kWh in three or more consecutive months during the same 12-month period will be identified and the 12-month history of such customer's kW and kWh requirements are reviewed. After review, where appropriate, a rate change will be made to a non-demand general service rate.

All customers exceeding the demand threshold criteria are required to be moved to the demand rates. Those not reaching the criteria are eligible to be removed from the demand rates.

PAYMENT

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

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

RATE CODES

29

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

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

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

DEMAND CHARGE CAP

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

PAYMENT

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

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

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

RATE CODES

30

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge for On-Peak ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge ($/kW) On-Peak Transmission Demand	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

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

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

PAYMENT

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

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

RATE CODES

31

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or

the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

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

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

DEMAND CHARGE CAP

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

PAYMENT

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

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

TYPE OF SERVICE

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

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

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)

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

Dual Fuel Plus

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge – Dual Fuel (standard)	
Small Service	7.915¢ per kWh
Large Service-Low Voltage	7.915¢ per kWh
Large Service-High Voltage	7.781¢ per kWh
Energy Charge – Dual Fuel Plus	
Small Service	5.523¢ per kWh
Large Service-Low Voltage	5.523¢ per kWh
Large Service-High Voltage	5.401¢ per kWh

Plus any applicable Adjustments.

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

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

Energy Charge	
All kWh (per kWh)	9.848¢ per kWh

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

CONTRACT PERIOD

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

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

SERVICE CONDITIONS

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

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.
3. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) when, in the Company's opinion, the reliability of the system is endangered, or
   (d) when the Company performs necessary testing of interruptibility of customer's loads.

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

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

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

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

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

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

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

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

RATE CODE

27

APPLICATION

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

TYPE OF SERVICE

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

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

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge	
Small Service - Low Voltage	5.523¢ per kWh
Large Service - Low Voltage	5.523¢ per kWh
Large Service - High Voltage	5.401¢ per kWh

Plus any applicable Adjustments.

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

MINIMUM CHARGE (Monthly)

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

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

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

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

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

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

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,050.00
All additional kW of Billing Demand ($/kW)	$9.25
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$6.07
Energy Charge	
All kWh (¢/kWh)	5.132¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

LARGE LIGHT AND POWER SERVICE

subject to a discount of 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

LARGE LIGHT AND POWER SERVICE

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~10.~~11. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

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

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

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

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

PAYMENT

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

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

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

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

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

ELECTRIC SERVICE AGREEMENTS

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

At a minimum, every ESA shall include the following:

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

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

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

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

(e) A confidentiality agreement; and

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

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other

party written notice of cancellation at least four years prior to the time such cancellation shall be effective.
The effective date of each ESA shall be subject to approval by the Commission.

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

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

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

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

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

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

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's

LARGE POWER SERVICE

available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

BASE RATES (MONTHLY)

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

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$244,334
All additional kW of Firm Demand ($/kW)	$24.00

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$8.49

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.164¢

Excess Energy Charge

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

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

~~2.~~3. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Charge.

LARGE POWER SERVICE

~~3.~~4. Capacity Revenue and Expense Adjustment. A capacity revenue and expense adjustment will be determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~4.~~5. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

~~6.~~7. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

~~7.~~8. CARE Low-Income Affordability Program Surcharge. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~8.~~9. Solar Energy Adjustment. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~9.~~10. Minnesota Policy Adjustment. The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

~~10.~~11. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~11.~~12. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

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

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive

demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

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

DEMAND

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

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

DEMAND NOMINATIONS

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

ENERGY

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

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

LARGE POWER SERVICE

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

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

LARGE POWER SURCHARGE

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

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply

the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

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

Energy Portion

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

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

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

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

LARGE POWER SERVICE

OPERATING PRACTICES

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

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$293,201
All additional kW of Non-Contract Billing Demand ($/kW)	$28.80

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$10.19

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.164¢

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

Plus any applicable Adjustments.

NON-CONTRACT LARGE POWER SERVICE

SERVICE VOLTAGE ADJUSTMENT

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge. Such Fuel Charge shall be applicable to Customer's Non-Contract Firm Energy only.

~~2.~~3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Minnesota Policy Adjustment: The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

NON-CONTRACT LARGE POWER SERVICE

~~8.~~9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

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

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

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

NON-CONTRACT BILLING DEMAND

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

NON-CONTRACT ENERGY

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

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy

NON-CONTRACT LARGE POWER SERVICE

to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

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

PURCHASED POWER SURCHARGE

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

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

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

Energy Portion
For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic

NON-CONTRACT LARGE POWER SERVICE

Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

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

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

SERVICE CONDITIONS

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

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

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

REGULATION AND JURISDICTION

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

NON-CONTRACT LARGE POWER SERVICE

schedules in effect from time to time.

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

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

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

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$12.92			
20,000 Lumens (400 watts)	MV400W	$20.57			
55,000 Lumens (1,000 watts)	MV1000W	$38.33			
Sodium Vapor Fixtures					
8,500 Lumens (100 watts)	SV100W	$11.34		$6.54	
14,000 Lumens (150 watts)	SV150W	$13.07			
23,000 Lumens (250 watts)	SV250W2	$18.54		$11.19	
45,000 Lumens (400 watts)	SV400W	$24.83		$11.87	
Metal Halide Fixtures					
17,000 Lumens (250 watts)	MH250W	$18.34			
28,800 Lumens (400 watts)	MH400W	$22.34		$13.24	
88,000 Lumens (1,000 watts)	MH1000W	$37.22		$24.18	
Light Emitting Diodes (LED)					
4,000 Lumens (48 watts or less)	LED48W	$11.41			
10,000 Lumens (71 watts or less)	LED71W	$11.93			
24,000 Lumens (184 watts or less)	LED184W	$20.61			
46,800 Lumens (320 watts or less)	LED320W	$31.26			
Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$13.00		$13.00	

OUTDOOR AND AREA LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	10.998¢

Plus any applicable Adjustments.

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

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

~~2.~~3. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

OUTDOOR AND AREA LIGHTING SERVICE

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

BURNING SCHEDULE

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

ENERGY TABLE

OUTDOOR AND AREA LIGHTING SERVICE

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

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

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

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

Option 1

COMPANY TO OWN AND MAINTAIN:

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

Option 2

Reserved for Future Use

Option 3

OUTDOOR AND AREA LIGHTING SERVICE

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

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

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include, but not be limited to, the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.
2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

OUTDOOR AND AREA LIGHTING SERVICE

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

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

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, will be at Customer's expense.

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

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

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

TERRITORY

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

APPLICATION

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

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$17.85		$13.34	
10,000 Lumens (250 watts)	MV250W			$16.95	
20,000 Lumens (400 watts)	MV400W	$24.28		$22.91	
55,000 Lumens (1,000 watts)	MV1000W2			$27.46	
Sodium Vapor Fixtures (Closed to New Installations)					
8,500 Lumens (100 watts)	SV100W	$15.77		$10.71	
14,000 Lumens (150 watts)	SV150W	$17.45		$15.08	
14,000 Lumens (150 watts)	SV150W-P			$9.11	
20,500 Lumens (200 watts)	SV200W	$21.58		$16.47	
23,000 Lumens (250 watts)	SV250W	$21.73		$17.79	
45,000 Lumens (400 watts)	SV400W	$26.69		$21.42	
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$15.86			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$19.88			
23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$26.56			

STREET AND HIGHWAY LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	10.998¢

Plus any applicable Adjustments.

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

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

~~2.~~3. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

The monthly capacity revenue and expense adjustment per fixture shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

STREET AND HIGHWAY LIGHTING SERVICE

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

~~9.~~10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

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

BURNING SCHEDULE

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

ENERGY TABLE

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

STREET AND HIGHWAY LIGHTING SERVICE

SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

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

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

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

Option 1

COMPANY TO OWN AND MAINTAIN:

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

Option 2

Reserved for Future Use

Option 3

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

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out fixtures and photo-electric controls and will clean or replace glassware at the time of fixture replacement. Customer shall be responsible for providing replacement

STREET AND HIGHWAY LIGHTING SERVICE

glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

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

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

STREET AND HIGHWAY LIGHTING SERVICE

and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

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

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

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

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

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

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

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

RESIDENTIAL SERVICE

RATE CODES

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

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$9.00	$15.00
All kWh (¢/kWh)	10.772¢	11.261¢

0 kWh to 600 kWh discount for eligible customers -4.311¢

Plus any applicable Adjustments.

MINIMUM CHARGE

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

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

RESIDENTIAL SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

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

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

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

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

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

PAYMENT

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

CONTRACT PERIOD

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

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

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

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

TYPE OF SERVICE

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

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

DUAL FUEL PROGRAM OPTIONS

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

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

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)	
Small Service	7.949¢ per kWh
Large Service	7.949¢ per kWh

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

Energy Charge - Dual Fuel Plus	
Small Service	5.564¢ per kWh
Large Service	5.564¢ per kWh

Plus any applicable Adjustments.

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

Energy Charge	
All kWh (per kWh)	10.772¢

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

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

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

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

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

PAYMENT

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

3. Interruption will normally occur at such times:

   (a) when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when the Company expects to incur a new system peak,
   (c) at such other times when, in the Company's opinion, system reliability is endangered,

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(d) when the Company performs necessary testing for certification of interruptibility of customers' loads.

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

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

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

RESIDENTIAL FIXED OFF-PEAK SERVICE

RATE CODES

24

APPLICATION

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

TYPE OF SERVICE

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

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

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RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge	
Small Service (per kWh)	5.564¢
Large Service (per kWh)	5.564¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

RESIDENTIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

PAYMENT

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

RESIDENTIAL FIXED OFF-PEAK SERVICE

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

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

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

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

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

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$6.00
Off-Peak Energy Charge	
All kWh (per kWh)	3.200¢
On-Peak Energy Charge	
All kWh (per kWh)	11.431¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

RESIDENTIAL ELECTRIC VEHICLE SERVICE

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

PAYMENT

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

1. The Residential Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible

RESIDENTIAL ELECTRIC VEHICLE SERVICE

for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

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

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

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

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

GENERAL SERVICE

RATE CODES

25

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$15.00
Energy Charge for all kWh	9.848¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$15.00
Demand Charge for all kW	$6.50
Transmission Demand for all kW	$4.03
Energy Charge for all kWh	6.890¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

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

DETERMINATION OF THE BILLING DEMAND

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

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

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

GENERAL SERVICE

Customers whose monthly demand has been less than 10 kW during the past 12-month period and whose monthly consumption has not exceeded 2,500 kWh in three or more consecutive months during the same 12-month period will be identified and the 12-month history of such customer's kW and kWh requirements are reviewed. After review, where appropriate, a rate change will be made to a non-demand general service rate.

All customers exceeding the demand threshold criteria are required to be moved to the demand rates. Those not reaching the criteria are eligible to be removed from the demand rates.

PAYMENT

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

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

RATE CODES

29

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

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

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

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

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

DETERMINATION OF THE BILLING DEMAND

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

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

DEMAND CHARGE CAP

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

PAYMENT

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

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

RATE CODES

30

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge for On-Peak ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge ($/kW) On-Peak Transmission Demand	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

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

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

HIGH VOLTAGE SERVICE

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

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

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

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

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

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

DETERMINATION OF THE BILLING DEMAND

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

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

PAYMENT

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

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

RATE CODES

31

APPLICATION

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

TYPE OF SERVICE

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

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.890¢
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

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

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

DETERMINATION OF THE BILLING DEMAND

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

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

DEMAND CHARGE CAP

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

PAYMENT

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

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

TYPE OF SERVICE

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

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

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)

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

Dual Fuel Plus

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge – Dual Fuel (standard)	
Small Service	7.915¢ per kWh
Large Service-Low Voltage	7.915¢ per kWh
Large Service-High Voltage	7.781¢ per kWh
Energy Charge – Dual Fuel Plus	
Small Service	5.523¢ per kWh
Large Service-Low Voltage	5.523¢ per kWh
Large Service-High Voltage	5.401¢ per kWh

Plus any applicable Adjustments.

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

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

Energy Charge	
All kWh (per kWh)	9.848¢ per kWh

MINIMUM CHARGE (Monthly)

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

PAYMENT

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

CONTRACT PERIOD

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

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

SERVICE CONDITIONS

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

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.
3. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) when, in the Company's opinion, the reliability of the system is endangered, or
   (d) when the Company performs necessary testing of interruptibility of customer's loads.

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

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

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

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

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

8. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

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

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

RATE CODE

27

APPLICATION

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

TYPE OF SERVICE

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

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

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge	
Small Service - Low Voltage	5.523¢ per kWh
Large Service - Low Voltage	5.523¢ per kWh
Large Service - High Voltage	5.401¢ per kWh

Plus any applicable Adjustments.

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

MINIMUM CHARGE (Monthly)

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

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

PAYMENT

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

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

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

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

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

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,050.00
All additional kW of Billing Demand ($/kW)	$9.25
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$6.07
Energy Charge	
All kWh (¢/kWh)	5.132¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

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

subject to a discount of 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the

price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

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

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

DETERMINATION OF THE BILLING DEMAND

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

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

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

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

PAYMENT

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

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

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

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

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

ELECTRIC SERVICE AGREEMENTS

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

At a minimum, every ESA shall include the following:

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

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

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

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

(e) A confidentiality agreement; and

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

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other

party written notice of cancellation at least four years prior to the time such cancellation shall be effective.
The effective date of each ESA shall be subject to approval by the Commission.

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

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

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

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

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

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

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's

LARGE POWER SERVICE

available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

BASE RATES (MONTHLY)

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

Demand Charge	
A single application for the first 10,000 kW or less of Firm Demand	$244,334
All additional kW of Firm Demand ($/kW)	$24.00
Transmission Demand Charge	
All kW of Firm Demand ($/kW)	$8.49
Energy Charge	
All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.164¢

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

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

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

LARGE POWER SERVICE

4. Capacity Revenue and Expense Adjustment. A capacity revenue and expense adjustment will be determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

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

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

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

MEASURED AND ADJUSTED DEMAND

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

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the

LARGE POWER SERVICE

month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

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

DEMAND

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

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

DEMAND NOMINATIONS

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

ENERGY

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

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

LARGE POWER SERVICE

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

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

LARGE POWER SURCHARGE

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

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the

LARGE POWER SERVICE

power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

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

Energy Portion

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

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

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

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

OPERATING PRACTICES

LARGE POWER SERVICE

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

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

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

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

TYPE OF SERVICE

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

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$293,201
All additional kW of Non-Contract Billing Demand ($/kW)	$28.80

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$10.19

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.164¢

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

Plus any applicable Adjustments.

NON-CONTRACT LARGE POWER SERVICE

SERVICE VOLTAGE ADJUSTMENT

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

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

3. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

9. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the

price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

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

MEASURED AND ADJUSTED DEMAND

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

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

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

NON-CONTRACT BILLING DEMAND

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

NON-CONTRACT ENERGY

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

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

involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

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

PURCHASED POWER SURCHARGE

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

Capacity Portion

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

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

Energy Portion

For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined

monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

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

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

SERVICE CONDITIONS

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

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

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

REGULATION AND JURISDICTION

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

NON-CONTRACT LARGE POWER SERVICE

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

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

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

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$12.92			
20,000 Lumens (400 watts)	MV400W	$20.57			
55,000 Lumens (1,000 watts)	MV1000W	$38.33			
Sodium Vapor Fixtures					
8,500 Lumens (100 watts)	SV100W	$11.34		$6.54	
14,000 Lumens (150 watts)	SV150W	$13.07			
23,000 Lumens (250 watts)	SV250W2	$18.54		$11.19	
45,000 Lumens (400 watts)	SV400W	$24.83		$11.87	
Metal Halide Fixtures					
17,000 Lumens (250 watts)	MH250W	$18.34			
28,800 Lumens (400 watts)	MH400W	$22.34		$13.24	
88,000 Lumens (1,000 watts)	MH1000W	$37.22		$24.18	
Light Emitting Diodes (LED)					
4,000 Lumens (48 watts or less)	LED48W	$11.41			
10,000 Lumens (71 watts or less)	LED71W	$11.93			
24,000 Lumens (184 watts or less)	LED184W	$20.61			
46,800 Lumens (320 watts or less)	LED320W	$31.26			
Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$13.00		$13.00	

Approved by: Leah N. Peterson
Leah N. Peterson
Director – Customer Analytics and Market Settlements

OUTDOOR AND AREA LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	10.998¢

Plus any applicable Adjustments.

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

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

3. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

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

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

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

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

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

OUTDOOR AND AREA LIGHTING SERVICE

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.
9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

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

PAYMENT

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

BURNING SCHEDULE

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

ENERGY TABLE

OUTDOOR AND AREA LIGHTING SERVICE

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

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

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

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

Option 1

COMPANY TO OWN AND MAINTAIN:

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

Option 2

Reserved for Future Use

Option 3

OUTDOOR AND AREA LIGHTING SERVICE

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

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

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include, but not be limited to, the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.
2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

OUTDOOR AND AREA LIGHTING SERVICE

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

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

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, will be at Customer's expense.

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

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

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

TERRITORY

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

APPLICATION

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

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$17.85		$13.34	
10,000 Lumens (250 watts)	MV250W			$16.95	
20,000 Lumens (400 watts)	MV400W	$24.28		$22.91	
55,000 Lumens (1,000 watts)	MV1000W2			$27.46	
Sodium Vapor Fixtures (Closed to New Installations)					
8,500 Lumens (100 watts)	SV100W	$15.77		$10.71	
14,000 Lumens (150 watts)	SV150W	$17.45		$15.08	
14,000 Lumens (150 watts)	SV150W-P			$9.11	
20,500 Lumens (200 watts)	SV200W	$21.58		$16.47	
23,000 Lumens (250 watts)	SV250W	$21.73		$17.79	
45,000 Lumens (400 watts)	SV400W	$26.69		$21.42	
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$15.86			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$19.88			
23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$26.56			

STREET AND HIGHWAY LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	10.998¢

Plus any applicable Adjustments.

ADJUSTMENTS

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

   There shall also be added an Interim Rate Adjustment equal to 19.75% of the billing for electric service.

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

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

3. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

   The monthly capacity revenue and expense adjustment per fixture shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

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

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

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

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

STREET AND HIGHWAY LIGHTING SERVICE

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

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

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

PAYMENT

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

BURNING SCHEDULE

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

ENERGY TABLE

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

STREET AND HIGHWAY LIGHTING SERVICE

MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

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

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

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

Option 1

COMPANY TO OWN AND MAINTAIN:

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

Option 2

Reserved for Future Use

Option 3

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

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out fixtures and photo-electric controls and will clean or replace glassware at the time of fixture replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned

STREET AND HIGHWAY LIGHTING SERVICE

equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

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

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

CONTRACT PERIOD

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

SERVICE CONDITIONS

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

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

STREET AND HIGHWAY LIGHTING SERVICE

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

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

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

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

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

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

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

Notice to:
COUNTIES AND MUNICIPALITIES

Under Minn. Stat. § 216B.16, Subd. 1

minnesota power

AN ALLETE COMPANY

On XXXXX XX, 2026, the Minnesota Public Utilities Commission ("Commission") accepted as of XXXXX XX, 2026, Minnesota Power's application for a general increase in rates for electric service provided to customers in the state of Minnesota of approximately $134.4 million, or about 17.83%, pursuant to Minn. Stat. § 216B.16, when combined with rider decreases under the Minnesota Policy Adjustment line item as some rider costs move to base rates. Without the decrease to the Minnesota Policy Adjustment, the increase to base rates is $166.6 million, or a 22.09% overall increase. Depending on customer class and usage, the actual percentage will vary based upon final approval by the Commission. The Commission will make its decision regarding final rates in late 2027.

In accordance with Minn. Stat. § 216B.16, subd. 2, the Commission has suspended proposed final rates to allow the Commission time to evaluate the application. In accordance with Minn. Stat. § 216B.16, subd. 3, the Commission has authorized a total interim rate increase net of offsetting riders under the Minnesota Policy Adjustment of approximately $116.7 million or about 15.48% to be effective January 1, 2027 and to remain in effect until a final rate level is determined. Without the reduction from the offsetting rider change during the interim rate period, Minnesota Power electric customers' bills would be approximately 19.75% higher on an overall net basis, depending on service class.

Examples of the effect of these net increases on typical bills are as follows:

Proposed change in monthly electricity costs

Customer Classification	Avg. monthly kWh usage	Previous monthly cost	Interim monthly increase	Proposed final monthly increase*
Residential	663	$101	$15	$24
Residential Dual Fuel	905	$109	$17	$11
General Service	2,431	$366	$58	$87
Commercial & Industrial Dual Fuel	2,614	$304	$48	$30
Large Light & Power	238,422	$26,665	$4,175	$5,758
Large Power	490,769,573	$3,740,585	$567,280	$807,750
Street & Area Lighting	157	$70	$13	$17

*Monthly increases include all line items on bills except sales taxes and municipal franchise fees, and may vary by individual customer based on usage characteristics.

The rate levels upon which the previous monthly costs are based were authorized in Docket No. E015/GR-23-155.

The Commission will determine the amount of increase in rates it will allow in late 2027, and final rates reflecting that determination will be implemented thereafter. If the final rate level is less than the interim rate level, the amount collected during the interim period attributable to that difference will be refunded to customers with interest.

The proposed rate schedules and a comparison of present and proposed rates may be examined by the public during normal business hours at the Minnesota Department of Commerce, 85 7th Place East, Suite 280, St. Paul, MN 55101, Telephone: 651-539-1500

They are also available on the internet at:

Minnesota Power: www.mnpower.com/RateRequest

Commission: www.mn.gov/puc
Docket Number E015/GR-216-199

The Minnesota Department of Commerce, among other parties, will review Minnesota Power's books and records in this proceeding.

An Administrative Law Judge will schedule public hearings. Customers will be notified when the hearings are scheduled. Public notice of hearing dates and locations will be published in local newspapers in Minnesota Power's service area.

Persons who wish to formally intervene or testify in this case should contact the Administrative Law Judge, Minnesota Office of Administrative Hearings, 600 North Robert St., St. Paul, MN 55101.

The MPUC welcomes customer comments

Minnesota Public Utilities Commission

121 7th Place East, Suite 350
St. Paul, MN 55101
651-296-0406 or 1-800-657-3782

mn.gov/puc
Select "Get Involved" and then "Make a public comment," Enter the docket (26-199) with your comments.

Email comments to
consumer.puc@state.mn.us

How to learn more

Minnesota Power's current and proposed rate schedules are available at:

Minnesota Power

www.mnpower.com/RateRequest
1-800-228-4966

Minnesota Department of Commerce

Energy Division
85 7th Place East, Suite 280
St. Paul, MN 55101
651-539-1500

mn.gov/puc
Select eDockets, then type 26 in the year field, type 199 in the number field, select Search, and the list of documents will appear on the next page.

Citizens with hearing or speech disabilities may call through their preferred Telecommunications Relay Service.

minnesota power
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mnpower.com/RateRequest

People who communicate in a language other than English can request translation services by calling Minnesota Power at 800-228-4966. We also offer a translation option at www.mnpower.com.

26215 10.31.26

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Interim change in electric rates

Your Minnesota Power bill is changing.
Effective January 1, 2027

Minnesota Power has asked the Minnesota Public Utilities Commission (MPUC) for an increase in electricity rates.

Our proposed increase to customer bills is about 17.83% when compared to 2026 levels, resulting in a revenue increase of $134.4 million. Included in the proposal is a 22.09% increase in base rates, or about $166.6 million annually, and a 4.27% or $32.2 million annual reduction in the Minnesota Policy Adjustment line item on your bill. While the MPUC reviews our request, state law allows Minnesota Power to collect higher rates on an interim (temporary) basis. The MPUC has approved an overall interim rate increase of about 15.48%, or $116.7 million in annual Minnesota Power revenue, when combined with decreases in the Minnesota Policy Adjustment line item. The interim rate increase is effective for service rendered on or after January 1, 2027.

The rate increase appears on your bill as "Interim Rate Adjustment." It applies to all major items on your bill. For residential and small general service customers, those charges include the monthly minimum charge and energy charges. For all other customers, the increase applies to the customer charge, energy charges, and the demand charge. The offsetting rider decrease appears on your bill in the Minnesota Policy Adjustment line.

The MPUC will have up to 15 months to review our request and will make its decision regarding final rates by late 2027. If final rates are lower than interim rates, Minnesota Power will refund customers the difference with interest. If final rates are higher than interim rates, Minnesota Power will not charge customers the difference.

Why is Minnesota Power asking for an increase?

Our current rates were set in MPUC Docket No. E015/GR-23-155. Since then, we've experienced cost increases due to inflation as we've invested in transmission, distribution and generation infrastructure and cleaner energy resources to ensure safe, reliable and cleaner sources of energy for customers. State regulators will review these expenses and decide how Minnesota Power may recover those costs.

What is the process for reviewing Minnesota Power's request?

The MPUC, the Minnesota Department of Commerce – Division of Energy Resources, the Office of the Attorney General – Residential Utilities and Antitrust Division, public interest groups, and customers will review and investigate our proposal.

The MPUC will hold public hearings about our rate request. Customers and others will be able to comment on our rate request at the public hearings. You may add verbal comments, written comments, or both into the record.

Notice of the public hearing dates and locations will be published in local newspapers, in bill inserts and online at **mnpower.com/RateRequest** and **mn.gov/puc**.

How will these rate changes affect monthly bills?

The proposed rate increase will affect individual monthly bills differently, depending on the amount of electric usage and customer type. The table below shows the average, interim and proposed rate impacts inclusive of the Minnesota Policy Adjustment line item decreases for each customer type compared to previous rates in 2026.

Customer Classification	Avg. monthly kWh usage	Avg. current monthly cost	Net interim monthly increase	Proposed final net monthly increase
Residential	663	$101	$15	$24
Residential Dual Fuel	905	$109	$17	$11
General Service	2,431	$366	$58	$87
Commercial & Industrial Dual Fuel	2,614	$304	$48	$30
Large Light & Power	238,422	$26,665	$4,175	$5,758
Large Power	490,769,573	$3,740,585	$567,280	$807,750
Street & Area Lighting	157	$70	$13	$17

RATE INCREASE NOTICE

Month 2027

Minnesota Power has asked the Minnesota Public Utilities Commission (MPUC) for permission to increase its electric rates by approximately $134.4 million, or about 17.83% overall, when combined with rider decreases under the Minnesota Policy Adjustment line item as some rider costs move to base rates. The base rate increase, excluding the decrease to the Minnesota Policy Adjustment, results in an increase of $166.6 million, or approximately 22.09% overall. Depending on customer class and usage, the actual percentage will vary based upon final approval by the MPUC. The MPUC will make its decision regarding final rates in late 2027.

Public Comment

Administrative Law Judge XXXXXXXXX has scheduled public hearings to give customers an opportunity to present their views regarding Minnesota Power's recently filed retail rate case (MPUC Docket No. E-015/GR-26-199 and OAH Docket No. XX-XXXX-XXXXX). Any Minnesota Power customer or other person may attend or provide comments at the hearings. You are invited to comment on the adequacy and quality of Minnesota Power's service, the level of rates or other related matters. You do not need to be represented by an attorney.

Public Hearings Schedule

DATE	TIME	LOCATION	
XXXXX	**00:00**	XXXXX	Address
	00:00	XXXXX	Address
XXXXX	**00:00**	XXXXX	Address
	00:00	XXXXX	Address
	00:00	XXXXX	Address
XXXXX	**00:00**	Virtual Only	LINK

Written comments may be sent to Administrative Law Judge XXXXXXXX, Office of Administrative Hearings, PO Box 64620, St. Paul, MN 55164 or by email to XXXXXX@state.mn.us. Written comments are most effective when they include: 1) the section of Minnesota Power's proposal you are addressing, 2) your specific recommendations, 3) the reason for your recommendations, and 4) Docket No. OAH XX-XXXX-XXXXX and MPUC E015/GR-26-199.

Important: Comments will be made available to the public on the MPUC website, except in limited circumstances consistent with the Minnesota Government Data Practices Act. The MPUC does not edit or delete personal identifying information from submissions.

Accessibility Accommodations

If you need any reasonable accommodation to enable you to fully participate in these public hearings (i.e., sign language or foreign language interpreter, wheelchair accessibility, or large-print materials), please contact the Office of Administrative Hearings at 651-361-7834 at least one week in advance of the meeting. **Customers with hearing or speech disabilities may call through Minnesota Relay 1-800-627-3529 or 7-1-1.**

Evidentiary Hearings

Formal evidentiary hearings on Minnesota Power's proposal are scheduled to start on Month XX, 2027, at XX:XX x.m., in the Large Hearing Room, Minnesota Public Utilities Commission, 121 Seventh Place East, Suite 350, St. Paul, MN. The purpose of the evidentiary hearings is to allow Minnesota Power, the Minnesota Department of Commerce–Division of Energy Resources, the Office of Attorney General–Residential Utilities and Antitrust Division and others to present testimony and to cross-examine each other's witnesses on the proposed rate increase.

Anyone who wishes to formally intervene in this case should contact the Administrative Law Judge, XXXXXXXX, at the Office of Administrative Hearings, PO Box 64620, St. Paul, MN 55164 or by email to XXXXXX@state.mn.us.

Effect of Rate Changes

Below are examples of the effect of the proposed increase on typical bills of Minnesota Power's customers. Individual changes may be higher or lower depending on actual electricity usage.

Customer Classification	Avg. monthly kWh usage	Avg. current monthly cost	Net interim monthly increase	Proposed final net monthly increase*
Residential	663	$101	$15	$24
Residential Dual Fuel	905	$109	$17	$11
General Service	2,431	$366	$58	$87
Commercial & Industrial Dual Fuel	2,614	$304	$48	$30
Large Light & Power	238,422	$26,665	$4,175	$5,758
Large Power	490,769,573	$3,740,585	$567,280	$807,750
Street & Area Lighting	157	$70	$13	$17

*Monthly increases include all line items on bills except sales taxes and municipal franchise fees, and may vary by customer based on usage.

The rate changes described in this notice have been requested by Minnesota Power. The MPUC may either grant or deny the requested changes, in whole or in part, and may grant a lesser or greater increase than that requested for any class or classes of service.

For More Information

You may examine our current and proposed rate schedules and our request for new rates by visiting our website at www.mnpower.com/RateRequest. Or, you may contact the Minnesota Department of Commerce–Energy Division at 85 7th Place East, Suite 280, St. Paul, MN 55101, Phone: 651-539-1500. Customers with hearing or speech disabilities may call through Minnesota Relay 800-627-3529 or 7-1-1. Web: mn.gov/puc (search by docket number: select 26 in the year field, enter 199 in the number field, click on search, and the list of documents will appear on the next page).

Customers may submit comments with the MPUC (Enter docket 26-199 with your comment):

Online: Visit mn.gov/puc, select "Get Involved" and then "Make a public comment"

Email: consumer.puc@state.mn.us

Mail: 121 7th Place East, Suite 350, St. Paul, MN 55101

Phone: 651-296-0406 or 1-800-657-3782

Need help translating this text? People who communicate in a language other than English can request translation services by calling Minnesota Power at 800-228-4966. We also offer a translation option at mnpower.com.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota	Docket No. E015/GR-26-199
	AGREEMENT AND UNDERTAKING

Minnesota Power, in conjunction with the Notice and Petition for Interim Rates filed with the Minnesota Public Utilities Commission ("Commission"), makes the following unqualified agreement concerning refunding any portion of the requested increase in rates determined by the Commission to be unreasonable.

Pursuant to Minn. R. 7825.3300, Minnesota Power hereby agrees and undertakes to refund to its customers the amount, if any, collected during the interim rate period, plus interest at the current rate determined by the Commission, computed from the effective date of the interim rates through the date of refund. The refund shall be made in accordance with Minn. Stat. § 216B.16, subd. 3, and in a manner approved by the Commission.

In addition, Minnesota Power agrees to keep such records of sales and billings under the proposed interim rates as will be necessary to compute any potential refund.

This Agreement and Undertaking is made pursuant to authority granted by the Board of Directors of ALLETE, Inc.

Dated: November 2, 2026

Respectfully submitted,

Joshua J. Skelton
ALLETE Vice President & Chief Operating Officer – Minnesota Power
30 West Superior Street
Duluth, MN 55802

Subscribed to before me this 2nd day of November, 2026

Notary Public

AMY M HONKALA
NOTARY PUBLIC
MINNESOTA
My Commission Expires January 31st 2028

CERTIFICATION

As required by the Minnesota Public Utilities Commission's Statement of Policy on Interim Rates dated April 14, 1982, I hereby certify and affirm that the petition of Minnesota Power for approval of Proposed Interim Rates and Final Rates is in compliance with Minnesota Statutes.

Dated: November 2, 2026

Respectfully submitted,

Joshua J. Skelton
ALLETE Vice President & Chief Operating Officer – Minnesota Power
30 West Superior Street
Duluth, MN 55802

Subscribed to before me this 2nd day of November, 2026

Notary Public

AMY M HONKALA
NOTARY PUBLIC
MINNESOTA
My Commission Expires January 31st 2028

LIST OF COUNTIES AND CITIES

Entity	Address	City	State	Zip
Agram Township Clerk	23647 118th St	Pierz	MN	56364
Akeley City Clerk	PO Box 67	Akeley	MN	56433
Akeley Township Clerk	15 Broadway St W	Akeley	MN	56433
Alborn Township Clerk	6388 Hwy 7	Alborn	MN	55702
Aldrich City Clerk	PO Box 152	Aldrich	MN	56434
Arbo Township Clerk	33292 Arbo Hall Rd	Grand Rapids	MN	55744
Askov City Clerk	PO Box 245	Askov	MN	55704
Atkinson Township Clerk	2721 Hansen Rd	Carlton	MN	55718
Aurora City Clerk	PO Box 160	Aurora	MN	55705
Babbitt City Clerk	71 S Dr	Babbitt	MN	55706
Backus City Clerk	PO Box 44	Backus	MN	56435
Balkan Township	PO Box 66	Chisholm	MN	55719
Barnum City Clerk	3842 Main St	Barnum	MN	55707
Bay Lake Township	13861 County Rd 10	Deerwood	MN	56444
Becker County Administrator	915 Lake Ave	Detroit Lakes	MN	56501
Becker County Commissioners	915 Lake Ave	Detroit Lakes	MN	56501
Belle Prairie Township Clerk	16515 203rd St	Little Falls	MN	56345
Bellevue Township Clerk	20484 Kettle Rd	Royalton	MN	56373
Benton County Administrator	PO Box 129	Foley	MN	56329
Benton County Commissioners	531 Dewey St	Foley	MN	56329
Bertha City Clerk	208 2nd Ave NW	Bertha	MN	56437
Bigfork City Clerk	200 Main Ave	Bigfork	MN	56628
Biwabik City Administrator	PO Box 529	Biwabik	MN	55708
Blackhoof Township Clerk	2391 County Rd 105	Barnum	MN	55707
Bois Forte Tribal Government	5344 Lakeshore Dr	Nett Lake	MN	55772
Bovey City Clerk	402 2nd St	Bovey	MN	55709
Bowlus City Clerk	PO Box 98	Bowlus	MN	56314
Breitung Township Clerk	PO Box 56	Soudan	MN	55782
Brevator Township Clerk	PO Box 623	Cloquet	MN	55720
Brookston City Clerk	PO Box 304	Brookston	MN	55711
Browerville City Clerk	PO Box 247	Browerville	MN	56438
Bruce Township Hall	26234 285th Ave	Long Prairie	MN	56347
Bruno City Clerk	PO Box 112	Bruno	MN	55712
Bruno Township Clerk	PO Box 112	Bruno	MN	55712
Buckman City Clerk	PO Box 609	Buckman	MN	56317
Buckman Township Clerk	5120 260th Ave	Royalton	MN	56373
Buhl City Clerk	300 Jones Ave	Buhl	MN	55713
Burtrum City Clerk	PO Box 12	Burtrum	MN	56384
Calumet City Clerk	932 Gary St	Calumet	MN	55716
Carlton City Clerk	310 Chestnut Avenue	Carlton	MN	55718
Canosia Township Clerk	4896 Midway Rd	Duluth	MN	55811
Carlton City Clerk	310 Chestnut Ave	Carlton	MN	55718
Carlton County Commissioners	PO Box 130	Carlton	MN	55718
Carlton County Coordinator	1307 Cloquet Ave, Ste. 1	Carlton	MN	55720
Cass County Administrator	PO Box 3000	Walker	MN	56484
Cass County Commissioners	303 Minnesota Ave W	Walker	MN	56484
Cherry Township Clerk	9831 Hwy 37	Iron	MN	55751

LIST OF COUNTIES AND CITIES

Chickamaw Beach City Clerk	6775 Indian Trl Ln	Chickamaw Beach	MN	56474
Chisolm City Administrator	316 W Lake St	Chisholm	MN	55719
Clarissa City Clerk	202 Main St W	Clarissa	MN	56440
Clinton Township Clerk	PO Box 147	Iron	MN	55751
Cloquet City Administrator	101 - 14th St	Cloquet	MN	55720
Cohasset City Deputy Clerk	305 NW First Ave	Cohasset	MN	55721
Coleraine City Clerk	PO Box 670	Coleraine	MN	55722
Crosby City Clerk	2 Second St SW	Crosby	MN	56441
Crow Wing County Administrator	326 Laurel St, Ste. 13	Brainerd	MN	56401
Crow Wing County Commissioners	326 Laurel St, Ste. 13	Brainerd	MN	56401
Cuyuna City Clerk	PO Box 536	Deerwood	MN	56444
Deer River City Deputy Clerk	PO Box 70	Deerwood	MN	56636
Deerwood City Clerk	PO Box 187	Deerwood	MN	56444
Denham City Clerk	8624 Ballfield Rd	Sturgeon Lake	MN	55783
Duluth City Clerk	318 City Hall	Duluth	MN	55802
Duluth Township Clerk	6092 Homestead Rd	Duluth	MN	55804
Eagle Bend City Clerk	PO Box 215	Eagle Bend	MN	56446
East Gull Lake City Administrator	10790 Squaw Point Rd	East Gull Lake	MN	56401
Elmdale City Clerk	5015 20th St	Holdingford	MN	56340
Ely City Clerk	209 E Chapman St	Ely	MN	55731
Eveleth City Administrator	413 Pierce St	Eveleth	MN	55734
Fall Lake Township Clerk	PO Box 244	Ely	MN	55731
Fayal Town Clerk	4375 Shady Ln	Eveleth	MN	55734
Finlayson Township Clerk	24193 Wooder Cir	Finlayson	MN	55735
Flensburg City Clerk	PO Box 70	Flensburg	MN	56328
Floodwood City Administrator	111 W. 8th Avenue	Floodwood	MN	55736
Floodwood City Administrator	111 W. 8th Ave	Floodwood	MN	55736
Fond Du Lac Reservation	1720 Big Lake Rd	Cloquet	MN	55720
Fort Ripley City Clerk	PO Box 155	Fort Ripley	MN	56449
Fredenberg Township Clerk	5104 Fish Lake Rd	Duluth	MN	55803
Genola City Clerk	13883 Hwy 25	Pierz	MN	56364
Gilbert City Clerk	PO Box 548	Gilbert	MN	55741
Gnesen Township	6356 Howard Gnesen Rd	Duluth	MN	55803
Grand Lake Township Clerk	PO Box 1023	Twig	MN	55791
Grand Rapids City Clerk	420 N. Pokegama Ave	Grand Rapids	MN	55744
Great Scott Township Clerk	PO Box 277	Kinney	MN	55758
Green Prairie Township Clerk	14513 190th St	Little Falls	MN	56345
Greenway Township Clerk	PO Box 173	Marble	MN	55764
Grey Eagle City Clerk	PO Box 116	Grey Eagle	MN	56336
Grey Eagle Township Clerk	PO Box 202	Grey Eagle	MN	56336
Hackensack City Clerk	PO Box 490	Hackensack	MN	56452
Henrietta Township Clerk	PO Box 81	Park Rapids	MN	56470
Hermantown City Clerk	5105 Maple Grove Rd	Hermantown	MN	55811
Hewitt City Clerk	509 W 3rd Ave	Hewitt	MN	56453
Hibbing City Administrator	401 E 21st St	Hibbing	MN	55746
Hoyt Lakes City Clerk	206 Kennedy Memorial Dr	Hoyt Lakes	MN	55750
Hubbard County Administrator	301 Ct Ave	Park Rapids	MN	56470
Hubbard County Commissioners	301 Ct Ave	Park Rapids	MN	56470
Hubbard Township Clerk	11757 County 106	Park Rapids	MN	56470

LIST OF COUNTIES AND CITIES

Ideal Township	35458 Butternut Point Rd	Pequot Lakes	MN	56472
Industrial Township Clerk	PO Box 4	Saginaw	MN	55779
International Falls City Administrator	600 Fourth St	International Falls	MN	56649
Iron Junction City Clerk	4141 Merritt Ave	Iron	MN	55751
Iron Range Township Clerk	PO Box 96	Taconite	MN	55786
Irondale Township Clerk	19121 County Rd 12	Ironton	MN	56455
Ironton City Clerk	PO Box 97	Ironton	MN	56455
Itasca County Administrator	123 NE 4th St	Grand Rapids	MN	55744
Itasca County Commissioners	123 Fourth St NE	Grand Rapids	MN	55744
Jenkins City Clerk	33861 Cottage Ave	Jenkins	MN	56474
Jenkins Township Clerk	PO Box 523	Pequot Lakes	MN	56472
Kanabec County Commissioners	317 Maple Ave E, Ste. 181	Mora	MN	55051
Kanabec County Coordinator	317 Maple Ave E, Ste. 181	Mora	MN	55051
Keewatin City Clerk	PO Box 190	Keewatin	MN	55753
Kerrick City Clerk	PO Box 47	Kerrick	MN	55756
Kinney City Clerk	400 Main St	Kinney	MN	55758
Koochiching County Administrator	715 Fourth St	International Falls	MN	56649
Koochiching County Commissioners	715 Fourth St	International Falls	MN	56649
Lake County Administrator	601 Third Ave	Two Harbors	MN	55616
Lake County Commissioners	601 Third Ave	Two Harbors	MN	55616
Lake Shore City Clerk	8583 Interlachen Rd	Lake Shore	MN	56468
Lakewood Township Clerk	3110 Strand Rd	Duluth	MN	55803
Lastrup City Clerk	PO Box 55	Lastrup	MN	56364
Lavell Township Clerk	2189 Hwy 5	Hibbing	MN	55746
Leech Lake Band Of Ojibwe	190 Sailstar Dr NW	Cass Lake	MN	56633
Leonidas City Clerk	201 1st St N	Eveleth	MN	55734
Little Falls City Administrator	PO Box 244	Little Falls	MN	56345
Little Falls Township Clerk	20313 Hwy 27	Little Falls	MN	56345
Little Sauk Township Clerk	18557 County 11	Long Prairie	MN	56347
Lone Pine Township Clerk	31469 E. Shore Dr	Pengilly	MN	55775
Long Prairie City Clerk	615 Lake St S	Long Prairie	MN	56347
Long Prairie Township Clerk	23607 271st Ave	Long Prairie	MN	56347
Mahtowa Township Clerk	2790 1st St	Carlton	MN	55707
Marble City Clerk	302 Alice Ave	Marble	MN	55764
Mckinley City Clerk	PO Box 2088	Mckinley	MN	55741
Meadowlands City Clerk	PO Box 128	Meadowlands	MN	55765
Menahga City Administrator	115 2nd St NE	Menagha	MN	56464
Midway Township Clerk	PO Box 1008	Duluth	MN	55810
Mille Lacs Band Of Ojibwe	43408 Oodena Dr	Onamia	MN	56359
Mille Lacs County Administrator	635 Second St SE	Milaca	MN	56353
Mille Lacs County Commissioners	635 Second St SE	Milaca	MN	56353
Moose Lake City Administrator	412 Fourth St	Moose Lake	MN	55767
Moose Lake Township Clerk	PO Box 870	Moose Lake	MN	55767
Morrison County Administrator	213 First Ave SE	Little Falls	MN	56345
Morrison County Commissioners	213 First Ave SE	Little Falls	MN	56345
Motley City Clerk	316 Hwy 10 S	Motley	MN	55466
Mountain Iron City Administrator	8586 Enterprise Dr S	Mountain Iron	MN	55768
Nashwauk City Clerk	301 Central Ave	Nashwauk	MN	55769
Nevis City Clerk	104 Main St W	Nevis	MN	56467

LIST OF COUNTIES AND CITIES

Nimrod City Clerk	PO Box 943	Nimrod	MN	56478
Nisswa City Clerk	PO Box 410	Nisswa	MN	56468
Normanna Township Clerk	6472 French River Rd	Duluth	MN	55804
Osakis City Clerk	14 Nokomis St E	Osakis	MN	56360
Otter Tail County Administrator	520 First Ave W	Fergus Falls	MN	56537
Otter Tail County Commissioners	121 W Junius Ave	Fergus Falls	MN	56537
Park Rapids City Clerk	212 W Second St	Park Rapids	MN	56470
Partridge Township Clerk	67947 Sunrise Rd	Bruno	MN	55712
Pequot Lakes City Clerk	4638 Mian St	Pequot Lakes	MN	56472
Perch Lake Township Clerk	2779 Big Lake Rd	Cloquet	MN	55720
Pierz City Clerk	PO Box 367	Pierz	MN	56364
Pike Creek Township Clerk	15494 110th Ave	Little Falls	MN	56345
Pillager City Administrator	306 Elm Ave W	Pillager	MN	56473
Pine County Administrator	635 Northridge Dr. NW STE 200	Pine City	MN	55063
Pine County Commissioners	635 Northridge Drive NW	Pine City	MN	55063
Pine River City Clerk	PO Box 87	Pine River	MN	56474
Powers Township Clerk	850 E Horseshoe Dr NW	Backus	MN	56435
Proctor City Administrator	100 Pionk Dr	Proctor	MN	55810
Ranier City Administrator	PO Box 186	Ranier	MN	56668
Randall City Clerk	PO Box 229	Randall	MN	56475
Ranier City Administrator	PO Box 186	Ranier	MN	56668
Rice City Clerk	PO Box 179	Rice	MN	56367
Rice Lake City Clerk	4107 W Beyer Rd	Duluth	MN	55803
Round Prairie Township Clerk	25442 204th St	Long Prairie	MN	56347
Rutledge City Clerk	PO Box 124	Rutledge	MN	55795
Sandstone City Administrator	PO Box 641	Sandstone	MN	55072
Shingobee Township Clerk	PO Box 34	Walker	MN	56484
Sebeka City Clerk	PO Box 305	Sebeka	MN	56477
Silver Bay City Administrator	7 Davis Dr	Silver Bay	MN	55614
Solway Township Clerk	4029 Munger Shaw Rd	Cloquet	MN	55720
St. Anthony City Clerk	3301 Silver Lake Rd	St. Anthony	MN	55418
St. Louis County Administrator	100 N. 5th Ave W, RM 202	Duluth	MN	55802
St. Louis County Commissioners	100 N. 5th Ave W RM 202	Duluth	MN	55802
St. Rosa City Clerk	41545 County Rd 167	Melrose	MN	56352
Staples City Clerk	122 Sixth St Ne, Ste. 1	Staples	MN	56479
Stearns County Administrator	705 Courthouse Sq, RM 121	St. Cloud	MN	56303
Stearns County Commissioners	705 Courthouse Sq	St. Cloud	MN	56303
Sturgeon Lake City Clerk	PO Box 98	Sturgeon Lake	MN	55783
Sturgeon Lake Township	86290 New Hall Rd	Sturgeon Lake	MN	55783
Swanville City Clerk	PO Box 296	Swanville	MN	56382
Taconite City Clerk	PO Box 137	Taconite	MN	55786
Thomson Township Clerk	PO Box 92	Esko	MN	55733
Todd County Administrator	215 First Ave S, Ste. 300	Long Prairie	MN	56347
Todd County Commissioners	215 First Ave S, Ste. 300	Long Prairie	MN	56347
Tower City Clerk	PO Box 576	Tower	MN	55790
Town Of White Clerk	PO Box 146	Aurora	MN	55705
Township Clerk	PO Box 34	Walker	MN	56484
Trommald City Clerk	18105 Whitetail St	Trommald	MN	56441
Two Harbors City Administrator	522 First Ave	Two Harbors	MN	55616

LIST OF COUNTIES AND CITIES

Upsala City Clerk	PO Box 159	Upsala	MN	56384
Verndale City Clerk	PO Box 156	Verndale	MN	56481
Wadena City Clerk	PO Box 30	Wadena	MN	56482
Wadena County Administrator	415 Jefferson St S	Wadena	MN	56482
Wadena County Commissioners	415 Jefferson St S	Wadena	MN	56482
Walker City Administrator	PO Box 207	Walker	MN	56484
Willow River City Clerk	PO Box 125	Willow River	MN	55795
Ward Township Clerk	26997 County 18	Browerville	MN	56438
Willow River City Clerk	PO Box 125	Willow River	MN	55795
Windemere Township Clerk	91546 Military Rd	Sturgeon Lake	MN	55783
Winton City Clerk	102 N. Main St	Winton	MN	55796
Wrenshall City Clerk	PO Box 157	Wrenshall	MN	55797
Zemple City Clerk	PO Box 335	Zemple	MN	56636

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota
Docket No. E015/GR-26-199 Completeness Checklist

Source	Information Required	Location
	Minnesota Statutes and Rules	
7825.3200	**Notice of Change in Rates**	
	A utility filing for a change in rates shall serve notice to the commission at least 90 days prior to the proposed effective date of the modified rates. Such notice shall include the items prescribed below for:	Volume 1, Notice of Change in Rates
(A)	A. general rate changes: (1) proposal for change in rates as prescribed in part 7825.3500; (2) modified rates as prescribed in part 7825.3600; (3) expert opinions and supporting exhibits as prescribed in part 7825.3700; (4) informational requirements as prescribed in parts 7825.3800 to 7825.4400; and (5) statement indicating the method of insuring the payment of refunds as prescribed in part 7825.3300;	Volume 1, and see below for reference to parts 7825.3500, 7825.3600, 7825.3700, 7825.3800-4400, and 7825.3300
7825.3300	**Methods and Procedures for Refunding**	
	An unqualified agreement, signed by an authorized official of the utility, to refund to the customers or credit to customers' accounts within 90 days from the effective date of the commission order any portion of the increase in rates determined to be unreasonable together with interest at the average prime interest rate computed from the effective date of the proposed rates through the date of refund or credit.	Volume 1, Notice of Change in Rates, Section F and Agreement and Undertaking
7825.3500	**Proposal for Change in Rates**	
	The Utility's proposal for a change in rates shall summarize the notice of change in rates and shall include the following information:	Volume 1, Notice of Change in Rates
(A)	name, address, and telephone number of the utility without abbreviation and the name and address and telephone number of the attorney for the utility, if there be one;	Volume 1, Notice of Change in Rates, Section B.1 and B.2
(B)	date of filing and date modified rates are effective;	Volume 1, Notice of Change in Rates, Section B.3
(C)	description and purpose of the change in rates requested;	Volume 1, Notice of Change in Rates, Section B.4
(D)	effect of the change in rates expressed in gross revenue dollars and as a percentage of test year gross revenue; and	Volume 1, Notice of Change in Rates, Section B.5
(E)	signature and title of utility officer authorizing the proposal.	Volume 1, Notice of Change in Rates, Section B.6

Source	Information Required	Location
7825.3600	**Modified Rates**	
	All proposed changes in rates shall be shown by filing revised or new pages to the rate book previously filed with the commission and by identifying those pages which were not changed. In addition, each revised page shall contain the revision number and the page number of the revised page.	Volume 3, Direct Schedules J-1- Summary of Rate Sheets Not Changed or Cancelled, J-2- Clean General Tariff Sheets, J-3-Redlined General Tariff Sheets[1]
7825.3700	**Expert Opinions and Supporting Exhibits**	
	Expert opinions and supporting exhibits shall include written statements, in question and answer format, together with supporting exhibits of utility personnel and other expert witnesses as deemed appropriate by the utility in support of the proposal. At a minimum, expert opinions shall include a statement by the chief executive officer or other designated official in support of the proposal.	Volume 2, Direct Testimony and Schedules of: Jennifer J. Cady, Joshua D. Taran, Ann E. Bulkley, Arik C. Forsman, Joshua G. Rostollan, Michelle A. Bleicher, Diana C. McFadden, Todd Z. Simmons, Daniel W. Gunderson, Joshua P. Goutermont, Wing H. Chan, Tara L. Anderson, Michael F. Farrell, Rena E. Verdoljak, Levi A. Peterson, Amanda L. Turner, and Leah N. Peterson. Volume 1, Notice of Change in Rates, Section D
7825.3900	**Jurisdictional Financial Summary Schedule**	
	A jurisdictional financial summary schedule as required by part 7825.3800 shall be filed showing:	
(A)	the proposed rate base, operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the test year;	Volume 3, Direct Schedule A-1
(B)	the actual unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year; and	Volume 3, Direct Schedule A-1
(C)	the projected unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income under present rates, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.	Volume 3, Direct Schedule A-1

[1] References to the Company's schedules supporting interim rates are included later in this checklist, in conjunction with Minn. Stat. § 216B.16, subd. 3 and the Commission's Policy on Interim Rates.

Source	Information Required	Location
7825.4000	**Rate Base Schedules**	
	The following rate base schedules as required by part 7825.3800 shall be filed:	
(A)	A rate base summary schedule by major rate base component (e.g. plant in service, construction work in progress, and plant held for future use) showing the proposed rate base, the unadjusted average rate base for the most recent fiscal year and unadjusted average rate base for the projected fiscal year. The totals for this schedule shall agree with the rate base amounts included in the financial summary.	Volume 3, Direct Schedules B-1 through B-4
(B)	A comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component showing:	
(1)	total utility and the proposed jurisdictional rate base amounts for the test year including the adjustments, if any, used in determining the proposed rate base;	Volume 3, Direct Schedule B-3
(2)	the unadjusted average total utility and jurisdictional rate base amounts for the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule B-4
(C)	Adjustment schedules, if any, showing the title, purpose, and description and the summary calculations of each adjustment used in determining the proposed jurisdictional rate base.	Volume 3, Direct Schedules B-5 and B-6 Volume 2, Turner Direct at Section V.A Volume 4, Workpapers ADJ-RB-1 through ADJ-RB-16
(D)	A summary by rate base component of the assumptions made and the approaches used in determining average unadjusted rate base for the projected fiscal year. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Volume 3, Direct Schedules B-7 through B-15 Volume 4, Workpapers RB-1 through RB-12
(E)	For multijurisdictional utilities only, a summary by rate base component of the jurisdictional allocation factors used in allocating the total utility rate base amounts to the Minnesota jurisdiction. This summary shall be supported by a schedule showing for each allocation factor the total utility and jurisdictional statistics used in determining the proposed rate base and the Minnesota jurisdictional rate base for the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule B-16 through B-19 Volume 2, Levi Peterson Direct at Schedule 1 and Schedule 2
7825.4100	**Operating Income Schedules**	
	The following operating income schedules as required by part 7825.3800 shall be filed:	
(A)	A summary schedule of jurisdictional operating income statements which reflect proposed test year operating income, and unadjusted jurisdictional operating income for the most recent fiscal year and the projected fiscal year calculated using present rates.	Volume 3, Direct Schedules C-1 and C-2

Source	Information Required	Location
(B)	For multijurisdictional utilities only, a schedule showing the comparison of total utility and unadjusted jurisdictional operating income statement for the test year, for the most recent fiscal year and the projected fiscal year. In addition, the schedule shall provide the proposed adjustments, if any, to jurisdictional operating income for the test year together with the proposed operating income statement.	Volume 3, Direct Schedules C-3 and C-4
(C)	For investor-owned utilities only, a summary schedule showing the computation of total utility and allocated Minnesota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the project fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.	Volume 3, Direct Schedules C-5 through C-8
(D)	A summary schedule of adjustments, if any, to jurisdictional test year operating income and detailed schedules for each adjustment providing an adjustment title, purpose and description of the adjustment, and summary calculations.	Volume 3, Direct Schedules C-9 through C-12 Volume 2, Turner Direct at Section V.B Volume 4, Workpapers, ADJ-IS-1 through ADJ- IS-31
(E)	A schedule summarizing the assumptions made and the approaches used in projecting each major element of operating income. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Volume 3, Direct Schedule C-12 Volume 4, Workpapers, IS-1 through IS-12
(F)	For multijurisdictional utilities only, a schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to Minnesota jurisdiction. This schedule shall be supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.	Volume 3, Direct Schedules C-13 through C-16 Volume 4, Workpapers, AF-1 through AF-6
7825.4200	**Rate of Return Cost of Capital Schedules**	
	The following rate of return cost of capital schedules as required by part 7825.3800 shall be filed:	
(A)	a rate of return cost of capital summary schedule showing the calculation of the weighted cost of capital using the proposed capital structure and the average capital structures for the most recent fiscal year and the projected fiscal year. This information shall be provided for the unconsolidated parent and subsidiary corporations, or for the consolidated parent corporation.	Volume 3, Direct Schedule D-1 Volume 4, Workpapers, COC-1
(B)	supporting schedules showing the calculation of the embedded cost of long-term debt, if any, and the embedded cost of preferred stock, if any, at the end of the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule D-2
(C)	schedule showing average short-term securities for the proposed test year, most recent fiscal year, and the projected fiscal year.	Volume 2, Taran Direct at Section I Volume 3, Direct Schedule D-3

Source	Information Required	Location
7825.4300	**Rate Structure and Design Information**	
	The following rate structure and design information as required by part 7825.3800 shall be filed:	
(A)	A summary comparison of test year operating revenue under present and proposed rates by customer class of service showing the difference in revenue and the percentage change.	Volume 3, Direct Schedules E-1 and E-2 Volume 4, Workpapers IR-1
(B)	A detailed comparison of test year operating revenue under present and proposed rates by type of charge including minimum, demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service.	Volume 3, Direct Schedules E-1 and E-2 Volume 4, Workpapers, IR-2
(C)	A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations. Such study is appropriate whenever the utility proposed a change in rates which results in a material change in its rate structure.	Volume 3, Direct Schedule E-3 Volume 4, Workpapers, COS-1 through COS-4
7825.4400	**Other Supplemental Information**	
	The following supplemental information as required by part 7825.3800 shall be filed:	
(A)	Annual report to stockholders or members including financial statement and statistical supplements for the most recent fiscal year. If a utility is not audited by an independent public accountant, unaudited financial statements will satisfy this filing requirement.	Volume 3, Direct Schedule F-1
(B)	For investor-owned utilities only, a schedule showing the development of the gross revenue conversion factor.	Volume 3, Direct Schedule F-2
(C)	For cooperatives only, REA Form 7, Financial and Statistical Report for the last month of the most recent fiscal year.	N/A
(D)	For cooperatives only, REA Form 7A, Annual Supplement to Financial and Statistical Report.	N/A
(E)	For REA cooperatives only, REA Form 325, Financial Forecast.	N/A
7829.2400	**Filing requiring determination of gross revenue.**	
Subpart 1	Summary. A utility filing a general rate case or other filing that requires determination of its gross revenue requirement shall include, on a separate page, a brief summary of the filing, sufficient to apprise potentially interested parties of its nature and general content.	Volume 1, Summary of Filing

Source	Information Required	Location
Subpart 2	Service. A utility filing a general rate change request shall serve copies of the filing on the department and the Office of the Attorney General. The utility shall serve the filing or the summary described in Subpart 1 on the persons on the applicable general service list and persons who were parties to its last general rate case or incentive plan proceeding.	Volume 1, Notice of Change in Rates Section I.2, Certificate of Service, and Service List
Subpart 3	Notice to public and governing bodies. A utility seeking a general rate change shall give notice of the proposed change to the governing body of each municipality and county in its service area and to its ratepayers. The utility shall also publish notice of the proposed change in newspapers of general circulation in all county seats in its service area.	Volume 1, Notice of Change in Rates, Sections G and H; Proposed Notice to Customers; Proposed Notice to Counties and Municipalities; Proposed Newspaper Publication
Subpart 7	Notice of hearing. The utility shall notify its ratepayers of hearings held in connection with its rate change request in the manner directed by the commission. The utility shall publish notice of hearings on its rate change request in newspapers of general circulation in all county seats in its service area, as directed by the commission.	Volume 1, Notice of Change in Rates Section I.4 and Proposed Newspaper Publication
Minn. Stat. § 216B.16		
Subd. 1	Unless the commission otherwise orders, no public utility shall change a rate which has been duly established under this chapter, except upon 60 days' notice to the commission. The notice shall include statements of facts, expert opinions, substantiating documents, and exhibits, supporting the change requested, and state the change proposed to be made in the rates then in force and the time when the modified rates will go into effect.	Volume 1, Notice of Change in Rates
	If the filing utility does not have an approved energy conservation improvement plan on file with the department, it shall also include in its notice an energy conservation plan pursuant to section 216B.241. A filing utility subject to rate regulation under section 216B.026 shall reference in its notice the energy conservation improvement plans of the generation and transmission cooperative providing energy conservation improvement programs to members of the filing utility pursuant to section 216B.241.	*In the Matter of Minnesota Power's 2024-2026 Energy Conservation and Optimization Triennial Program Modification Request*, Docket No. E015/CIP-23-93, DECISION (Feb. 4, 2026). *In re Minnesota Power's 2027–2029 Triennial Energy Conservation and Optimization Program Filing*, Docket No. E015/CIP-26-91, 2027–2029 Energy Conservation and Optimization Plan (June 15, 2026).
	The filing utility shall give written notice, as approved by the commission, of the proposed change to the governing body of each municipality and county in the area affected.	Volume 1, Notice of Change in Rates, Section G and Proposed Notice to Counties and Municipalities

Source	Information Required	Location
	All proposed changes shall be shown by filing new schedules or shall be plainly indicated upon schedules on file and in force at the time.	Volume 3, Direct Schedules J-1 through J-3
Subd 3(b)	Interim rate. (b) Unless the commission finds that exigent circumstances exist, the interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include: (1) a rate of return on common equity for the utility equal to that authorized by the commission in the utility's most recent rate proceeding; (2) rate base or expense items the same in nature and kind as those allowed by a currently effective order of the commission in the utility's most recent rate proceeding; and (3) no change in the existing rate design. In the case of a utility which has not been subject to a prior commission determination, the commission shall base the interim rate schedule on its most recent determination concerning a similar utility.	Volume 1, Notice and Petition for Interim Rates, Section B.3 and Direct Schedule B-3 (IR) B-7 (IR), B-9 (IR), B-10 (IR), and C-6 (IR).
Subd. 8	Advertising expense. (a) The commission shall disapprove the portion of any rate which makes an allowance directly or indirectly for expenses incurred by a public utility to provide a public advertisement which: (1) is designed to influence or has the effect of influencing public attitudes toward legislation or proposed legislation, or toward a rule, proposed rule, authorization or proposed authorization of the Public Utilities Commission or other agency of government responsible for regulating a public utility; (2) is designed to justify or otherwise support or defend a rate, proposed rate, practice or proposed practice of a public utility; (3) is designed primarily to promote consumption of the services of the utility; (4) is designed primarily to promote good will for the public utility or improve the utility's public image; or (5) is designed to promote the use of nuclear power or to promote a nuclear waste storage facility. (b) The commission may approve a rate which makes an allowance for expenses incurred by a public utility to disseminate information which: (1) is designed to encourage conservation of energy supplies; (2) is designed to promote safety; or (3) is designed to inform and educate customers as to financial services made available to them by the public utility. (c) The commission shall not withhold approval of a rate because it makes an allowance for expenses incurred by the utility to disseminate information about corporate affairs to its owners.	Volume 2, Turner Direct at Section V.B.1 Volume 3, Direct Schedule G-1, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-1
Subd. 9	Charitable contribution. The commission shall allow as operating expenses only those charitable contributions that the commission deems prudent and that qualify under section 300.66, subdivision 3. Only 50 percent of the qualified contributions are allowed as operating expenses.	Volume 2, Turner Direct at Section V.B.2 Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
Subd. 13	Economic and community development and employment of local workers. The commission may allow a public utility to recover from ratepayers the reasonable expenses incurred: (1) for economic and community development; and (2) to employ local workers, as defined in section 216B.2422, subdivision 1, to construct and maintain generation facilities that supply power to the public utility's customers.	Volume 2, Forsman Direct at III.E; Turner Direct at Section V.B.3 Volume 3, Direct Schedule G-5 Volume 4, Workpapers, ADJ-IS-3

Source	Information Required	Location
Subd. 17	(a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: (1) travel and lodging expenses; (2) food and beverage expenses; (3) recreational and entertainment expenses; (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (6) dues and expenses for memberships in organizations or clubs; (7) gift expenses; (8) expenses related to owned, leased, or chartered aircraft; and (9) lobbying expenses.	Volume 2, Bleicher Direct at Section III and Direct Schedules 8 and 9 Volume 3, Direct Schedules H-1 to H-11
	(b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized, separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one- page summary of the total amounts for each expense category included in the petitioning utility's proposed test year.	Volume 2, Bleicher Direct at Section III and Direct Schedules 8 and 9 Volume 3, Direct Schedules H-1 to H-11
	(c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.	Volume 1, Statement Regarding Trade Secret Information Volume 3, Direct Schedule H-5A
Commission Policy Statements		
Policy Statement		
Advertising	Statement that recovery is requested only for permitted advertisements.	Volume 2, Turner Direct at Section V.B.1

Source	Information Required	Location
	Description of advertisements for which recovery is requested.	Volume 2, Turner Direct at Section V.B.1 Volume 3, Direct Schedule G-1, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-1
	Sample advertisements for which recovery is requested, including a schedule that: 1. Identifies the sample ad. 2. Categorizes the advertisements by allowable and disallowable type. 3. Defines the percentage by which the content fits into the allowable and disallowable statutory categories. 4. Provides the corresponding test year dollar amount for each ad. 5. Describes the period of time during which each ad will be used, the service area in which it will appear, and the media employed.	Volume 3, Direct Schedule G-1 Volume 4, Workpapers, ADJ-IS-1
Charitable Contributions	Evidence as to whether the recipients of the contributions: serve the utility's Minnesota service area; are nondiscriminatory in selecting recipients; and do not promote political or special interest groups.	Volume 2, Turner Direct at Section V.B.2 Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
	Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual.	Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
	Itemized schedule showing amount, recipient and time of donations.	Volume 3, Direct Schedule G-2 Volume 4, Workpapers, ADJ-IS-2
Organizational Dues	Schedule showing each organization being paid, the number of employees belonging to each organization and the dollar amount of dues being paid to each organization.	Volume 2, Bleicher Direct at Section III.C Volume 3, Direct Schedule G-3 and Direct Schedule H-6 Volume 4, Workpapers, ADJ-IS-4
	Testimony explaining whether the primary purpose of each organization is educating utility employees about providing improved utility service, training employees to become better qualified to provide improved utility service, or membership is a necessary qualification for employees to carry on their responsibilities or provides essential information to the utility.	Volume 2, Bleicher Direct at Section III.C and Direct Schedule 10; Turner Direct at Section V.B.4 Volume 3, Direct Schedule G-3 and Direct Schedule H-6 Volume 4, Workpapers, ADJ-IS-4

Source	Information Required	Location
Research Expenses	A schedule which describes each research activity for which an expense is claimed and itemizes and supports all expense for each activity.	Volume 2, Bleicher Direct at Section IV Volume 3, Direct Schedule G-4
	Testimony that explains the nature of control of the research, identifies who will conduct the research, describes who will benefit from the research and the time needed for those benefits to accrue, and who will acquire property rights to the products that result from the research.	Volume 2, Bleicher Direct at Section IV Volume 3, Direct Schedule G-4
Cash Working Capital	Lead/lag study with: 1) lead time divided into service to meter reading; meter reading to billing; and billing to collection; and 2) lag expenses divided into categories such as fuel, purchased power, labor, etc.	Volume 2, Turner Direct at Section III.B Volume 4, Workpapers, OS-2
	Other issues may include average minimum cash balances required, depreciation, dividends and interest on debt.	Volume 2, Turner Direct at Section III.B Volume 3, Direct Schedule B-15 Volume 4, Workpapers OS-2, ADJ-RB-3, ADJ- RB-15
Interim Rates	http://mn.gov/puc-stat/documents/pdf_files/012031.pdf	
Page 2(1)	Name, address, and telephone number of utility without abbreviation and the name, address, and telephone number of the attorney for the utility, or other representative upon whom official service may be made.	Volume 1, Notice and Petition for Interim Rates, Section B.1
Page 2(2)	Date of filing and date proposed interim rates are requested to become effective.	Volume 1, Notice and Petition for Interim Rates, Section B.2
Page 2(3)	Description and need for interim rates.	Volume 1, Notice and Petition for Interim Rates, Sections A and B.3
Page 2(4)	Description and corresponding dollar amount changes included in interim rates as compared with most current approved general rate case and with the most recent actual year for which audited data is available. The data for the most recent actual year should be for the same time period in months as the test year, if the test year is a projected test year.	Volume 1, Notice and Petition for Interim Rates, Section B.4 and Direct Schedules C-1 (IR) through C-8 (IR) and D-1 (IR) through D-7 (IR)
Page 2(5)	Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues.	Volume 1, Notice and Petition for Interim Rates, Section B.5 and Direct Schedule C-5 (IR)
Page 2(6)	Certification by officer of the utility that affirms the proposed interim rate petition is in compliance with Minnesota Statutes.	Volume 1, Notice and Petition for Interim Rates, Section B.6 and Certification

Source	Information Required	Location
Page 2(7)[2] [1]	Signature and title of the utility officer authorizing the proposed interim rates.	Volume 1, Notice and Petition for Interim Rates, Section B.8
Page 3(1)	A schedule showing the interim rate of return calculation. This schedule should show the capital structure and rate of return calculation approved by the Commission in the most recent general rate case; the capital structure and rate of return calculation proposed for interim rates; and a description and corresponding dollar amount of any changes between the two capital structures.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Direct Schedules C-6 (IR), C-7 (IR), D-6 (IR), and D-7 (IR)
Page 3(2)	A schedule showing the interim operating income statement. This schedule should show the same operating income statement accounts as filed in the general rate case. Also, the schedule should include the operating income statement approved by the Commission in the most recent general rate case; the equivalent operating income statement corresponding with the most recent actual year for which audited data is available and corresponding with the same period in months as the test year, if the test year is a projected test year; and the operating income statement proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the operating income statements should be provided. Work papers should be provided which show how revenues, AFUDC, taxes, expenses, and other income statement components have been determined.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules Volume 4, Workpapers, RB-1 through RB-12 and IS-1 through IS-12
Page 3(3)	A schedule showing the interim proposed rate base. This schedule should include the average rate base approved by the Commission in the most recent general rate case; the equivalent average rate base corresponding with the most recent actual year for which audited data is available and corresponding with the same period in months as the test year, if the test year is a projected test year; and the average rate base proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the rate bases should be provided. Workpapers should be provided which show how the rate base components have been determined.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules Volume 4, Workpapers, IR-1 and IR-2
Page 3(4)[3]	A schedule showing revenue deficiency calculations for each of the operating income statements and rate bases requested in (2) and (3) above. The revenue deficiency should be calculated for the actual data and the interim data using the rate of return calculated in (1) above.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules
	Modified Tariffs	Volume 1, Notice and Petition for Interim Rates, Section B.10 Volume 1, Interim Tariff Sheets – Redlined; Interim Tariff Sheets – Clean

[2] Item 7 actually appears on Page 3 of the Statement of Policy.
[3] Item 4 actually appears on Page 4 of the Statement of Policy.

Source	Information Required	Location
	Notices	Volume 1, Notice and Petition for Interim Rates, Section B.11and Proposed Notice to Counties and Municipalities; Proposed Notice to Customers
	All Utility Dockets	
E999/AA-09-961 **E999/AA-10-884**	**In the Matter of the Review of the 2008-2009 Annual Automatic Adjustment Reports for All Electric Utilities** **In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities**	
ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS (Apr. 6, 2012)	11. The Commission will require the utilities to continue to show benefits of the MISO Day 1 in their rate cases before receiving cost recovery of MISO Schedule 10 costs.	Volume 2, Forsman Direct at Section IV.C.2
E,G999/CI-20-492	**In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic**	
ORDER ACCEPTING ECONOMIC-RECOVERY INVESTMENT REPORTS, REQUIRING FILINGS, AND ENCOURAGING ADVANCEMENT OF DIVERSITY GOALS	2. Utilities shall track investments separately from base rates to ensure transparency of the recovery process.	The Commission approved Minnesota Power's proposal to build three new solar arrays at Laskin, Duluth, and Sylvan to support economic relief and recovery from the COVID-19 pandemic in Docket Nos. E015/M-20-828 and E,G999/CI-20-492. These projects are currently in-service. Reporting requirements were discontinued by the Commission's January 28, 2025 Order in this docket.
E,G999/CI-22-624	**In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act**	
ORDER SETTING REQUIREMENTS RELATED TO INFLATION REDUCTION ACT (Sept. 12, 2023)	1. The utilities shall maximize the benefits of the Inflation Reduction Act in future resource acquisitions and requests for proposals in the planning phase, petitions for cost recovery through riders and rate cases, resource plans, gas resource plans, integrated distribution plans, and Natural Gas Innovation Act innovation plans. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures. Reporting shall continue until 2032.	Volume 2, Verdoljak Direct at Section V.A; Cady Direct at Section III.A.

Source	Information Required	Location
	2. As utilities address how they have captured and maximized benefits from the Inflation Reduction Act to ensure customer rates remain reasonable in future filings until 2032, they shall also include an assessment of internal resources or costs needed to capture those benefits.	Volume 2, Verdoljak Direct at Section V; Cady Direct at Section III.A.
E,G999/M-19-505 **E,G999/CI-12-1344**	**In the Matter of a Petition by the Citizens Utility Board of Minnesota to Adopt Open Data Access Standards** **In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities**	
ORDER REFINING OPEN DATA ACCESS STANDARDS (Jul. 5, 2024)	4. Utilities must reflect costs and revenues associated with responding to data requests for anonymized CEUD [Customer Energy Use Data] in rate cases.	Volume 2, Turner Direct at Section VI.F.
	Minnesota Power Dockets	
E015/AI-08-339 **E015/AI-08-340** **E015/AI-08-341**	**In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement between ALLETE, Inc. and its Subsidiary, ALLETE Properties, LLC (f/k/a MP Real Estate Holdings, Inc.)** **In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement Between ALLETE, Inc. and its Subsidiary, Superior Water, Light and Power (SWL&P)** **In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement Between ALLETE, Inc. and its Subsidiary, Minnesota Power Enterprises, Inc. (MP Enterprises)**	
ORDER (Jan. 13, 2009)	The Company must demonstrate in future rate cases that the First Amendment to the Services Agreement has not resulted in cross-subsidization by Minnesota Power's ratepayers of the activities of its affiliated companies.	Volume 2, Bleicher Direct at Section II.B
E015/PA-08-928	**In the Matter of a Petition for Approval of a Redevelopment Agreement for the M.L. Hibbard Units 3 & 4 Boilers and Related Facilities from the City of Duluth and for Approval of Investments and Expenditures at the M.L. Hibbard Energy Center Through Minnesota Power's Renewable Energy Rider under Minn. Stat. § 216B.1645**	
ORDER APPROVING PURCHASE AND MAKING FINDINGS RELEVANT TO RECOVERY OF UPGRADE EXPENDITURES THROUGH THE RENEWABLE ENERGY RIDER (Sept. 22, 2009)	4.a. MP shall address, in the first rate case after Hibbard goes into service and in all subsequent rate cases until the Commission orders otherwise, whether the Hibbard facility is used and useful in providing retail utility service and whether the investments and related expenses and revenues are reasonable and prudently incurred.	Volume 2, Simmons Direct at Section IV.C
E015/GR-09-1151	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Nov. 2, 2010)	17. The Company shall account for future lobbying expenses by assigning both employee and contract lobbying expenses to FERC Account 426.4 and excluding this category from operating and maintenance expenses recovered from ratepayers.	Volume 2, Bleicher Direct at Section III.E; Turner Direct at Sections V.B.4 and V.B.5 Volume 3, Direct Schedules H-1, H-8, and H-11

Source	Information Required	Location
	19. In future rate case filings, the Company shall provide all data used in its test year sales forecasts at least 30 days before filing the rate case.	October 1, 2026 filing in Docket No. E015/GR-26-199 eDocket Document ID 202610-237030-01, 202610-237030-02 (TS), and 202610-237030-03 (TS) (TS)
	20. In future rate case filings, the Company shall conduct any Class Cost of Service Study (CCOSS) by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.	Volume 2, Levi Peterson Direct at Section II and Schedule 1
E015/GR-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Mar. 12, 2018)	47. In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery.	Volume 2, Levi Peterson Direct at Section VI
E015-AI-17-568	**In the Matter of Minnesota Power's Petition for Approval of *EnergyForward* Resource Package**	
ORDER APPROVING AFFILIATED-INTEREST AGREEMENTS WITH CONDITIONS (Jan.. 24, 2019)	4. In any future rate case in which Minnesota Power seeks to recover costs associated with the NTEC purchase, the Company will be required to prove the propriety of the costs associated with this deal structure in contrast to other cost structures that the Company chose not to use, which would include a PPA-like levelized payment structure.	Not applicable; Minnesota Power is not seeking recovery of costs associated with the NTEC purchase in this rate case filing.
E-015/M-21-257	**In the Matter of Minnesota Power's Electric Vehicle Charging Infrastructure Investment**	
ORDER APPROVING PROPOSAL AS MODIFIED, AUTHORIZING DEFERRED ACCOUNTING, AND REQUIRING REPORTING (Oct. 22, 2021)	9. The Commission approves Minnesota Power's request for deferred accounting, but places the following limitations on the deferred accounting authorization:	
	a. Only capital costs and depreciation costs related to the actual EV capital investment may be accrued in the deferred account.	Volume 2, Goutermont Direct at Section II.C. 3; Turner Direct at Section V.A.8 Volume 4, Workpapers, ADJ-RB-8 and ADJ-IS- 12
	b. Only the project revenue requirements, including operation and maintenance costs, that are clearly incremental to those approved in the company's rate case proceeding in Docket Nos. E015/GR-19-442 and E015/M-20-429 (and not Minnesota Power labor expenses already built into base rates) will be considered eligible to be reviewed for eventual recovery.	Volume 2, Goutermont Direct at Section II.C. 3; Turner Direct at Section V.A.8 Volume 4, Workpapers, ADJ-RB-8 and ADJ-IS- 12

Source	Information Required	Location
	c. Minnesota Power may not accrue in the deferred account a return on its capital expenditures associated with the proposal.	Volume 2, Goutermont Direct at Section II.C. 3; Turner Direct at Section V.A.8 Volume 4, Workpapers, ADJ-RB-8 and ADJ-IS- 12
	d. Minnesota Power may not accrue in the deferred account property taxes related to the proposal unless the Company can show that actual total property taxes are higher than total property taxes built into base rates.	Volume 2, Turner Direct at Section V.A.8 Volume 4, Workpapers, ADJ-RB-8 and ADJ-IS- 12
ORDER (Sept. 12, 2023)	Approved MP's request to extend deferred accounting for its EV charging investments until the beginning of the test year in MP's next rate case following the rate case expected in November 2023.	Volume 2, Goutermont Direct at Section II.C. 3; Turner Direct at Section V.A.8 Volume 4, Workpapers, ADJ-RB-8 and ADJ-IS- 12
E015/GR-21-335	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Feb. 28, 2023)	Page 63. The Commission also concurs with the Administrative Law Judge, the Department, and LPI that after the Company fully deploys its advanced metering technology, Minnesota Power should develop future E8760 allocators using updated data.	Volume 2, Levi Peterson Direct at Section III.A and Schedule 1; Volume 4, Workpapers, AF
	8. Minnesota Power must establish a sunset provision ending December 31, 2026, for the Company's recovery of Taconite Harbor Energy Center's remaining depreciation expense.	Volume 2, Turner Direct at Section VI.F
	9. Minnesota Power must establish a sunset provision for Taconite Harbor Energy Center Operations and Maintenance (O&M) expenses, such that the Company will cease collecting these O&M expenses once it begins decommissioning the facility.	Volume 2, Turner Direct at Section VI.F
E015/M-23-258	**In the Matter of Minnesota Power's 2023 Integrated Distribution Plan**	
ORDER APPROVING PILOT PROGRAM WITH MODIFICATIONS (Jul. 29, 2025)	11. Minnesota Power is authorized to use deferred accounting to track and request future recovery of Operations and Maintenance (O&M) pilot costs.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
	12. Minnesota Power is not allowed to earn a rate of return on the deferred O&M costs.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14

Source	Information Required	Location
	13. Minnesota Power is authorized to treat utility-owned service connection capital additions and depreciation expenses as distribution plant expenditures and recover them in a future general rate case via deferred accounting.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
	14. Minnesota Power is not allowed to record a rate of return on the deferred capital expenditures.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
	15. Deferred accounting treatment and potential recovery are limited to only the costs incremental to Minnesota Power's most recent rate case.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
	16. Deferred accounting treatment is limited to only the costs incurred before the start of the next rate case test year.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
	17. Minnesota Power's recovery of MDU pilot costs is limited to the budget approved by the Commission, subject to future prudence review, unless Minnesota Power shows by clear and convincing evidence that any costs incurred above that amount were reasonable, prudent, and beyond the Company's control.	Volume 2, Forsman Direct at III.C; Turner Direct at V.A.9 and V.B.14 Volume 4 Workpapers, ADJ-RB-9 and ADJ-IS-14
E015/D-24-324; E-015/M-24-437; E015/D-25-342	**In the Matter of Minnesota Power's 2024 Remaining Life Depreciation Petition; In the Matter of Minnesota Power's Petition for Approval to Track and Defer Costs Resulting from the Legacy Coal Combustion Rule Surface Impoundment Rule; In the Matter of Minnesota Power's 2025 Remaining Life Depreciation Petition.**	
ORDER (Oct. 29, 2025)	2. Approved the continued use of a 2035 estimated remaining life of Boswell Energy Center (BEC) 3, BEC 4, and BEC Common for depreciation purposes and required that any depreciation adjustments required for these facilities would be implemented in Minnesota Power's next rate case or other appropriate proceeding. (See also ORDER (Jan. 27, 2026) in Docket No. E015/D-25-342)	Volume 2, Simmons Direct at Section V; Turner Direct at Section VI.E
E015/M-19-766	**In the Matter of Minnesota Power's Reconnect Pilot Program**	
ORDER (Jul. 1, 2026)	4. Required Minnesota Power to provide, in its next general rate case, testimony delineating the cost of remote reconnections, the cost of on-site reconnections, and a discussion of any potential cost shift.	Volume 2, Goutermont Direct at Section III.B.

Source	Information Required	Location
E015/GR-23-155	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
ORDER ACCEPTING AND ADOPTING AGREEMENT SETTING RATES, (Nov. 25, 2024)	1. The Commission accepts and approves the Settlement concerning the Application of Minnesota Power for the Authority to increase rates for electric service in the State of Minnesota pursuant to Minn Stat. § 216B.16, subd. 1. Settlement Agreement at 13. The Settling Parties further agree that Minnesota Power, as part of its next general rate case, shall propose a revenue apportionment that moves each customer class closer to its cost of service as shown on a CCOSS developed by Minnesota Power in that case. Minnesota Power's proposal of such a revenue apportionment is not binding on any party, and the proposal shall not carry any presumption of reasonableness. All parties reserve the right to respond to or oppose that proposal in any manner they choose based on the record and their analyses in that future proceeding.	Volume 2, Leah Peterson Direct at Section II.C.
E015/PA-24-198	**In the Matter of the Petition of Minnesota Power for Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners**	
ORDER APPROVING PETITION FOR ACQUISITION WITH CONDITIONS AND ESTABLISHING OTHER REQUIREMENTS (Dec. 10, 2025); Settlement at ¶ 1.12	If Minnesota Power's cost of debt increases above current levels within five years following the close of the Acquisition, Minnesota ratepayers will be held harmless from any rate impact unless Minnesota Power can demonstrate that its increased cost of debt was not caused by the Acquisition. Beginning five years through ten years following the close of the Acquisition, Minnesota Power shall bear the burden to explain any cost of debt increase. For years five through ten, nothing about this shall change the company's obligation with respect to its overall burden of proof under Minnesota law.	Volume 2, Taran Direct at Section IV.A and IV.B
Settlement at ¶ 1.13	Minnesota Power shall maintain its capital structure within the range approved by the Commission in the annual capital structure filing, and Minnesota Power will continue its efforts to manage its capital structure to the level approved in its most recent Minnesota rate case.	Volume 2, Taran Direct at Section IV.C
Settlement at ¶ 1.14	As a negotiated resolution, and without agreeing to any party's underlying position on this issue, Minnesota Power's currently approved Return on Equity ("ROE") will be changed from 9.78 percent to 9.65 percent.[4] The change in ROE will take effect the first full month after both of the following have occurred: (i) the close of the Acquisition and (ii) when the order of the Commission becomes final. The 9.65 percent ROE will remain in effect until Minnesota Power files its next rate case and will be used to set interim rates in Minnesota Power's next Minnesota rate case. Nothing in this settlement stipulation shall be considered a commitment (i) to any specific ROE in the company's next rate case or (ii) to use a specific methodology to determine the ROE in the company's next rate case.	Notice and Petition for Interim Rates, Section B.3; Volume 2, Turner Direct at Section V.

[4] This includes Minnesota Power's commitment not to seek recovery of flotation costs but extends that commitment to the closing of the Acquisition rather than waiting until implementation with the next rate case.

Source	Information Required	Location
Settlement at ¶ 1.23a	The company's senior management team shall be responsible for the day-to-day operations of Minnesota Power, including but not limited to, developing strategic plans; developing budget proposals; building, operating, and maintaining utility infrastructure; developing and handling regulatory filings and proceedings; and stakeholder engagement.	Volume 2, Rostollan Direct at Section II.A
Settlement at ¶ 1.40	There will be no attempt to recover Acquisition costs, transaction costs, transition costs, or the acquisition premium from utility customers. ALLETE and Minnesota Power shall not defer any transaction or transition costs. In future rate cases, Minnesota Power shall have the burden to establish through testimony and schedules that no such costs are included in historical expenses of the operating utility or in the determination of revenue requirement.	Volume 2, Rostollan Direct at Section II.A; Bleicher Direct at Section III.B.
Settlement at ¶ 1.40 a.	The term "transaction costs" shall mean the costs incurred to structure, negotiate and consummate the transaction, professional services fees, including but not limited to good will, legal fees, regulatory filing costs, investment banker fees, counsel fees, audit fees, and accounting fees, other costs historically recognized as transaction costs, and external services needed to evaluate the merger, negotiate its terms, obtain regulatory approvals, obtain shareholder approvals, and execute transaction contracts.	Volume 2, Rostollan Direct at Section II.A;
Settlement at ¶ 1.40 b.	The term "transition costs" shall mean costs incurred due to the Acquisition other than transaction costs, including but not limited to: severance costs; the costs to combine, integrate, and/or align Minnesota Power, ALLETE, CPP and GIP following the transaction, including, but not limited to accounting and operating systems software integration costs; costs for moving employees (including changing headquarters); re-organization costs; bonuses or other compensation paid out as a result of the transaction; costs to terminate any duplicative leases, contracts, and operations; or financing costs to refinance existing obligations in order to achieve operational and financial synergies.	Volume 2, Rostollan Direct at Section II.A;
Settlement at ¶ 1.41	Minnesota Power will have the burden to prove in its next rate case that no transaction costs, nor other costs expressly committed to in this table for exclusion from future rate cases, are included in the cost of service to be recovered from customers.	Volume 2, Taran Direct at Sections IV.A and IV.B; Bulkley Direct at Section VII.D; Rostollan Direct at Section II.A; Bleicher Direction at Sections II.C and III.B
Settlement at ¶ 1.42	Costs associated with any holding company petition or separation efforts will not be considered transaction or transition costs of the Acquisition and recovery of same shall be considered in any holding company docket.	Volume 2, Cady Direct at Section IV.B
Settlement at ¶ 1.43	Minnesota Power waives its right to file a rate case before November 1, 2026.	Volume 2, Turner Direct at Section VI.B
Settlement at ¶ 1.44	Minnesota Power will include a comparison of its requested rate increase and the annual rate of inflation in any general rate case, rider filing, or any other proceeding that would request an increase to residential customer rates.	Volume 2, Turner Direct at Section VI.4

Source	Information Required	Location
Settlement at ¶ 1.51	As long as the Partners own Minnesota Power, Minnesota Power shall not seek rate recovery of flotation costs.	Volume 2, Bulkley Direct at Section VII.D
Settlement at ¶ 1.52	As long as the Partners own Minnesota Power, Minnesota Power shall not seek rate recovery of Investor Relations costs	Volume 2, Bleicher Direct at Section II.C
Settlement at ¶ 1.53	The Partners will not charge fees for any business management or consulting services provided to ALLETE or Minnesota Power.	Volume 2, Rostollan Direct at Section II.A
Settlement at ¶ 1.54	For as long as Minnesota Power is owned by the Partners, Minnesota Power will not request rate recovery of board compensation or expenses for any board member not independent from the Partners.	Volume 2, Bleicher Direct at Section II.D and Schedule 2 Volume 3, Schedules H-1 and H-4
Settlement at ¶ 1.55	Minnesota Power will have the burden to prove in its next rate case that no transaction costs, nor the costs identified in the Ratemaking section of this Agreement for exclusion from future rate cases, are included in the cost of service to be recovered from customers.	Volume 2, Taran Direct at Sections IV.A and IV.B; Bulkley Direct at Section VII.D; Rostollan Direct at Section II.A; Bleicher Direction at Sections II.C and III.B
Settlement at ¶ 1.63 d, Order Point 6	Neither contributions to the Clean Firm Technology Fund ("Fund") nor the portion of an investment or project financed with the Fund would be subject to cost recovery (e.g., no return on capital or depreciation). ALLETE shall file annual reporting on the Clean Firm Technology Fund referenced in Paragraph 1.63 of the Settlement Stipulation, including sources of funding, total disbursements from the fund by project and FERC Account, and status of projects funded, until all projects financed entirely or partly by the Fund are completed, in service, and, if appropriate, included in rate base used to establish final rates in a Commission approved rate case.	Volume 2, Rostollan Direct at Section II.A
Order Point 8	Minnesota Power's rate of return on equity is capped at 9.78 percent (as approved in Docket No. E-015/GR-23-155) and Minnesota Power's equity ratio in its capital structure will be capped at 53.0 percent until December 31, 2030. This condition does not prohibit Minnesota Power from filing new rate cases or from proposing in rate cases what an ROE would be absent the temporary cap. The Commission may reduce the rate of return on equity by up to 100 basis points if it finds any significant violation of conditions imposed in this docket in addition to all other enforcement authorities granted in the Settlement Stipulation and Addendum and within the statutory authority of the Commission.	Volume 2, Taran Direct at Section IV Volume 2, Bulkley Direct at Sections III and IX
E015/M-25-140	**In the Matter of Minnesota Power's 2025 Integrated Distribution Plan**	
ORDER ACCEPTING 2025 INTEGRATED DISTRIBUTION PLAN (Sept. 1, 2026)	7. Minnesota Power must file a wildfire mitigation plan (WMP) in a new docket by February 1, 2027 for Commission acceptance and review. . . . Minnesota Power must file for recovery of WMP costs within a general rate case to allow for a full prudence review of those investments.	Volume 2, Goutermont Direct at Section III.C

IN THE MATTER OF THE APPLICATION OF MINNESOTA POWER FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN MINNESOTA

MPUC DOCKET NO. E015/GR-26-199

CERTIFICATE OF SERVICE

I, Kodi J. Verhalen, hereby certify that on the 2nd day of November, 2026, on behalf of Minnesota Power, I electronically filed a true and correct copy of **Minnesota Power's Application for Authority to Increase Electric Service Rates in Minnesota** by posting the same on eDockets.

A **Summary of Filing** was provided via electronic service or United States First Class Mail as designated on the attached Official Service List[1] on file with the Minnesota Public Utilities Commission in the above-referenced docket.

/s/ Kodi J. Verhalen
Kodi J. Verhalen

[1] The attached service list includes those individuals on Minnesota Power's General Service List on file with the Commission and on the Service List for Minnesota Power's most recent rate case (Docket No. E015/GR-23-155).

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	GR-26-199
2	Lori	Andresen	info@sosbluewaters.org	Save Our Sky Blue Waters		P.O. Box 3661 Duluth MN, 55803 United States	Electronic Service		No	GR-26-199
3	Justin	Andringa	justin.andringa@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St Paul MN, 55101 United States	Electronic Service		No	GR-26-199
4	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199
5	Victor	Barreiro	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	GR-26-199
6	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	GR-26-199
7	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	GR-26-199
8	Jason	Bonnett	jason.bonnett@state.mn.us		Public Utilities Commission	121 East 7th Place suite 350 St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199
9	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
10	Jon	Brekke	jbrekke@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	GR-26-199
11	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
12	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	GR-26-199
13	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN,	Electronic Service		Yes	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101 United States				
14	Jennifer	Cady	jjcady@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
15	David	Cartella	david.cartella@cliffsnr.com	Cliffs Natural Resources Inc.		200 Public Square Ste 3300 Cleveland OH, 44114-2315 United States	Electronic Service		No	GR-26-199
16	Greg	Chandler	greg.chandler@upm.com	UPM Blandin Paper		115 SW First St Grand Rapids MN, 55744 United States	Paper Service		No	GR-26-199
17	Steve W.	Chriss	stephen.chriss@walmart.com	Wal-Mart		2001 SE 10th St. Bentonville AR, 72716-5530 United States	Electronic Service		No	GR-26-199
18	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 600 St. Paul MN, 55101 United States	Electronic Service		Yes	GR-26-199
19	Hillary	Creurer	hcreurer@allete.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
20	Patrick	Cutshall	pcutshall@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
21	Lisa	Daniels	lisadaniels@windustry.org	Windustry		201 Ridgewood Ave Minneapolis MN, 55403 United States	Electronic Service		No	GR-26-199
22	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	GR-26-199
23	J.	Drake Hamilton	hamilton@fresh-energy.org	Fresh Energy		408 St Peter St Ste 350 Saint Paul MN, 55101 United States	Electronic Service		No	GR-26-199
24	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	GR-26-199
25	Ron	Elwood	relwood@mnlsap.org	Legal Services Advocacy Project		970 Raymond Avenue Suite G-40 Saint Paul MN, 55114 United States	Electronic Service		No	GR-26-199
26	Eden	Faure	eden.faure@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55402 United States				
27	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	GR-26-199
28	Frank	Frederickson	ffrederickson@mnpower.com	Minnesota Power		30 W Superior St. Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
29	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	GR-26-199
30	John	Gasele	jgasele@fryberger.com	Fryberger Buchanan Smith & Frederick PA		700 Lonsdale Building 302 W Superior St Ste 700 Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
31	Barbara	Gervais	toftemn@boreal.org	Town of Tofte		P O Box 2293 7240 Tofte Park Road Tofte MN, 55615 United States	Electronic Service		No	GR-26-199
32	Jerome	Hall	hallj@stlouiscountymn.gov	Saint Louis County Property Mgmt Dept		Duluth Courthouse 100 N 5th Ave W Rm 515 Duluth MN, 55802-1209 United States	Electronic Service		No	GR-26-199
33	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	GR-26-199
34	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	GR-26-199
35	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
36	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	GR-26-199
37	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		Yes	GR-26-199
38	James	Jarvi		Minnesota Ore Operations - U S Steel		P O Box 417 Mountain Iron MN, 55768 United States	Paper Service		No	GR-26-199
39	Kelsey	Johnson	kjohnson@taconite.org	Iron Mining Association of Minnesota		1003 Discovery Drive Chisholm	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55719 United States				
40	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
41	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
42	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
43	Travis	Kolari		Keetac		PO Box 217 Keewatin MN, 55753 United States	Paper Service		No	GR-26-199
44	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
45	Jennifer	Kuklenski	jkuklenski@mnpower.com	Minnesota Power		30 W Superior St, Duluth, MN, 55802 Duluth MN, 54534 United States	Electronic Service		No	GR-26-199
46	Becky	Lammi	cityclerk@ci.aurora.mn.us	City of Aurora		16 W 2nd Ave N PO Box 160 Aurura MN, 55705 United States	Electronic Service		No	GR-26-199
47	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
48	David	Langmo	david.langmo@sappi.com	Sappi North America		P O Box 511 2201 Avenue B Cloquet MN, 55720 United States	Paper Service		No	GR-26-199
49	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
50	Amber	Lee	amber.lee@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
51	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199
52	LeRoger	Lind	llind@yahoo.com	Save Lake Superior Association		P.O. Box 101 Two Harbors MN, 55616 United States	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
53	Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 Saint Paul MN, 55104-3435 United States	Electronic Service		No	GR-26-199
54	Patrick	Loupin	patrickloupin@packagingcorp.com	Boise Cascade Corporation		PO Box 990050 Boise ID, 83799-0050 United States	Electronic Service		No	GR-26-199
55	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
56	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	GR-26-199
57	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
58	Sarah	Manchester	sarah.manchester@sappi.com	Sappi North American		255 State Street Floor 4 Boston MA, 02109-2617 United States	Electronic Service		No	GR-26-199
59	Robert	Manning	robert.manning@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	GR-26-199
60	Ashley	Marcus	ashley.marcus@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199
61	Emily	Marshall	emarshall@lourismarshall.com	Miller O'Brien Jensen, PA		120 S. 6th Street Suite 2400 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
62	Keith	Matzdorf	keith.matzdorf@sappi.com	Sappi Fine Paper North America		PO Box 511 2201 Avenue B Cloquet MN, 55720 United States	Electronic Service		No	GR-26-199
63	Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro		360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg MB, R3C 2P4 Canada	Electronic Service		No	GR-26-199
64	Matthew	McClincy	mmcclincy@usg.com	USG		35 Arch Street Clouqet MN, 55720 United States	Electronic Service		No	GR-26-199
65	Craig	McDonnell	craig.mcdonnell@state.mn.us		Minnesota Pollution Control Agency	520 Lafayette Road St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
66	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	GR-26-199
67	Stephen	Melchionne	stephen.melchionne@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street, Ste. 1400 St. Paul MN, 55101 United States	Electronic Service		No	GR-26-199
68	Kimberly	Middendorf	kimberly.middendorf@state.mn.us		Office of Administrative Hearings	PO Box 64620 600 Robert St N Saint Paul MN, 55164-0620 United States	Electronic Service		No	GR-26-199
69	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
70	James	Mortenson	james.mortenson@state.mn.us		Office of Administrative Hearings	PO BOX 64620 St. Paul MN, 55164-0620 United States	Electronic Service		No	GR-26-199
71	Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Ave W Ste 515 Saint Paul MN, 55101 United States	Electronic Service		No	GR-26-199
72	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
73	Christopher J.	Oppitz		-		PO Box 910 Park Rapids MN, 56470-0910 United States	Paper Service		No	GR-26-199
74	Elanne	Palcich	epalcich@cpinternet.com	Save Our Sky Blue Waters		P.O. Box 3661 Duluth MN, 55803 United States	Electronic Service		No	GR-26-199
75	Cari	Pedersen	cpedersen@duluthmn.gov	City of Duluth		411 W 1st St Rm 403 Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
76	Max	Peters	maxp@cohasset-mn.com	City of Cohasset		305 NW First Ave Cohasset MN, 55721 United States	Electronic Service		No	GR-26-199
77	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
78	Christine	Pham	christine.pham@state.mn.us		Public Utilities Commission	121 7th place E, suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
79	Jeff	Pollock	jcp@jpollockinc.com	J. Pollock Inc.		Suite 335 12655 Olive Boulevard St. Louis MO, 63141 United States	Electronic Service		No	GR-26-199
80	Tolaver	Rapp	tolaver.rapp@cliffsnr.com	Cliffs Natural Resources		200 Public Square Suite 3400 Cleveland OH, 44114-2318 United States	Electronic Service		No	GR-26-199
81	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	GR-26-199
82	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	GR-26-199
83	Ralph	Riberich	rriberich@uss.com	United States Steel Corp		600 Grant St Ste 2028 Pittsburgh PA, 15219 United States	Electronic Service		No	GR-26-199
84	Santi	Romani		United Taconite		PO Box 180 Eveleth MN, 55734 United States	Paper Service		No	GR-26-199
85	Susan	Romans	sromans@allete.com	Minnesota Power		30 West Superior Street Legal Dept Duulth MN, 55802 United States	Electronic Service		No	GR-26-199
86	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	GR-26-199
87	Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC		1742 Patriot Rd Northfield MN, 55057 United States	Electronic Service		No	GR-26-199
88	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix & Associates		7400 Lyndale Avenue South Suite 190 Richfield MN, 55423 United States	Electronic Service		No	GR-26-199
89	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	GR-26-199
90	Brett	Skyles	brett.skyles@co.itasca.mn.us	Itasca County		123 NE Fourth Street Grand Rapids MN, 55744-2600 United States	Electronic Service		No	GR-26-199
91	Richard	Staffon	rcstaffon@msn.com	W. J. McCabe Chapter, Izaak Walton League of America		1405 Lawrence Road Cloquet MN, 55720 United States	Electronic Service		No	GR-26-199

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
92	Robert	Tammen	bobtammen@frontiernet.net			PO Box 398 Soudan MN, 55782 United States	Electronic Service		No	GR-26-199
93	Jim	Tieberg	jtieberg@polymetmining.com	PolyMet Mining, Inc.		PO Box 475 County Highway 666 Hoyt Lakes MN, 55750 United States	Paper Service		No	GR-26-199
94	Anton	Van Der Merwe	anton.vandermerwe@newrangecoppernickel.com	NewRange Copper Nickel		6500 Kensington Drive Hoyt Lakes MN, 55750 United States	Electronic Service		No	GR-26-199
95	Claire	Vatalaro	cvatalaro@allete.com	Allete		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	GR-26-199
96	Kodi	Verhalen	kverhalen@taftlaw.com	Taft Stettinius & Hollister LLP		80 S 8th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	GR-26-199
97	Scott	Zahorik	scott.zahorik@aeoa.org	Arrowhead Economic Opportunity Agency		702 S. 3rd Avenue Virginia MN, 55792 United States	Electronic Service		No	GR-26-199