Direct Testimony and Schedules
Amanda L. Turner

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-23-155

Exhibit ________

REVENUE REQUIREMENTS

November 1, 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Amanda L. Turner, and my business address is 30 West Superior Street, Duluth, Minnesota, 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc. ("ALLETE"), doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Costing and Pricing Analyst Senior.

Q. Please describe your educational background and work experience with Minnesota Power.

A. I have a Bachelor of Science in Mathematics from the College of Saint Scholastica. I have nine years of experience in revenue requirements. I am currently responsible for maintaining Minnesota Power's UIPlanner application, which includes the Company's Class Cost of Service Study ("CCOSS") model, as well as coordinating revenue requirement support for general rate cases, other financial regulatory filings, and projects.

Q. What is the purpose and scope of your testimony?

A. The purpose of my testimony is to support Minnesota Power's revenue requirements for the test year consisting of calendar year 2024. My testimony addresses the determination of rate base and operating income. My testimony also discusses the treatment of adjustments made in the Interim and Proposed Test Year CCOSSs and supports the determination of the Minnesota Jurisdictional revenue increase required by Minnesota Power to earn its requested rate of return in the Proposed Test Year and the allowed rate of return in the Interim Test Year. Additionally, I explain how the Company's cost recovery riders and tracker balances bear on our 2024 test year cost of service, building on the detailed testimony of Company witnesses Mr. Stewart J. Shimmin and Ms. Rena E. Verdoljak. I also support the Company's Conservation

Improvement Program ("CIP") tracker and base rate totals. Finally, I address several compliance items from other dockets.

Q. What schedules are you sponsoring in your testimony?

A. I am sponsoring the following schedules that immediately follow my testimony; they are identified as:

- MP Exhibit ___ (Turner), Direct Schedule 1 – Summary of Proposed Increase to Interim and General Rate Revenues;
- MP Exhibit ___ (Turner), Direct Schedule 2 – Revenue Credits Summary; and
- MP Exhibit ___ (Turner), Direct Schedule 3 – Rate Case Adjustments.

II. SUMMARY OF RATE CHANGE REQUEST

Q. Please summarize Minnesota Power's proposed increase to Interim and General Rate revenues in this proceeding.

A. Minnesota Power proposes an Interim Rate increase net of riders moving to base rates of $63.8 million (8.6 percent) MN Jurisdictional[1] and a General Rate increase of $89.1 million (12.0 percent) MN Jurisdictional. Without factoring the offsetting impact of reduced riders as some costs move to base rates, the Interim Rate increase is $102.6 million (13.8 percent), and the General Rate increase is $127.9 million (17.2 percent).

The General Rate and Interim Rate revenue requirements, revenue deficiency, and proposed rate increase percentage are summarized on MP Exhibit ___ (Turner), Direct Schedule 1 to my testimony. Additionally, Volume 1, Direct Schedule A-1 (IR) and Volume 3, Direct Schedule A-1 summarize Minnesota Power's proposed Interim Rate and General Rate revenues, respectively.

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

Q. Please identify the fiscal periods for which Minnesota Power is providing financial data in this rate case filing.

A. Financial data is provided for calendar year 2022 as the most recent fiscal year;[2] for calendar year 2023 as the projected fiscal year;[3] and for calendar year 2024 as the test year.[4] Consistent with Minnesota Rules, the Company provides average rate base, operating income, overall rate of return, and the calculation of revenue deficiency for the fiscal periods shown in Table 1, below.

Table 1: Fiscal Periods Included in Filing

Fiscal Period	Calendar Year	Schedule or Workpaper Reference
Most Recent Fiscal Year	2022	Volume 4, COS-4
Projected Fiscal Year	2023	Volume 4, COS-3
Unadjusted Test Year	2024	Volume 4, COS-2
Interim Test Year	2024	Volume 4, COS-1
Proposed Test Year	2024	Volume 3, Direct Schedule E-3

Q. Why is the 2024 calendar year the appropriate test year for this proceeding?

A. The test year begins on the proposed effective date for interim rates, which is January 1, 2024. Use of this test year results in appropriate matching of Minnesota Power's

[2] 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 Commission 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 fiscal year." ALLETE's 2023 Third Quarter financial results will be released on November 2, 2023, which is after the date of this filing. Therefore, 2022, the prior fiscal year, is the most recent fiscal year for which nine months of historical data is available, consistent with Minn. Rule 7825.3100, Subd. 10. If the Commission believes it is necessary to grant a variance to utilize this definition of the "most recent fiscal year," the Company requests a variance under Minn. Rule 7829.3200, because (i) it would be an excessive burden on the utility to have to wait to file a case until nine months of 2023 data is available, given the amount of time required to prepare a rate case filing; (ii) the variance would not adversely affect the public interest given that the Rule contemplates using the prior calendar year as the most recent fiscal year, and this has been Minnesota Power's practice for decades; and (iii) the variance would not conflict with standards imposed by law because it is consistent with Minn. Rule 7825.3100 and with past practice.

[3] Minn. Rule 7825.3100, Subp. 12 defines "Projected fiscal year" as "the fiscal year immediately following the most recent fiscal year."

[4] Minn. Rule 7825.3100, Subp. 17 defines "Test year" as "the 12-month period selected by the utility for the purpose of expressing its need for a change in rates."

costs with the revenues that are proposed to be collected under interim and final rates. Use of a budgeted test year is also consistent with what the Minnesota Public Utilities Commission ("Commission") approved in Minnesota Power's 2016 Rate Case, Docket No. E015/GR-16-664 ("2016 Rate Case") and Minnesota Power's 2021 Rate Case, Docket No. E015/GR-21-335 ("2021 Rate Case"). Further, Minnesota Power has presented a projected test year in all of its prior completed retail rate cases in Minnesota, including Docket Nos. E015/GR-21-335 (calendar year 2022), E015/GR-16-664 (calendar year 2017), E015/GR-09-1151 (calendar year 2010), E015/GR-08-415 (July 1, 2008 through June 30, 2009), E015/GR-94-001 (calendar year 1994), E015/GR-87-223 (July 1, 1987 through June 30, 1988), E015/GR-81-250 (July 1, 1981 through June 30, 1982), E015/GR-80-76 (May 1, 1980 through April 30, 1981), E015/GR-78-514 (July 1, 1978 through June 30, 1979), E015/GR-77-360 (May 1, 1977 through April 30, 1978), and E015/GR-76-408 (calendar year 1976).

Q. Why is it necessary for the Company to conduct different CCOSSs for the Interim Test Year and the Proposed Test Year?

A. As explained in more detail in Section V of my testimony, there are several differences between what has been previously approved by the Commission—and, therefore, the basis of the Interim Test Year CCOSS under Minn. Stat. § 216B.16, subd. 3—and what is being proposed by the Company in this proceeding. These differences include return on common equity ("ROE") and various rate case adjustments.

Q. Is Minnesota Power requesting any exceptions to the application of Interim Rates?

A. No. As described in the Company's Petition for Interim Rates in Volume I, Minnesota Power requests that the proposed interim rate increase be applied to all classes of Minnesota Power's retail electric customers, consistent with the rate design established in the Company's most recent rate case and Minn. Stat. § 216B.16, subd. 3. As noted in the Company's Petition for Interim Rates and discussed in the 2021 Rate Case, however, the interim rate increase is not applied to Large Power Incremental Production Service ("LP IPS"), Economy, Replacement Firm Power Service ("RFPS"), 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.

III. RATE BASE

Q. Please list the major components of rate base.

A. The major components of rate base are: Plant in Service, Construction Work in Progress ("CWIP"), Accumulated Depreciation and Amortization, and Working Capital (including Fuel Inventory, Materials and Supplies, Prepayments, and Cash Working Capital). Net Plant and Cash Working Capital are discussed in more detail below. In addition, rate base includes several smaller items: Workers' Compensation Deposit, Unamortized Upper Midwest Wind Initiative Transaction Cost, Customer Advances and Deposits, Other Deferred Credits – Hibbard, Wind Performance Deposit, and Accumulated Deferred Income Taxes.

Q. Please generally discuss the development of Unadjusted Test Year rate base in this proceeding.

A. Unadjusted Test Year rate base was developed using costs from calendar year 2022 and updated costs for 2023 and a forecast for the remainder of 2023 and 2024. Minnesota Power witness Mr. Colin B. Anderson explains Minnesota Power's method for developing its overall budget in his direct testimony.

Q. Are there rate case adjustments applicable to rate base in the test year in this proceeding?

A. Yes. Rate case adjustments are defined generally as those adjustments required by prior Commission Order, made voluntarily or per custom based on the nature of the item, or requested in this rate case specifically. All rate case adjustments, resulting in the Interim and Proposed Test Years, are discussed in Section V of my testimony.

A. <u>Net Plant</u>

Q. How was the Unadjusted Test Year net plant developed?

A. Net Plant is made up of Plant in Service, CWIP, Accumulated Depreciation, and Accumulated Amortization. Plant in Service is measured at original cost depreciated and based on the average of beginning and ending balances of the test year. Plant in Service for the test year was developed beginning with December 2022 plant balances by major function. Added to these amounts were forecast additions and retirements for 2023 and 2024 from the 2024 construction budget to arrive at average plant balances. These plant additions and retirements are also the basis for development of test year depreciation expense and, therefore, the accumulated provision for depreciation and amortization. CWIP was also obtained from actual December 2022 balances, adjusted for additions to CWIP and transfers to plant for 2023 and 2024 from the construction budget information.

B. <u>Cash Working Capital</u>

Q. How have you defined Cash Working Capital?

A. Cash Working Capital, for purposes of this proceeding, is defined as the amount of capital investors must provide to the Company, as an addition to net plant in rate base, to meet cash payment requirements during the period after expenditures are made to provide service and before the collection of revenues for that service. Thus, Cash Working Capital represents the amount of money needed to meet current operating expenses incurred prior to collecting revenues for the service provided.

When investors supply these funds, they are entitled to a return on these advances. To the extent these funds are supplied by customers, customers are entitled to have their contribution recognized as a rate base deduction. This is accomplished by including an appropriate Cash Working Capital requirement in rate base. The elements of Cash Working Capital included in this proceeding are consistent with those allowed by the Commission in each of the Company's most recent retail rate cases. As stated in its June 14, 1982 Statement of Policy on Cash Working Capital, the Commission recognizes that the most precise method of determining the Cash Working Capital requirements is to perform a lead-lag study.

Q. What procedures were followed in the preparation of the lead-lag study used in this proceeding?

A. The procedures used in the lead-lag study were initially developed to support the Company's request for a Cash Working Capital allowance in Docket No. E015/GR-78-514, which the Commission approved. The same lead-lag study methodology, adjusted to reflect various minor changes in procedures such as required payment due dates, was also the basis for the determination of Cash Working Capital in Docket Nos. E015/GR-80-76, E015/GR-81-250, E015/GR-87-223, E015/GR-94-001, E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, and E015/GR-21-335. The Cash Working Capital allowances were approved in these eight dockets with minor or no adjustments.

For this proceeding, the established lead-lag periods were determined based on a detailed study of the actual lead days and lag days experienced by the Company during calendar year 2021. Patterns in the payment of expenses and receipt of revenues do not vary significantly from one year to another. In 2018, the Company changed its standard payment terms from Net 30 to Net 60 in order to improve the Company's cash flow and Cash Working Capital. The Company has continued to implement this change to the extent that is possible with vendors and incorporate it into the lead-lag study. The Company reviewed procedures currently in effect and identified no significant changes in policies or procedures that would affect the validity of the lead-lag periods experienced during or anticipated for 2022, 2023, or the 2024 test year.

Overall, the 2021 lead-lag study and resulting Cash Working Capital calculation are consistent with the approach and methodology approved by the Commission in the Company's previous rate cases. The details of the lead-lag study are included in Volume 4, Workpapers, OS-2.

Q. How have the results of the Company's lead-lag study been used in this proceeding?

A. The results of this study have been applied to data in the CCOSS for each fiscal year to determine the Cash Working Capital components of rate base.

Q. Do you anticipate any changes to the Cash Working Capital amount during the course of the rate case proceeding?

A. Yes. As in Minnesota Power's previous retail rate cases, Cash Working Capital will need to be recalculated to reflect any changes in the Company's request during the course of the case, as well as for the Commission-approved financial adjustments that impact operations and maintenance ("O&M") expenses, rate base, and/or capital structure. As such, Cash Working Capital is likely to change over the course of this proceeding.

IV. OPERATING INCOME

A. <u>Test Year Revenue and Expense</u>

Q. Please explain the basis for Unadjusted Test Year revenues and expenses.

A. The 2024 Operating Budget provides the basis for energy sales, revenues, O&M expenses, depreciation expense, amortization expense, property taxes, payroll taxes, environmental taxes, investment tax credit, and allowance for funds used during construction ("AFUDC"). Retail revenues from electricity sales used in the Unadjusted Test Year CCOSS reflect the final rates ordered in the Company's most recent rate case (the 2021 Rate Case). These sales were developed based on budgeted sales of electricity in the 2024 Revenue Budget, as discussed in more detail by Company witness Mr. Frank L. Frederickson. Income taxes are calculated based on operating revenues and expenses, plus necessary adjustments to pretax income. The adjustments to pretax income, along with deferred income taxes and the tax credits, were developed by the Company's Tax Department based on budget data reflected in the CCOSS. AFUDC reflects interest charged on CWIP projects during the test year.

Q. How are Wheeling Revenues handled in the CCOSS?

A. Wheeling revenues from Minnesota Power's wholesale transmission customers Staples, Wadena, and Great River Energy are included in the Federal Energy Regulatory Commission ("FERC") Jurisdiction for CCOSS purposes.

Q. Are there rate case adjustments applicable to operating income in the test year in this proceeding?

A. Yes, all rate case adjustments are discussed in Section V of my testimony.

B. Revenue Credits

Q. Please summarize the revenue credits that are included in the 2024 cost of service.

A. The revenue credits for the 2024 test year are summarized in MP Exhibit ___ (Turner), Direct Schedule 2. There are several major categories of revenue credits, including:

1) Retail Non-Firm and Other Industrial
    1. Residential and Commercial/Industrial Dual Fuel;
    2. Large Power Demand Response ("LP Demand Response"); and
    3. LP Intersystem Sales (LP IPS, Economy, RFPS).
2) Sales for Resale (Off-System)
3) Other Operating Revenue
    1. Production;
    2. Transmission;
    3. Distribution;
    4. General Plant;
    5. Conservation Improvement Program; and
    6. Cost Recovery Riders.

Retail Non-Firm and Other Industrial and Sales for Resale (Off-System) are discussed below. Additional detail for all revenue credits is shown on MP Exhibit ___ (Turner) Direct Schedule 2.

1. Retail Non-Firm and Other Industrial

Q. What types of sales are included in the revenue credits for retail Non-Firm and other industrial power sales?

A. The total revenue credits on lines 1, 2, and 3 of MP Exhibit ___ (Turner), Direct Schedule 2, page 1 include revenues from interruptible sales to Minnesota Power's Residential and Commercial/Industrial Dual Fuel customers, LP Demand Response programs, and LP IPS, RFPS, Economy sales, and RFPS Service Fees for customers who own generation that is capable of serving part of their electric needs.

Q. Why are the Large Power products treated as revenue credits rather than Large Power revenue?

A. The LP Demand Response and Intersystem Sales products are separate from the Large Power customer class revenue because these revenues are not associated with providing service under the Large Power Service Schedule or any other retail rate schedule. The Economy and RFPS customers have their own generation, which they use to serve a portion of their load. Minnesota Power accredits this generation with the Midcontinent Independent System Operator ("MISO") under the requirements of MISO's Module E Resource Adequacy Program. This is similar to Minnesota Power's own generation accreditation with MISO and enables Minnesota Power to include the generation to meet system capacity reserve requirements even when it is not operating. This allows the customers to avoid buying standby service from Minnesota Power to cover generating unit outages, and it also allows Minnesota Power to use the customer generating capability to cover general system load when the large industrial customer's load is reduced. Customers with their own generation can also buy Economy/Non-Firm energy from Minnesota Power in lieu of operating their own generation when it is cost-effective to do so (*i.e.*, when the Economy energy price is lower than the customer's generation operating cost).

Q. Please describe LP Demand Response.

A. LP Demand Response includes Product A and Product C approved by the Commission in Docket No. E015/M-18-735 and the Curtailable product approved by the

Commission in Docket No. E015/M-16-534. LP Demand Response is accredited with MISO under the requirements of Resource Adequacy and curtailed only during a MISO emergency event. LP Demand Response is similar to a capacity purchase that Minnesota Power uses to satisfy MISO capacity requirements for its system, and participating customers receive a monthly billing demand credit.

Q. Please describe LP IPS, Economy, Non-Firm, and RFPS.

A. LP IPS is an interruptible energy product that is priced at Minnesota Power's incremental cost plus $10 per megawatt-hour ("MWh"). Large Power customers may use IPS for a small portion of their load (currently less than 10 percent of the customer's total load) that exceeds the firm service requirement. Because LP IPS is a non-firm incremental-cost based energy, it has historically been excluded from the Large Power customer class in the CCOSS. Similarly, customers with generation who have entered into Power Purchase Agreements with Minnesota Power are able to buy Economy/Non-Firm Energy, which is priced at Minnesota Power's incremental cost plus an energy surcharge. Customers may purchase Economy/Non-Firm energy up to the available unused capacity of the units less reserves. If the units are unavailable, the customer may purchase RFPS, which is priced at the greater of 120 percent of Minnesota Power's incremental cost or $30 per MWh.

2. <u>Sales for Resale (Off-System)</u>

Q. What are Minnesota Power's projected revenues from off-system wholesale power sales (non-requirements capacity and energy sales revenue) in the Unadjusted Test Year?

A. Budgeted capacity and energy revenues from sales to various counterparties and the wholesale market are shown on MP Exhibit ___ (Turner), Direct Schedule 2, page 2 and summarized on page 1, line 4. The capacity revenue comes from off-system sales to Minnkota Power, Oconto, Hibbing Public Utilities, Great River Energy, MISO, and 13 Northeastern Minnesota Municipal Power Agency ("NEMMPA") municipal customers. The energy revenue comes from a combination of specifically-identified bilateral sales and sales to the MISO market, including sales to Minnkota Power, MISO

Market Sales, Oconto, Hibbing Public Utilities and Non-Minnesota Power Station Service. Energy revenue also includes incremental energy sales to 13 NEMMPA municipal customers. As a result of Minnesota Power's Resolution to the 2019 Rate Case, Docket No. E015/M-20-429, any margins, positive or negative, associated with these sales (excluding Minnkota Power and Station Service) are reflected in the Company's annual Petition for Approval of the Annual Forecast of Automatic Adjustment Charges Forecast and True Up filings and have no direct impact on base rates in the test year.[5]

V. RATE CASE ADJUSTMENTS

Q. Please provide a summary of all rate case adjustments applied to the Unadjusted Test Year in this proceeding.

A. All rate case adjustments applied to rate base and operating income are included in MP Exhibit ___ (Turner), Direct Schedule 3. Each adjustment is identified by name, categorized by whether it applies to the Interim Test Year and/or the Proposed Test Year, and given an adjustment type. The adjustment type indicates whether the adjustment is required by prior Commission Order, is customary or voluntary based on the nature of the item, or requested in this rate case specifically. Each adjustment is discussed in detail below. The Total Company amounts for each rate base adjustment are shown on Volume 1, Direct Schedule B-4 (IR) for the Interim Test Year and on Volume 3, Direct Schedule B-6 for the Proposed Test Year. The Total Company amounts for each operating income adjustment are shown on Volume 1, Direct Schedule B-8 (IR) for the Interim Test Year and on Volume 3, Direct Schedule C-10 for the Proposed Test Year.

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[5] *In the Matter of Minn. Power's Petition for Approval of the Annual Forecasted Fuel and Purchased Energy Rates for the Calendar Year 2024*, Docket No. E015/AA-23-180, ANNUAL FILING (May 1, 2023).

Q. Are any of the adjustments handled differently in the Interim Test Year than they are in the Proposed Test Year?

A. Yes, as indicated in MP Exhibit ___ (Turner), Direct Schedule 3, while most adjustments are made in both the Interim Test Year and the Proposed Test Year, there are a few adjustments that are made in one and not the other.

Q. Are there any other differences between the Interim Test Year and the Proposed Test Year?

A. Yes. The Company uses a different ROE in the Interim Test Year than in the Proposed Test Year. The Commission authorized Minnesota Power to earn a 9.65 percent ROE in the 2021 Rate Case. Under Minn. Stat. § 216B.16, subd. 3, unless the Commission finds that exigent circumstances exist, the utility shall include in Interim Rates an ROE equal to that authorized by the Commission in the utility's most recent rate proceeding.

The Company is requesting Commission approval of an ROE of 10.30 percent in this proceeding, as supported by the Direct Testimony of Company witness Ms. Ann E. Bulkley. Because the requested ROE is higher than that authorized in Minnesota Power's most recent rate case proceeding, the Company uses the previously authorized, lower ROE of 9.65 percent in the Interim Test Year and the requested ROE of 10.30 percent in the Proposed Test Year.

The Company's cost of capital is included on Volume 1, Schedule C-6 (IR) for the Interim Test Year and Volume 3, Direct Schedule D-1 for the Proposed Test Year.

A. <u>Rate Base Adjustments</u>

1. <u>Asset Retirement Obligation ("ARO")</u>

Q. Please provide an explanation of the ARO adjustment.

A. In Minnesota Power's 2008 Rate Case, Docket No. E015/GR-08-415 ("2008 Rate Case"), the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment removes ARO related to the decommissioning of certain long-lived assets from rate base. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-1.

2. <u>Cost to Retire</u>

Q. Please provide an explanation of the Cost to Retire adjustment.

A. Related to the ARO adjustment above, in the 2008 Rate Case, the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment also reflects incorporation of decommissioning treatment instead of ARO. The cost to retire in accumulated depreciation on non-legal obligations is moved to a regulated liability under ARO. This adjustment puts it back into accumulated depreciation in rate base to reflect decommissioning treatment. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-2.

3. <u>Decommissioning</u>

Q. Please provide an explanation of the Decommissioning adjustment.

A. Related to the ARO and Cost to Retire adjustments above, in the 2008 Rate Case, the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment reflects incorporation of decommissioning treatment instead of ARO by including decommissioning accumulated depreciation in rate base. Details of this adjustment are included in Volume 4, Workpapers ADJ-RB-3.

4. <u>Boswell Energy Center ("BEC") 3 ("BEC 3") Environmental Project</u>

Q. Please provide an explanation of the BEC 3 Environmental Project adjustment.

A. In Minnesota Power's 2009 Rate Case, Docket No. E015/GR-09-1151 ("2009 Rate Case")), the Commission approved a settlement that provided that Minnesota Power may recover $223 million of Total Company costs associated with the BEC 3 environmental retrofit for regulatory purposes. Total BEC 3 environmental retrofit project capital additions were greater at $238.2 million Total Company ($209.5 million

MN Jurisdictional), requiring this adjustment reducing rate base. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-4.

5. Electric Vehicle Program ("EV Program")

Q. Please provide an explanation of the EV Program adjustment.

A. In this rate case, the Company is removing test year deferred program expenses recorded in Other Deferred Debits from rate base. Additional information is included in the Direct Testimony of Company witness Mr. Frederickson. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-5.

6. Electric Vehicle Service Equipment Project ("EVSE Project")

Q. Please provide an explanation of the EVSE Project adjustment.

A. In Docket No. E015/M-21-257, the Company requested deferred accounting of its proposed EVSE Project costs and expenses for consideration in a subsequent rate case. The Commission approved the request to install 16 direct current fast charging (DCFC) stations throughout its service territory, along with deferred accounting in its October 22, 2021, Order.[6] However, due to construction delays because of an unexpected vendor change, the capital costs related to the EVSE Project chargers, and its corresponding line extensions are removed from plant in service, accumulated depreciation, and accumulated deferred income taxes ("ADIT"). The Commission approved the Company's request to extend deferred accounting for the Company's EV charging investments until the Company's next rate case following this current case.[7] Additional information is included in the Direct Testimony of Company witness Mr. Frederickson. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-6.

[6] *In the Matter of Minnesota Power's Electric Vehicle Charging Infrastructure Investment*, Docket No. E015/M-21-257, ORDER APPROVING PROPOSAL AS MODIFIED, AUTHORIZING DEFERRED ACCOUNTING, AND REQUIRING REPORTING at 15–17 (Oct. 22, 2023).

[7] *In the Matter of Minnesota Power's Electric Vehicle Charging Infrastructure Investment*, Docket No. E015/M-21-257, ORDER at 1 (Sept. 12, 2023).

7. Pro Rata ADIT

Q. Please provide an explanation of the Pro Rata ADIT adjustment.

A. An Internal Revenue Service ("IRS") normalization requirement governs utilities that use forecasted test years for determination of rates, which requires calculation of average ADIT using a pro rata method. In the Company's 2016 Rate Case, the application of this normalization requirement was clarified as applying to Interim Rates but not to General Rates. Minnesota Power intends to adopt this methodology for recurring rate case proceedings—including this one. Thus, the pro rata ADIT methodology is reflected in the Interim Rate calculations but not in the General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-7.

8. Prepaid Other Post Employment Benefit ("OPEB")

Q. Please provide an explanation of the Prepaid OPEB adjustment.

A. As Company witness Mr. Patrick L. Cutshall explains in his direct testimony, Minnesota Power is not proposing to include the OPEB accumulated contributions in excess of net periodic benefit cost (or prepaid OPEB asset) in rate base. Minnesota Power's estimated test year prepaid OPEB asset is included in the Unadjusted Test Year CCOSS, represented as a 13-month average amount. Because the Company is not requesting to include its prepaid OPEB asset in rate base, the adjustment to remove the asset and associated ADIT is reflected in both the Interim Rate and General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-8.

9. Aircraft Hangar

Q. Please provide an explanation of the Aircraft Hangar adjustment.

A. As Company witness Mr. Anderson explains in his direct testimony, Minnesota Power has decided to forego recovery of any costs associated with the corporate aircraft and hangar in this rate case. The corporate aircraft that was previously owned by Minnesota Power was retired, and the new corporate aircraft is owned by ALLETE Enterprises as a non-regulated asset. The aircraft hangar is the only asset related to the aircraft still included in the Company's regulated plant balance and, thus, is adjusted out of the test year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-9.

10. Continuing Cost Recovery Riders

Q. Please provide an explanation of the Continuing Cost Recovery Riders adjustment.

A. As Company witness Mr. Shimmin explains in his direct testimony, several projects in the unadjusted test year budget will remain in cost recovery riders and thus are adjusted out of the test year. These include Camp Ripley, Community Solar Garden, and the SolarSense program under the Renewable Resources Rider ("RRR"). The Duluth Loop Project is a new project that will be included for the first time in the Company's 2024 Transmission Cost Recovery ("TCR") Rider filing and will remain in the TCR Rider until it is in-service and can be rolled into base rates in a subsequent rate case. Additional detail for these riders is included in the Direct Testimony of Company witness Mr. Shimmin and in Section VI of my testimony. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-10.

11. Taconite Harbor Energy Center ("THEC")

Q. Please provide an explanation of the THEC Regulated Asset adjustment.

A. In the Company's most recent rate case, the Commission concluded that THEC was not used and useful and should be removed from test year rate base.[8] Despite finding THEC was not used and useful during the test year, the Commission allowed recovery of the Company's expense related to THEC's annual depreciation, O&M expense, property taxes, and property insurance.[9] The Commission ordered that recovery of these expenses be limited by sunset provisions; therefore, the Company must cease recovery of its remaining depreciation expense by December 31, 2026, and cease recovery of O&M expenses once it begins decommissioning the facility.[10] The THEC

[8] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point 6 (Feb. 28, 2023) ("2021 Rate Case Order").
[9] *Id*. at Order Point 7.
[10] *Id.* at Order Points 8 and 9.

regulated asset has been excluded from the Unadjusted Test Year. The Company has filed an appeal with the Minnesota Court of Appeals regarding the Commission's decision to remove THEC from the test year rate base. Therefore, the Company is requesting the THEC regulated asset be included in Proposed Test Year 2024 rate base in this rate case. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-11.

12. Prepaid Pension Asset

Q. Please provide an explanation of the Prepaid Pension adjustment.

A. As Company witness Mr. Cutshall explains in his direct testimony, the Commission has previously ordered the Company to remove the pension plan accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset) from rate base, most recently in the Company's 2021 Rate Case.[11] The Company has filed an appeal with the Minnesota Court of Appeals regarding the Commission's decision to remove Prepaid Pension Asset from the test year rate base. As Mr. Cutshall explains, Minnesota Power is proposing to include Prepaid Pension Asset in rate base in the Proposed Test Year 2024. Minnesota Power's estimated test year prepaid pension asset is included in the Unadjusted Test Year CCOSS, represented as a 13-month average amount. Because the Company's prepaid pension asset was not previously included in rate base, the adjustment to remove the asset and associated ADIT is reflected in the Interim Rate calculations but not in the General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-12.

13. Cash Working Capital

Q. Please provide an explanation of the Cash Working Capital adjustment.

A. Cash Working Capital is adjusted to reflect the impact of the various Operating Income adjustments, including those required by Commission policies for advertising expense, economic development, charitable contributions, and organizational dues, and other expense adjustments. In addition, state and federal income taxes in Cash Working

[11] 2021 Rate Case Order at 79.

Capital reflect interest synchronization and the tax impact of the revenue deficiency. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-13.

14. Changes in Allocations due to Adjustments

Q. Please provide an explanation of the Change in Allocations due to Adjustments adjustment.

A. When bridging from the Unadjusted Test Year CCOSS to the Interim and/or the Proposed Test Year CCOSS, a difference in allocation factors used between the two causes minor rate base component amount variances that need to be accounted for. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-14.

B. Operating Income Adjustments

1. Advertising Expense

Q. Please provide an explanation of the Advertising Expense adjustment.

A. In compliance with Minn. Stat. § 216B.16, subd. 8 and the Commission's June 14, 1982, Statement of Policy on Advertising, and to be consistent with the treatment allowed in the Company's previous rate cases, certain advertising expenses are adjusted out of the test year. Recovery is allowed only for advertising designed to: (1) encourage energy conservation; (2) promote safety; (3) inform and educate consumers on the utility's financial services; and (4) disseminate information on a utility's corporate affairs to its owners.

To determine the adjustment for test year 2024, the Company used a detailed recoverability analysis of 2022 advertising expenses. The ratios developed with 2022 data were applied to the 2024 advertising budget to determine the adjustment amount. Details of this adjustment are included in Volume 3, Direct Schedule G-1 and Volume 4, Workpapers, ADJ-IS-1.

2. Charitable Contributions

Q. Please provide an explanation of the Charitable Contributions adjustment.

A. In compliance with Minn. Stat. § 216B.16, subd. 9, the Commission's June 14, 1982, Statement of Policy on Charitable Contributions, and to be consistent with the treatment allowed in the Company's previous rate cases, 50 percent of qualifying charitable contributions are adjusted out of the test year. The Commission's Policy Statement requires that a qualifying charitable contribution: (1) serve the utility's Minnesota service area; (2) be nondiscriminatory in the selection of recipients; and (3) not promote a political or special interest group. A detailed listing of qualifying 2022 charitable contributions is provided in Volume 4, Workpapers, ADJ-IS-2.

Based on Commission precedent, Minnesota Power is allowed rate recovery based on 50 percent of the Company's actual charitable giving for the previous three years and disallowed recovery of administrative costs. Minnesota Power has excluded administrative costs and calculated its charitable contributions based on 50 percent of average actual expense for the three years of 2020–2022. Details regarding the excluded administrative expense and three-year average of charitable contributions are provided in Volume 3, Direct Schedule G-2.

Minnesota Power reports its donations to the Minnesota Power Foundation ("MP Foundation") in FERC Account 426.1 on FERC Form 1. Each yearly amount includes Minnesota Power's lump sum contributions to the MP Foundation plus some smaller direct donations by Minnesota Power. The account also includes Minnesota Power sponsorships, donation expenses, and donations outside of Minnesota Power's territory. For this reason, donation amounts in FERC Form 1 will not equal the exact amounts of MP Foundation donations. The detailed listing of donations included in Volume 4, Workpapers, ADJ-IS-2 is provided as an example of the types of organizations, amounts, and service territory locations to which the MP Foundation typically makes contributions and shows Minnesota Power's compliance with the Commission's Statement of Policy on Charitable Contributions.

3. Economic Development

Q. Please provide an explanation of the Economic Development adjustment.

A. In compliance with Minn. Stat. § 216B.16, subd. 13, and to be consistent with the treatment allowed in the Company's previous rate cases, 50 percent of the Company's economic development expenses are adjusted out of the test year. Volume 3, Direct Schedule G-5 provides details regarding the Company's Economic and Community Development costs. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-3.

4. Organizational Dues

Q. Please provide an explanation of the Organizational Dues adjustment.

A. In compliance with the Commission's Statement of Policy on Organizational Dues issued June 14, 1982, and consistent with the treatment allowed in the Company's previous rate cases, certain organizations' dues related to lobbying and other disallowed expenses are adjusted out of the test year. Additionally, Economic Development costs are adjusted out and accounted for with the Economic Development charges found in Volume 4, Workpapers, ADJ-IS-3. A detailed listing of organizational dues and the calculation of the excluded amount, which consists of lobbying and other disallowed expenses that were billed along with other organizational dues, is provided in Volume 4, Workpapers, ADJ-IS-4.

5. Employee Expenses

Q. Please provide an explanation of the Employee Expenses adjustment.

A. This adjustment removes certain Board of Directors' expenses and employee expenses from the test year. The methodology for determining items to be excluded and the calculation of the adjustment is provided in the Direct Testimony of Company witness Mr. Anderson and shown in detail on Volume 3, Direct Schedule H-1. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-5.

Consistent with the Commission's decision in the Company's previous rate cases, Minnesota Power has excluded all legislative lobbying expenses from its test year.

Most lobbying expenses are recorded in FERC Account 426.4, which is not a part of regulated expense. However, as described in the Direct Testimony of Company witness Mr. Anderson, the Company's analysis determined that some indirectly-related lobbying expenses were included in other employee expense accounts. Therefore, an additional adjustment was made to exclude those lobbying expenses from the test year. This is included in the Employee Expenses adjustment.

6. Incentive Compensation

Q. Please provide an explanation of the Incentive Compensation adjustment.

A. Based on prior Commission practice and Orders in Minnesota Power's previous rate cases and other utility rate cases, Minnesota Power has made adjustments to exclude a portion of the budgeted expense for its Annual Incentive Plan ("AIP") and all of the budgeted expense for its Long-Term Incentive Plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP"), Executive Deferral Plan, Executive Investment Plan, and Legacy Employment Agreements. The incentive compensation plans are described in the Direct Testimony of Company witness Ms. Laura E. Krollman. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-6.

7. Years of Service Awards

Q. Please provide an explanation of the Years of Service Awards adjustment.

A. In the Company's most recent rate case, the Commission disallowed certain employee award expenses, including Service Awards and Retirement Awards, so the expenses must be adjusted out of the Interim Test Year 2024. However, the Company is requesting recovery of these expenses in this rate case. Company witness Ms. Krollman discusses this proposal in her direct testimony. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS 7.

8. Investor Relations

Q. Please provide an explanation of the Investor Relations adjustment.

A. As Company witness Mr. Anderson explains in his direct testimony, consistent with recent Commission decisions, Minnesota Power has adjusted out 50 percent of investor relations expense from the test year. Details of this adjustment are included in Volume4, Workpapers, ADJ-IS-8.

9. Asset Retirement Obligation

Q. Please provide an explanation of the ARO adjustment.

A. In accordance with the Commission's May 4, 2009 Order in the 2008 Rate Case, as described in Section V.A.1 of my testimony, Minnesota Power has adjusted depreciation and amortization expense and accretion expense to remove ARO. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-9.

10. Decommissioning

Q. Please provide an explanation of the Decommissioning adjustment.

A. Related to the ARO adjustment above and in accordance with the Commission's May 4, 2009 Order in the 2008 Rate Case, as described in Section V.A.3 of my testimony, Minnesota Power has adjusted depreciation expense to include decommissioning. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-10.

11. BEC Units 1 & 2 ("BEC 1&2") Regulated Asset

Q. Please provide an explanation of the BEC 1&2 Regulated Asset adjustment.

A. In the 2009 Rate Case, and in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544), the Commission approved an end of life of 2022 for BEC 1&2. When Minnesota Power retired BEC 1&2 in December 2018 (earlier than required), a regulated asset was set up to reflect this continued cost recovery, with amortization through 2022. In the Company's 2021 Rate Case, the Commission authorized the Company to amortize the 2022 expense over three years, with the last year being 2024. The Unadjusted Test Year 2024 budget does not include amortization expense for the last year, so this adjustment is to include the last year of amortization in the Interim Test Year; no Proposed Test Year adjustment is needed. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-11.

12. BEC 3 Environmental Project

Q. Please provide an explanation of the BEC 3 Environmental Project adjustment.

A. Along with the rate base adjustment described in Section V.A.4 of my testimony, there is an associated adjustment to reduce depreciation expense. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-12.

13. EVSE Project

Q. Please provide an explanation of the EVSE Project adjustment.

A. Along with the rate base adjustments described in Section V.A.6 of my testimony, this is an associated adjustment to reduce depreciation expense. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-13.

14. Service Center Sales

Q. Please provide an explanation of the Service Center Sales adjustment.

A. This adjustment combines adjustments for the sales of three service centers, land, and buildings near BEC, as well as the transfer of a loader to non-regulated operations. On June 1, 2017, Minnesota Power filed a request for Commission approval of four transactions, including the sale of its Aurora Service Center to Lakehead Constructors, Inc., the sale of its Chisholm Service Center to the United Way of Northeastern Minnesota, Inc., and the sale of land and buildings near the BEC to Airmark, Inc. d/b/a Nelson, Wood Shims. In its February 8, 2018 Order Approving Purchases and Sales with Conditions,[12] the Commission approved the transactions and required that Minnesota Power use deferred accounting to create regulatory liabilities for these transactions as recommended by the Minnesota Department of Commerce – Division

[12] *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of the Aurora Serv. Center to Lakehead Constructors, Inc.*, Docket No. E-015/PA-17-457, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of the Chisolm Serv. Center to United Way of N. Minn., Inc*. Docket No. E-015/PA-17-459, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of Land and Bldg. near the Boswell Energy Center to Airmark, Inc. d/b/a Nelson Wood Shims*, Docket No. E-015/PA-17-460, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Purchase of the Long Prairie Serv. Center from the State of Minn. Dept. of Military Affairs,* Docket No. E-015/PA-17-461, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018).

of Energy Resources ("Department"). On November 23, 2020, Minnesota Power filed a request for approval of the sale of its Crosby Service Center to Spalj Real Estate, LLC. In its January 25, 2021 Order,[13] the Commission approved the sale of the Crosby Service Center and required that Minnesota Power use deferred accounting to create a regulatory liability for the transaction as recommended by the Department. In the Commission's April 6, 2020 Order approving Minnesota Power's 2019 Remaining Life Depreciation Petition,[14] Minnesota Power was ordered to establish a regulatory liability for the loader transfer from Laskin Energy Center to the non-regulated Rapids Energy Center.

The Commission also required the Company to submit a compliance filing within 60 days of closing each transaction that included a detailed explanation and schedules for the regulatory liabilities established in connection to these four transactions and appropriate journal entries. The Aurora Service Center sale closed on December 27, 2017, and Minnesota Power submitted its compliance filing on February 26, 2018. The regulatory liability through December 2021 was $0.4 million Total Company. The Chisholm Service Center sale closed on January 17, 2018, and Minnesota Power submitted its compliance filing on March 9, 2018. The regulatory liability through December 2021 was $0.5 million Total Company. The sale of land and buildings near BEC closed on November 26, 2019, and Minnesota Power submitted its compliance filing on January 24, 2020. The regulatory liability through December 2021 was $0.1 million Total Company. The Crosby Service Center sale closed on March 8, 2021, and Minnesota Power submitted its compliance filing on April 26, 2021. The regulatory liability through December 2021 was $0.3 million Total Company. In the Commission's April 6, 2020 Order Approving Minnesota Power's 2019 Remaining Life Depreciation Petition, Minnesota Power was also ordered to submit a compliance filing within ten days of that order showing the Company's finalized calculation of any

[13] *In the Matter of Minn. Power's Approval of a Purchase Agreement with Spalj Real Estate, LLC*, Docket No. E-015/PA-20-839, ORDER (Jan. 25, 2021).
[14] *In the Matter of Minn. Power's 2019 Remaining Life Depreciation Petition*, Docket No. E-015/D-19-534, ORDER APPROVING REMAINING LIVES AND SALVAGE RATES, REQUIRING REGULATORY LIABILITY, AND REQUIRING COMPLIANCE FILING at 7 (Apr. 6, 2020).

journal entries for the relevant regulatory accounts. Minnesota Power submitted its compliance filing on April 16, 2020, and sent a supplemental compliance filing on April 21, 2020, pursuant to an informal information request from the Department. The regulatory liability through December 2021 was $0.1 million Total Company. The total combined regulatory liability balance for sales of service centers and land and buildings near BEC and transfer of a loader out of regulated is $1.4 million Total Company.

Q. What treatment was approved in the Company's 2021 Rate Case for the total service center regulatory liability?

A. In the Company's 2021 Rate Case, the Commission authorized the Company to amortize the regulated liability balances over three years and return it to customers as a credit to Other Operating Revenue, with the last year being 2024.[15] The Unadjusted Test Year 2024 budget includes the last year of this credit to Other Operating Revenue. Since Minnesota Power decided to file a rate case one year sooner than was expected when the 2021 Rate Case was filed, the Company is including the last year of amortization in the Interim Test Year. The adjustment discussed here is to remove this credit to Other Operating Revenue from the Proposed Test Year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-14.

15. <u>Conservation Expense</u>

Q. Please provide an explanation of the Conservation Expense adjustment.

A. For accounting purposes, Minnesota Power records conservation expense (Account 908) each month as its conservation expenditures and charges that are accumulated in the Conservation Cost Tracker Account ("CIP Tracker Account") are recovered from customers. Cost recovery is achieved through a combination of the Conservation Cost Recovery Charge ("CCRC") in base rates and the Conservation Program Adjustment ("CPA"). The CCRC and CPA are discussed further in Sections V.B.22 and V.B.21 of my testimony, respectively. The CPA is modified each year as part of Minnesota Power's CIP Consolidated Filing. The modified CPA is based on projected CIP

[15] 2021 Rate Case Order at Order Point 30.

spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP Tracker Account balance at the end of the prior year. Minnesota Power's 2024 budgeted conservation expense of $10.9 million (Total Company and MN Jurisdictional) in Account 908 thus includes recovery of conservation expenditures that are not limited to what Minnesota Power expects to spend on conservation programs during the test year.

Consistent with how conservation expenses were handled in Minnesota Power's prior rate cases, it is appropriate to include the projected conservation expenditures for CIP programs in the test year based on approved annual CIP budgets filed with and approved by the Department. Test year conservation expense has been adjusted to remove the $10.9 million in Minnesota Power's 2024 budget for FERC Account 908 and instead include projected 2024 expenditures of $12.5 million based on Minnesota Power's 2024–2026 Energy Conservation and Optimization (ECO) Triennial plan as submitted to the Department on June 30, 2023, in Docket No. E015/CIP-23-93. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-15. For Interim and General Rates, an updated CCRC was calculated based on the 2024 CIP Budget and test year retail energy sales excluding CIP-exempt customers. This calculation is shown in Volume 3, Direct Schedule I-1.

16. <u>Aircraft Hangar</u>

Q. Please provide an explanation of the Aircraft Hangar adjustment.

A. As described in Section V.A.9 of my testimony, Minnesota Power is not seeking recovery of any costs associated with the corporate aircraft. No corporate aircraft expense was included in the test year regulated administrative and general expense, so no adjustment is required. However, depreciation expense related to the aircraft hangar is included in the test year and is adjusted out by means of this adjustment. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-16.

17. Customer Affordability of Residential Electricity ("CARE")

Q. Please provide an explanation of the CARE adjustment.

A. Minnesota Power's Rider for Customer Affordability of Residential Electricity ("CARE Rider") provides discounted rates to qualified low-income Residential customers and is funded by an Affordability Surcharge assessed to other customers. The CARE Rider discounts and surcharge collections are accumulated in a tracker and adjusted as necessary between rate cases. Therefore, the Residential customer class discount and surcharge revenue from all customer classes are adjusted out of sales of electricity for CCOSS purposes. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-17.

18. CIP Incentive

Q. Please provide an explanation of the CIP Incentive adjustment.

A. In Minnesota Power's annual CIP Consolidated Filings, the Commission has permitted Minnesota Power to collect financial incentives for its CIP achievements and also to collect a carrying charge on its CIP tracker account balance. Because these revenues are intended to provide an incentive to the Company and to provide a return on outstanding tracker account balances, they are adjusted out of Other Operating Revenue for ratemaking purposes. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-18.

19. CIP Carrying Charge

Q. Please provide an explanation of the CIP Carrying Charge adjustment.

A. Related to the CIP Incentive adjustment above, CIP Carrying Charge revenues are adjusted out of Other Operating Revenue for ratemaking purposes. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-19.

20. CPA Incentive

Q. Please provide an explanation of the CPA Incentive adjustment.

A. The CPA Incentive revenue is the portion of revenue for the CIP incentive that is included in the CPA on customer bills. This is recovered over two years and represents the average of 2023 and 2024 CIP Incentive revenue. CPA Incentive revenue is adjusted out of Operating Revenue. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-20.

21. CPA

Q. Please provide an explanation of the CPA adjustment.

A. This is a second piece of the CPA Incentive adjustment described above. This consists of the total revenue received from customers for the CPA within the CIP Rider. The Total CPA revenue is adjusted out of Operating Revenue because the CIP Rider will continue on customer bills outside of base rates. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-21.

22. CCRC

Q. Please provide an explanation of the CCRC adjustment.

A. The CCRC credit amount related to the CIP-exempt Large Light and Power customers included in the test year budget is adjusted out of Operating Revenue because the CCRC credit amount is contained in the CIP Tracker and corresponding rates are adjusted outside of base rates. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-22.

23. Continuing Cost Recovery Riders

Q. Please provide an explanation of the Continuing Cost Recovery Riders adjustment.

A. Along with the rate base adjustment described in Section V.A.10 of my testimony, there are associated adjustments to operating expense, depreciation expense, and taxes associated with projects for which cost recovery will occur in riders. This adjustment removes: Solar O&M expense, SolarSense expense, Minnesota Solar Production Tax, Solar Renewable Energy Credit expense, Multi-Value Project transmission credits, net MISO Regional Expansion Criteria and Benefits revenue and expense, Depreciation Expense for projects with costs recovered in riders, and Property Tax expense with costs recovered in riders. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-23.

24. Oxides of Nitrogen ("NOx") Allowances

Q. Please provide an explanation of the NOx Allowances adjustment.

A. As Company witness Ms. Julie I. Pierce explains in her direct testimony, the U.S. Environmental Protection Agency ("EPA") Good Neighbor Rule ("GNR") is a federal air quality regulation that establishes additional NOx air emissions requirements for the ozone season (May–September) during the 2023–2030 timeframe. The GNR was finalized on March 15, 2023, published in the Federal Register on June 5, 2023, making the change effective starting August 4, 2023, for a partial ozone season for 2023. On May 31, 2023, Minnesota Power and other Minnesota utilities and industry ("the parties") filed a "Motion to Stay the State Implementation Plan ("SIP") Disapproval" with the United States Court of Appeals for the Eighth Circuit, which granted the stay on July 5, 2023, precluding the ability for the GNR to take effect in the State of Minnesota while a stay remains in effect. Subsequently, on August 4, 2023, the parties also filed challenges against the Federal Implementation Plan ("FIP") rule itself, in the form of a Petition for Administrative Reconsideration and Stay to the EPA, as well as a Petition for Judicial Review to the Eighth Circuit Court of Appeals. The Company expects that there will be an impact from implementation of the GNR in the 2024 test year.

To account for this, Minnesota Power is now requesting to add NOx allowance credit/cost recovery to the Rider for Fuel and Purchased Energy Charge ("FPE Rider"; also known as the Fuel Adjustment Clause ("FAC"), which is similar treatment as sulfur dioxide ("SO2") credit/costs recovery that was allowed in the Company's 2009 Rate Case. The Company has approximately $10.8 million included in the 2024 Unadjusted Test Year for NOx expense. For purposes of calculating interim rates in light of the stay, the Company has voluntarily adjusted these NOx expenses out of the 2024 Interim Test Year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-24.

25. Rate Case Expense

Q. Please provide an explanation of the Rate Case Expense adjustment.

A. This adjustment is made up of two parts: 1) the addition of the 2023 rate case expense, and 2) the removal of the amortized 2021 Rate Case expense.

The Company included in rate case expense projections for the directly-assignable costs associated with preparing and filing the rate case, including outside legal fees, expert witnesses and consultants, state agency fees, and administrative costs. Rate case expense does not include any Company labor and overheads, consistent with previous filings, and a portion of the total cost is allocated to non-regulated activities, consistent with the methodology approved by the Commission in Minnesota Power's previous rate cases. A summary of the projected rate case expenses compared to actual expenses for Minnesota Power's 2021 Rate Case and details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-25.

Projected rate case expenses were based on examining actual expenditures in the Company's 2021 Rate Case to date, as well as the Company's 2016 Rate Case. Projections for contract and professional services expenses were based on estimates of the fees for expert witnesses, consultants, and outside legal counsel who are anticipated to be used in this proceeding. Similarly, Commission regulatory assessments are projected based on actual assessments to date for the 2021 Rate Case and actual assessments for the 2016 Rate Case. Additionally, "other costs" were projected, including employee-related expenses associated with the rate case and expenses such as printing/copying charges and preparation and mailing of notices to customers.

Rate case expenses for this rate case were not included in the Unadjusted Test Year 2024 budget, meaning an adjustment is required to include these costs in both the Interim Test Year and the Proposed Test Year. Total projected rate case expenses have been amortized for a period of two years, which is the amount of time until the Company plans to file its next retail rate case.

Regarding the 2021 Rate Case expense, the Company was approved in the 2021 Rate Case to recover rate case expenses amortized over three years, with the last year being 2024. The Unadjusted Test Year 2024 budget includes the last year of 2021 Rate Case expense amortization. Since Minnesota Power decided to file a rate case one year sooner than was expected when the 2021 Rate Case was filed and since the actual costs for the 2021 Rate Case have been lower than anticipated, the Company is voluntarily foregoing recovery of the third and final year of rate case amortization from the 2021 Rate Case. Therefore, this adjustment includes the removal of the last year of amortization of the 2021 Rate Case expense.

All pieces considered, the Proposed Test Year 2024 includes rate case expenses from the 2023 rate case amortized over two years, and no rate case expenses from the 2021 Rate Case. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-25.

26. <u>THEC Regulated Asset</u>

Q. Please provide an explanation of the THEC Regulated Asset adjustment.

A. Along with the rate base adjustments described in Section V.A.11. of my testimony, there are associated adjustments to operating expense, amortization expense, and taxes. Details of this adjustment are in Volume 4, Workpapers, ADJ-IS-26.

27. <u>EV Program</u>

Q. Please provide an explanation of the EV Program adjustment.

A. As approved by the Commission in Docket No. E015/M-21-349, 2021–2023 deferred program costs are adjusted into the test year, to be amortized over two years beginning on January 1, 2024 with interim rate application. Additional detail for this adjustment is provided in the Direct Testimony of Mr. Frederickson and is included in Volume 4, Workpapers, ADJ-IS-27.

28. LP Demand Response

Q. Please provide an explanation of the LP Demand Response adjustment.

A. The Company is proposing to increase the Demand Response credit from $1.20 to $2.00 per kW, effective with final rates. Additional detail for this adjustment is provided in the Direct Testimony of Company witness Ms. Leah N. Peterson and is included in Volume 4, Workpapers, ADJ-IS-28.

29. Capacity Revenue and Expense

Q. Please provide an explanation of the Capacity Revenue and Expenses adjustment.

A. As Company witness Ms. Pierce explains in her direct testimony, Minnesota Power is requesting to move short-term (three years or less) capacity revenue and expense to a new Rider for Capacity Revenue and Expense Adjustment. The changes are shown in redlined and clean format in Volume 3, Direct Schedules J-3 and J-2, respectively, Minnesota Power Electric Rate Book, Section V, Page No. NEW-3, Rider for Capacity Revenue and Expense Adjustment.

During the Company's 2019 rate case (Docket Nos. E015/GR-19-442 and E015/M-20-429), the Commission approved the Company's ability to move energy and capacity sales credits to the FAC with capacity expense recovered through base rates. The change in the MISO Planning Reserve Auction moving from an annual to a seasonal construct creates variability and risk to the planning process. The proposed Rider for Capacity Revenue and Expense Adjustment will align revenue and near-term expense and provide less volatility and more certainty to customers and the Company and create symmetrical treatment for capacity revenue and expense.

There are three pieces to this adjustment: 1) to reflect the impacted FAC rate revenue in Present Rate Sales by Rate Class and Dual Fuel Revenue as a result of the credit no longer flowing through the FAC, 2) remove the capacity revenues credit from the CCOSS, and 3) remove the applicable capacity expenses from the CCOSS. This adjustment is reflected in the General Rate calculations but not in the Interim Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-29.

30. Interest Synchronization

Q. Please provide an explanation of the Interest Synchronization adjustment.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt multiplied by the average rate base. This calculation must be updated whenever a change in rate base, weighted cost of debt, or operating income occurs. Minnesota Power will therefore recalculate the interest synchronization expense after the final adjustments to rate base, weighted cost of debt, and operating income are determined in this case. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-30.

31. Changes in Allocations due to Adjustments

Q. Please provide an explanation of the Changes in Allocations due to Adjustments adjustment.

A. When bridging from the Unadjusted Test Year CCOSS to the Interim and/or the Proposed Test Year CCOSS, a difference in allocation factors used between the two causes minor income statement component amount variances that need to be accounted for. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-31.

VI. COST RECOVERY RIDERS AND TRACKERS

A. Cost Recovery Riders

Q. Please explain how Minnesota Power's cost recovery riders are handled in this rate case.

A. As Company witness Mr. Shimmin describes in his direct testimony, Minnesota Power currently recovers certain transmission and renewable costs through riders whose rates are determined in separate dockets based on specific revenue requirement calculations. The proposed rate case treatment for the Company's riders is explained in Mr. Shimmin's direct testimony.

By way of summary, projects and credits moving to base rates will be rolled in beginning January 1, 2024 and, as such, their revenue requirements will be included in the test year and excluded from rider recovery effective at the same time. For projects that will remain in the riders, cost recovery will continue through the applicable rider. Appropriate rate base and income statement adjustments have been made to exclude projects remaining in riders from rate base and their associated expenses from test year expenses, so no double recovery of costs takes place for these projects. Revenue to be collected through the continuing riders has also been excluded from total revenues for cost-of-service purposes. This is discussed in more detail in Section V.B.23 of my testimony.

B. <u>Conservation Improvement Program</u>

Q. How has the Company historically treated CIP costs?

A. The Commission approved a deferred debit accounting mechanism and established a CIP Tracker Account in the Company's 1987 general rate case (Docket No. E015/GR-87-223). Conservation expenditures and costs are entered into the CIP Tracker Account. These charges are recovered through a combination of base rates and the CPA. Funds in the CIP Tracker Account are subject to a carrying charge utilizing the rate from Minnesota Power's multi-year credit facility. The Commission approves the rate of recovery of the CIP Tracker Account balances in the Company's annual CIP filings, the latest of which was filed on April 1, 2023 (Docket No. E015/M-23-135).

Q. What is the current and future status of the CIP Tracker Account?

A. The CIP Tracker Account balance was $ $1,321,045.1[16] as of December 31, 2022. It is anticipated that the CIP Tracker Account will continue to be used in a manner consistent with recent years in that the entry of CIP-related charges and cost recovery amounts will be made to this account and reported in annual CIP filings.

[16] *In the Matter of Minn. Power's 2022 Conservation Improvement Program Consolidated Filing*, Docket E015/M-23-135, REPORTING ON CIP TRACKER ACCT. ACTIVITY, FINANCIAL INCENTIVES REPORT, PROPOSED CPA FACTORS AND 2022 PROJECT EVALUATIONS at 5 (Apr. 1, 2023).

Q. Please describe the existing conservation recovery mechanism.

A. Minnesota Power's conservation costs are recovered through a combination of the per-kilowatt-hour ("kWh") CCRC included in base rates and the CPA adder on customer bills. The current CCRC that was determined in Minnesota Power's 2021 Rate Case is $0.003948905 per kWh. In a Commission Order dated July 21, 2023 (Docket No. E015/M-23-135), the Commission approved Minnesota Power's revised CPA charge of $0.000306 per kWh, effective August 1, 2023, based on projected conservation spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP Tracker account balance at the end of the prior year.

Q. What is the CIP expense level included in the test year?

A. The CIP expense level for the 2024 test year is $12,531,684. This expense level is based on approved 2024 CIP spending from Minnesota Power's 2024–2026 CIP Triennial filing (Docket No. E015/CIP-23-93).

The Company plans to continue utilizing the Conservation Tracker Account and CPA mechanism to correct for over- and under-collections through base rates. Pursuant to the Commission's decision in Docket No. E015/GR-94-001, no prior tracker balances are included in the test year for recovery in base rates.

Q. What is the proposed revised CCRC to be included in base rates?

A. Based on test year conservation expenses and energy sales subject to the CCRC, Minnesota Power proposes a revised CCRC of $0.0045892 per kWh. The calculation of the revised CCRC is shown in Volume 3, Direct Schedule I-1.

Q. Will the CCRC be applied to customers who are exempt from the CIP requirements?

A. No, it will not. Consistent with currently authorized treatment, the CCRC will not apply to several large customers who have been granted exemptions from participation in CIP, Economy energy, or customers taking service under the Company's Competitive

Rate Schedules. In the 2008 Rate Case, Minnesota Power revised the CCRC methodology so that it is not built into Large Power rates as they are CIP-exempt. The same methodology for Large Power customers continues to be followed here. For other customers with CIP exemptions, the CCRC amount is refunded to them because it is built into their base rates. The test year conservation expense is allocated to retail rate classes based on each class's MWh of energy subject to the CCRC.

VII. OTHER COMPLIANCE REQUIREMENTS

A. <u>Renewable Energy Credit ("REC") Purchases</u>

Q. What was the compliance requirement related to REC purchases?

A. In its December 18, 2007 Order Establishing Initial Protocols for Trading Renewable Energy Credits (Docket Nos. E999/CI-03-869 and E999/CI-04-1616), the Commission required utilities seeking recovery of prudent costs related to registration, annual fees, and transaction costs related to REC purchases to file specific proposals for cost recovery.[17]

Q. Is Minnesota Power proposing recovery of costs related to registration, annual fees, or transaction costs related to REC purchases?

A. No. Minnesota Power has not included any REC purchases or related costs in the proposed 2024 test year. A small amount of Solar Renewable Energy Credit expense has been adjusted out of the test year as part of the Cost Recovery Riders adjustment.

B. <u>Thomson Hydro Investment Tax Credits ("ITCs")</u>

Q. Please describe the compliance requirement related to Thomson Hydro ITCs.

A. In its November 8, 2017 Order on Minnesota Power's 2017 RRR Rate Factor Filing, the Commission required that the Company "return any amortized federal investment

[17] *In the Matter of a Commission Investigation into Multi-State Tracking and Trading System for Renewable Energy Credits*, Docket No. E999/CI-04-1616, ORDER ESTABLISHING INITIAL PROTOCOLS FOR TRADING RENEWABLE ENERGY CREDITS at Order Point 9 (Dec. 18, 2007).

tax credits associated with Thomson Hydro to customers through future RRR filings until they can be included in base rates in a subsequent rate case."[18]

Q. What is the status of Minnesota Power's ITCs related to Thomson Hydro?

A. Minnesota Power will begin amortizing the Thomson Hydro ITCs in 2024, which will increase the income tax benefit. Under the IRS's normalization rules, amortization begins in the year in which the consolidated group (*i.e.*, ALLETE and all of its subsidiaries that join in its consolidated federal tax return) realizes a reduction of federal taxes payable as a result of the ITCs, which is expected in 2024.

C. Credit Card Fees

Q. What was the compliance requirement related to Credit Card Fees?

A. In its Order in the 2021 Rate Case, the Commission instructed the Company to establish a sunset provision for the amortization of the over-recovery of Credit Card Fees during the period of October 2018 to December 2022. This amortization balance of $55,816 will be sunset with the other amortizations at the end of 2024, as discussed by Company witness Mr. Anderson and ultimately factored into any true-up between interim rate and final rates in the current rate case.

VIII. CONCLUSION

Q. Does this conclude your Direct Testimony?

A. Yes.

[18] *In the Matter of Minnesota Power's 2017 Renewable Resources Rider Rate Factors*, Docket No. E015/M-16-776, ORDER at Order Point 3 (Nov. 8, 2017).

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Line No.		Calculation Note	Interim Rates COSS	Interim Rates Summary of Revenue	Interim Rates Difference	General Rates COSS	General Rates Summary of Revenue	General Rates Difference
			(1)	(2)	(3)	(4)	(5)	(6)
1	Present Rates Sales by Rate Class and Dual Fuel		$ 742,534,667	$ 742,534,697	$ 30	$ 744,753,050	$ 744,753,084	$ 34
2	Calculated Revenue Deficiency/Revenue Increase		$ 102,612,257	$ 102,618,295	$ 6,038	$ 127,852,686	$ 127,853,005	$ 319
3	Requested Rate Increase Percentage	line 2 / line 1	13.82%	13.82%		17.17%	17.17%	
4	Total Proposed Revenues	line 1 + line 2	$ 845,146,924	$ 845,152,992	$ 6,068	$ 872,605,736	$ 872,606,089	$ 353

(1) Volume 4, COS-1, Part 1, Page 1
(2) Volume 4, IR-1, Page 2
(4) Volume 3, Direct Schedule E-3, Part 1, Page 1
(5) Volume 3, Direct Schedule E-1, page 2

Notes:
a) All numbers shown are Minnesota Jurisdiction.
b) Minor differences shown in columns (3) and (6) are due to rounding in calculations.

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Line No.	Revenue Credit	Unadjusted Test Year 2024 Total Company	Unadjusted Test Year 2024 Minnesota Jurisdiction
		(1)	(2)
1	Dual Fuel	$ 10,444,883	$ 10,444,883
2	LP Intersystem Sales	$ 43,949,904	$ 37,829,282
3	LP Demand Response	$ (1,562,400)	$ (1,562,400)
4	Sales for Resale (Off-System)	$ 139,514,830	$ 121,182,985
5	Other Operating Revenue		
6	Production	$ 2,312,318	$ 2,004,704
7	Transmission	$ 85,809,815	$ 71,189,011
8	Distribution	$ 1,408,416	$ 1,334,458
9	General Plant	$ 1,152,839	$ 1,025,911
10	Conservation Improvement Program	$ 1,755,723	$ 1,755,723
11	Solar Renewable Resources Rider	$ 1,805,189	$ 1,805,189
12	Transmission Cost Recovery Rider	$ 10,873,664	$ 10,873,664
13	Total Other Operating Revenue	$ 105,117,964	$ 89,988,661
14	Total Revenue Credits	$ 297,465,181	$ 257,883,411

(1) Volume 4, COS-2, Part 4b, column (1)
(2) Volume 4, COS-2, Part 4b, column (3)

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Line No.	Sales for Resale (Off-System)	January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	Total 2024
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Capacity	**[TRADE SECRET DATA BEGINS**												
2	Aitkin Public Utilities	[redacted]												
3	Biwabik Public Utilities													
4	Buhl													
5	Ely													
6	Gilbert													
7	Keewatin													
8	Mountain Iron													
9	Pierz													
10	Proctor													
11	Randall													
12	Two Harbors													
13	Virginia													
14	Grand Rapids													
15	MISO Resource Adequacy Auction													
16	Hibbing Public Utilities													
17	GRE Capacity (Excess)													
18	Minnkota Power													
19	Oconto													
														TRADE SECRET DATA ENDS]
20	Total Capacity	$ 3,860,064	$ 3,898,161	$ 3,831,640	$ 3,822,965	$ 3,852,256	$ 4,100,335	$ 3,926,154	$ 3,902,758	$ 4,183,703	$ 4,133,588	$ 4,290,901	$ 4,076,602	$ 47,879,128
21	Energy	**[TRADE SECRET DATA BEGINS**												
22	Aitkin Public Utilities	[redacted]												
23	Biwabik Public Utilities													
24	Buhl													
25	Ely													
26	Gilbert													
27	Keewatin													
28	Mountain Iron													
29	Pierz													
30	Proctor													
31	Randall													
32	Two Harbors													
33	Virginia													
34	Grand Rapids													
35	Hibbing Public Utilities													
36	Liquidation - Minnkota Power													
37	Liquidation Sales													
38	Market Sales													
39	Non-MP Station Service													
40	Oconto													
														TRADE SECRET DATA ENDS]
41	Total Energy	$ 11,455,970	$ 9,488,151	$ 6,604,494	$ 7,949,521	$ 6,089,110	$ 5,703,266	$ 10,109,888	$ 7,843,592	$ 4,946,859	$ 6,293,606	$ 6,280,904	$ 7,507,691	$ 90,273,052
42	Other	**[TRADE SECRET DATA BEGINS**												
43	Oconto Transmission	[redacted]												
														TRADE SECRET DATA ENDS]
44	Total Other	$ 117,536	$ 110,326	$ 115,678	$ 109,811	$ 112,491	$ 110,231	$ 116,282	$ 115,453	$ 109,771	$ 113,668	$ 112,661	$ 118,742	$ 1,362,650
45	Total Sales for Resale (Off-System)	$ 15,433,570	$ 13,496,638	$ 10,551,812	$ 11,882,297	$ 10,053,857	$ 9,913,832	$ 14,152,324	$ 11,861,803	$ 9,240,333	$ 10,540,862	$ 10,684,466	$ 11,703,035	$ 139,514,830

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Line No.	Other Operating Revenue		Unadjusted Test Year 2024 Total Company (1)	Rider Recoverable (2)
1	Production			
2	Production-Demand			
3	CenturyLink (Rents Hydro Land for Building)	45400	$ 650	$ -
4	Recreation Leases	45610	$ 580,621	$ -
5	MPUC Ordered Revenue Requirement Offset - Land & Buildings	45690	$ 43,103	$ -
6	MPUC Ordered Revenue Requirement Offset - Dozers	45690	$ 39,078	$ -
7	Total Production-Demand		$ 663,452	$ -
8	Production-Energy			
9	Blandin Coal Shed Revenue	45690	$ 137,784	$ -
10	Blandin Coal Shed Revenue - WPPI	45690	$ (14,412)	$ -
11	Fly Ash Sales	45690	$ 1,331,474	$ -
12	Gypsum Sales	45690	$ 37,500	$ -
13	ND ITC Used	45690	$ 139,540	$ -
14	Oconto - Renewable Resource Energy Credits - Offset in RRR	45690	$ 16,981	$ 16,981
15	Total Production-Energy		$ 1,648,867	$ 16,981
16	Total Production		$ 2,312,319	$ 16,981
17	Transmission			
18	GRE Communication	45400	$ 401,005	$ -
19	Hibbtac Transformer Rental	45400	$ 468	$ -
20	USS Fiber Rental	45400	$ 14,880	$ -
21	GRE (MISO Revenue Sharing)	45620	$ (605,960)	$ -
22	Hibbing PU - Transmission	45620	$ 1,312,224	$ -
23	Hibbing PU - Transmission / Distribution	45620	$ 192,000	$ -
24	Manitoba Must Take Fee	45620	$ 19,337,006	$ 19,337,006
25	MISO	45620	$ 10,130,215	$ -
26	MISO Attachment O, GG, ZZ True Up - Accrual	45620	$ 3,051,700	$ -
27	MP/Square Butte - DC Line	45620	$ 15,576,000	$ -
28	NERC Alert Projects - Schedule 45 (AC)	45620	$ 5,554,385	$ -
29	NERC Alert Projects - Schedule 45 (DC)	45620	$ 1,126,248	$ -
30	RECB Sch 26 (regional Expansion Cost & Benefit)	45620	$ 19,137,236	$ 19,137,236
31	RECB Schedule 37	45620	$ 205,995	$ 205,995
32	RECB Schedule 38	45620	$ 247,017	$ 247,017
33	ACE O&M Payment LGIA (Easement)	45690	$ 165,879	$ -
34	MH Joint Operating Expense Payments	45690	$ 9,963,517	$ 9,963,517
35	Total Transmission		$ 85,809,815	$ 48,890,771
36	Distribution			
37	Late Fees-CSA	45000	$ 704,000	$ -
38	Misc Serv Rev	45100	$ 48,000	$ -
39	AEP - Meter Data Management Service Charge	45690	$ 4,546	$ -
40	Brainerd - Metering Services Fee	45690	$ 4,800	$ -
41	Hibbing PU - Energy Markets Service Fee	45690	$ 160,146	$ -
42	Joint Use/Pole Att	45400	$ 394,000	$ -
43	Nashwauk/Essar Billing & Maint Fee	45690	$ 26,436	$ -
44	SWL&P TALA Lease Payment	45690	$ 43,965	$ -
45	Oconto - Meter Data Management Service Charge	45690	$ 22,523	$ -
46	Total Distribution		$ 1,408,416	$ -
47	General Plant			
48	Enventis Rents	45400	$ 433,673	$ -
49	Xcel	45400	$ 9,313	$ -
50	Misc Bldg Mtc Revenue	45690	$ 164,583	$ -
51	MPUC Ordered Revenue Requirement Offset - Service Centers	45690	$ 378,456	$ -
52	LSP Parking Ramp	45690	$ 31,860	$ -
53	Tower Leasing	45690	$ 134,954	$ -
54	Total General Plant		$ 1,152,839	$ -
55	Cost Recovery Riders			
56	Conservation Improvement Program	45690	$ 1,755,723	$ 1,755,723
57	Solar Renewable Resources Rider	45690	$ 1,805,188	$ 1,805,188
58	Transmission Cost Recovery Rider	45690	$ 10,873,664	$ 10,873,664
59	Total Cost Recovery Riders		$ 14,434,575	$ 14,434,575
60	Total Other Operating Revenue		$ 105,117,964	$ 63,342,327

Adjustment	Interim	General	Required	Customary/ Voluntary	Requested	Workpaper Reference
Rate Base						
Asset Retirement Obligation	yes	yes	x			ADJ-RB-1
Cost to Retire	yes	yes	x			ADJ-RB-2
Decommissioning	yes	yes	x			ADJ-RB-3
Boswell 3 Environmental Project	yes	yes	x			ADJ-RB-4
EV Program	yes	yes	x			ADJ-RB-5
EVSE Project	yes	yes	x			ADJ-RB-6
Pro Rata ADIT	yes	no	x			ADJ-RB-7
Prepaid OPEB	yes	yes	x			ADJ-RB-8
Aircraft Hangar	yes	yes		x		ADJ-RB-9
Continuing Cost Recovery Riders	yes	yes		x	x	ADJ-RB-10
THEC	no	yes			x	ADJ-RB-11
Prepaid Pension	yes	no	x		x	ADJ-RB-12
Cash Working Capital	yes	yes		x		ADJ-RB-13
Changes in Allocations due to Adjustments	yes	yes		x		ADJ-RB-14
Income Statement						
Advertising Expense	yes	yes	x			ADJ-IS-1
Charitable Contributions	yes	yes	x			ADJ-IS-2
Economic Development	yes	yes	x			ADJ-IS-3
Organizational Dues	yes	yes	x			ADJ-IS-4
Employee Expenses	yes	yes	x			ADJ-IS-5
Incentive Compensation	yes	yes	x	x		ADJ-IS-6
Years of Service Awards	yes	no	x			ADJ-IS-7
Investor Relations	yes	yes	x			ADJ-IS-8
Asset Retirement Obligation	yes	yes	x			ADJ-IS-9
Decommisioning	yes	yes	x			ADJ-IS-10
Boswell 1 & 2 Regulated Asset	yes	no	x			ADJ-IS-11
Boswell 3 Environmental Project	yes	yes	x			ADJ-IS-12
EVSE Project	yes	yes	x			ADJ-IS-13
Service Center Sales	no	yes	x			ADJ-IS-14
Conservation Expense	yes	yes	x			ADJ-IS-15
Aircraft Hangar	yes	yes		x		ADJ-IS-16
CARE	yes	yes		x		ADJ-IS-17
CIP Incentive	yes	yes		x		ADJ-IS-18
CIP Carrying Charge	yes	yes		x		ADJ-IS-19
CPA Incentive	yes	yes		x		ADJ-IS-20
CPA	yes	yes		x		ADJ-IS-21
CCRC	yes	yes		x		ADJ-IS-22
Continuing Cost Recovery Riders	yes	yes		x	x	ADJ-IS-23
NOx Allowances	yes	no		x	x	ADJ-IS-24
Rate Case Expense	yes	yes		x		ADJ-IS-25
THEC	yes	yes		x		ADJ-IS-26
EV Program	yes	yes		x	x	ADJ-IS-27
LP Demand Response	no	yes			x	ADJ-IS-28
Capacity Revenue and Expense	no	yes			x	ADJ-IS-29
Interest Synchronization	yes	yes		x		ADJ-IS-30
Changes in Allocations due to Adjustments	yes	yes		x		ADJ-IS-31