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-26-199

Exhibit _____

REVENUE REQUIREMENTS

November 2, 2026

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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 Manager – Rates.

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

A. I have a Bachelor of Science in Mathematics from the College of Saint Scholastica. I have 12 years of experience in revenue requirements with the Company. I am responsible for maintaining Minnesota Power's UIPlanner application, which includes the Company's class cost of service study ("CCOSS") model. I also coordinate revenue requirement analyses and support for general rate cases, as well as other financial regulatory filings and projects.

Q. What is the purpose of the testimony you are presenting on behalf of Minnesota Power?

A. The purpose of my testimony is to support Minnesota Power's revenue requirements for the 2027 test year, which is the calendar year 2027. I address the determination of rate base and operating income, including the treatment of adjustments reflected in the Interim and Proposed Test Year CCOSSs. I also support the determination of the Minnesota jurisdictional revenue increase required for Minnesota Power to earn its requested rate of return in the Proposed Test Year and the approved rate of return in the Interim Test Year. In addition, I address certain compliance items from other dockets.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section II summarizes the Company's overall request in this rate case;

- Sections III and IV address the development of Rate Base and Operating Income, respectively, for purposes of the Company's CCOSS;
- Section V discusses ratemaking adjustments reflected in Rate Base and Operating Income for the 2027 test year; and
- Section VI addresses compliance items from other dockets.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedules to my testimony:

- 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;
- MP Exhibit ___ (Turner), Direct Schedule 3 – Rate Case Adjustments; and
- MP Exhibit ___ (Turner), Direct Schedule 4 – All-In Rate Increase.

II. SUMMARY OF 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 $116.7 million (15.48 percent) MN Jurisdictional[1] and a general rate increase of $134.4 million (17.83 percent) MN Jurisdictional. Without factoring the offsetting impact of reducing riders as some costs move to base rates, the interim rate increase is $148.9 million (19.75 percent) MN Jurisdictional, and the general rate increase is $166.6 million (22.09 percent) MN Jurisdictional.

The general rate and interim rate revenue requirements, revenue deficiency, and proposed rate increase percentage are summarized in 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

[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.

and General Rate revenue requirements, respectively. The revenue requirement results presented net of riders moving to base rates are also summarized in Volume 1, Direct Schedule B-11 (IR).

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 2025 as the most recent fiscal year,[2] for calendar year 2026 as the projected fiscal year,[3] and for calendar year 2027 as the test year.[4] Consistent with Minnesota Rules, the Company provides, for each of these fiscal periods, average rate base, operating income, overall rate of return, and the calculation of revenue deficiency, as shown in Table 1 below.

Table 1. Fiscal Periods Included in Filing

Fiscal Period	Calendar Year	Schedule or Workpaper Reference
Most Recent Fiscal Year	2025	Volume 4, COS-4
Projected Fiscal Year	2026	Volume 4, COS-3
Unadjusted Test Year	2027	Volume 4, COS-2
Interim Test Year	2027	Volume 4, COS-1
Proposed Test Year	2027	Volume 3, Direct Schedule E-3

[2] Minn. R. 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 2026 third quarter financial results will be released on or before November 27, 2026, which is after the date of this filing. Therefore, 2025, the prior fiscal year, is the most recent fiscal year for which nine months of historical data is available, consistent with Minn. R.7825.3100, Subp. 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. R. 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 2026 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. R. 7825.3100 and with past practice.

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

[4] Minn. R. 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."

Q. Why is the 2027 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, 2027. Use of this test year appropriately matches Minnesota Power's 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 last three rate cases.[5] Further, Minnesota Power has presented a projected test year in prior completed retail rate cases in Minnesota.[6]

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

A. It is necessary for the Company to conduct separate CCOSSs for the Interim Test Year and the Proposed Test Year because each study is based on different assumptions. 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, there are differences between the basis of the Interim Test Year CCOSS, calculated based on the requirements set forth in Minn. Stat. § 216B.16, subd. 3(b), and what is being proposed by the Company in this proceeding. These differences include return on equity ("ROE") and various rate case adjustments.

Q. Is Minnesota Power requesting any exceptions to the requirement in Minn. Stat. §216B.16, subd. 3(b)(3) that interim rates be applied consistent with the Company's existing rate design?

A. No. As described in the Company's Notice and Petition for Interim Rates in Volume 1, Minnesota Power requests that the proposed interim rate increase be applied to all customer classes of Minnesota Power's retail electric customers, consistent with the rate design established in the Company's most recent rate case (Docket No. E015/GR-23-155) ("2023 Rate Case"). However, as noted in the Company's Notice and Petition for

[5] Docket Nos. E015/GR-16-664; E015/GR-21-335; E015/GR-23-155.

[6] *See e.g.,* Docket Nos. E015/GR-23-155 (calendar year 2024); E015/GR-21-335 (calendar year 2022); E015/GR-16-664 (calendar year 2017); E015/GR-09-1151 (calendar year 2010).

Interim Rates and consistent with the Company's previous retail rate cases, 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.

Q. Is the Company changing the information it is providing in support of its requests in this proceeding?

A. No. In addition to the testimony of Minnesota Power witnesses, the Company is providing the same required financial information in support of general and interim rates that it has provided in the last few rate cases. In addition, the Company has reviewed other Commission orders and requirements to ensure it is providing information required since the Company's last general rate case.

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 ("CWC"). 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 how the Unadjusted Test Year rate base was developed in this proceeding.

A. Unadjusted Test Year rate base was developed using costs from calendar year 2025, updated costs for 2026, and forecasts for the remainder of 2026 and 2027. The Direct

Testimony of Company witness Joshua G. Rostollan explains Minnesota Power's method for developing its overall budget.

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 orders, 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. Utility Plant

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

A. Utility 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 2025 plant balances by major function. Added to these amounts were forecast additions and retirements for 2026 and 2027 from the 2027 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 December 2025 balances, adjusted for additions to CWIP and transfers to plant for 2026 and 2027 from the construction budget information.

B. Cash Working Capital

Q. What is Cash Working Capital?

A. For purposes of this proceeding, CWC is defined as the amount of capital that investors must provide to the Company, in addition to net plant in rate base, to meet cash payment requirements between the time when expenditures are incurred to provide service and when revenues are collected for that service. Said differently, CWC represents the

amount of money needed to pay current operating expenses 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 the appropriate CWC requirement in rate base. The elements of CWC included in this proceeding are consistent with those allowed by the Commission in 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 CWC requirements is to perform a lead-lag study.

Q. Please briefly describe how the Company prepared the lead-lag study for this proceeding.

A. The procedures used by the Company to develop the lead-lag study for this proceeding were initially developed to support the Company's request for a CWC 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 determination of CWC in the Company's subsequent rate cases. The CWC allowances were approved in these rate cases with minor or no adjustments.

For this proceeding, the 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 2023. The Company selected 2023 as the study period because payment and collection patterns do not vary significantly from one year to another. In 2018, the Company changed its standard payment terms from Net 30 to Net 60 to improve the Company's cash flow and CWC. The Company has continued to implement this change with vendors to the extent possible, and the resulting impacts are reflected in the lead-lag study. The Company also reviewed its current procedures and identified no significant

changes in policies or procedures that would affect the validity of the lead-lag periods experienced during or anticipated for 2025, 2026, or the 2027 test year.

Overall, the 2023 lead-lag study and resulting CWC calculation are consistent with the approach and methodology approved by the Commission in the Company's previous rate cases. The lead-lag study is provided 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 CWC components of rate base.

Q. Do you anticipate any changes to the CWC amount during the course of this rate case proceeding?

A. Yes. As in Minnesota Power's previous retail rate cases, CWC will need to be recalculated to reflect any changes in the Company's request during the course of the rate 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, CWC is likely to change over the course of this proceeding.

IV. OPERATING INCOME

A. Test Year Revenue and Expense

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

A. The 2027 operating budget provides the basis for energy sales, revenues, O&M expenses, depreciation expense, amortization expense, property taxes, payroll taxes, environmental taxes, investment tax credits, 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 2023 Rate Case, updated to reflect a reduced ROE from the Commission approval of the Acquisition of ALLETE, Inc. by Canada Pension Plan Investment Board ("CPPIB") and Global Infrastructure Partners

("GIP") ("Acquisition").[7] These sales were developed based on budgeted sales of electricity in the 2027 Revenue Budget. 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") or non-retail 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 2027 test year cost of service.

A. The revenue credits in the 2027 test year cost of service 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
    a. Residential and Commercial/Industrial Dual Fuel;
    b. Large Power Demand Response ("LP Demand Response"); and
    c. LP Intersystem Sales (LP IPS, Economy, RFPS).
2) Sales for Resale (Off-System)
3) Other Operating Revenue

[7] *In the Matter of the Petition of Minn. Power for Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners*, Docket No. E015/PA-24-198, Minnesota Power, ORDER APPROVING PETITION FOR ACQUISITION WITH CONDITIONS AND ESTABLISHING OTHER REQUIREMENTS (Dec. 10, 2025) (eDocket No. 202512-225721-01).

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 provided in 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, 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, Inc. ("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 allows Minnesota Power to include the participating customer's generation toward the Company's system capacity reserve requirements even when the customer's generation 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 the Company's LP Demand Response revenue.

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 the Company's LP IPS, Economy, Non-Firm, and RFPS revenue.

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. Sales for Resale (Off-System)

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 in 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 the Company's 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.[8]

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 that were applied to the Company's 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 customer or voluntary based on the nature of the item, or is requested in this rate case specifically. Each

[8] *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) (eDocket No. 20235-195432-01).

adjustment is discussed in detail below. The adjustment amounts are shown on the Company's financial schedules in this filing as shown in Table 2, below.

Table 2. Rate Case Adjustment Amount References

Component	Schedule Reference
Interim Test Year	
Rate Base	
Total Company	Volume 1, Direct Schedule B-4 (IR)
MN Jurisdiction	Volume 1, Direct Schedule B-3 (IR)
Operating Income	
Total Company	Volume 1, Direct Schedule B-8 (IR)
MN Jurisdiction	Volume 1, Direct Schedule B-7 (IR)
Proposed Test Year	
Rate Base	
Total Company	Volume 3, Direct Schedule B-6
MN Jurisdiction	Volume 3, Direct Schedule B-5
Operating Income	
Total Company	Volume 3, Direct Schedule C-10
MN Jurisdiction	Volume 3, Direct Schedule C-9

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. In the 2023 Rate Case, the Commission authorized Minnesota Power to earn

a 9.78 percent ROE. The ROE subsequently decreased to 9.65 percent under the Commission's order in the Acquisition. Under Minn. Stat. § 216B.16, subd. 3(b)(1), unless the Commission finds that exigent circumstances exist, interim rates must be calculated using 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 9.78 percent in this proceeding, as supported by the Direct Testimony of Company witness Ann E. Bulkley. Because the requested ROE is higher than what the Commission last authorized, the Company uses the previously authorized, lower ROE of 9.65 percent in the Interim Test Year and the requested ROE of 9.78 percent in the Proposed Test Year.

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

A. Rate Base Adjustments

1. Asset Retirement Obligation ("ARO")

Q. Please provide an explanation of the ARO adjustment.

A. In the Company'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.[9] In accordance with the Commission's decision and the treatment adopted in the Company's subsequent rate cases, this adjustment removes ARO related to the decommissioning of certain long-lived assets from rate base. Details of this adjustment are provided in Volume 4, Workpapers, ADJ-RB-1.

[9] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Rates in Minnesota*, Docket No. E015/GR-08-415, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (May 9, 2004) (eDocket No. 20095-37158-01).

2. Cost to Retire

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

A. The Cost to Retire adjustment is related to the ARO adjustment discussed above. In the Company's 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 treatment in subsequent Company rate cases, this adjustment also reflects incorporation of decommissioning treatment instead of the ARO method. Under the ARO method, the cost to retire associated with non-legal obligations is recorded as a regulated liability rather than included in accumulated depreciation. This adjustment reverses that treatment by restoring the cost to retire balance to accumulated depreciation for rate base purposes, consistent with the decommissioning methodology approved by the Commission. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-2.

3. Decommissioning

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. Boswell Energy Center ("BEC") 3 ("BEC 3") Environmental Project

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

A. In the Company's 2009 Rate Case, Docket No. E015/GR-09-1151 ("2009 Rate Case"), the Commission approved a settlement that authorized Minnesota Power to recover $223.0 million of Total Company costs associated with the BEC 3 environmental retrofit project. Actual BEC 3 environmental retrofit project capital additions were $238.2 million Total Company ($197.6 million MN Jurisdictional), which is greater

than the amount allowed for recovery. This adjustment reduces rate base to remove the portion of the project costs above the $223.0 million level authorized by the Commission. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-4.

5. 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, Docket No. E015/GR-16-664 ("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-5.

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

Q. Please provide an explanation of the OPEB adjustment.

A. As Company witness Tara L. Anderson explains in her 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-6.

7. Prepaid Pension

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

A. As Company witness Anderson explains, 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. However, as Company witness Anderson further explains, Minnesota Power is proposing at this time to include the Prepaid Pension asset in rate base for the Proposed Test Year 2027. 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-7.

8. Electric Vehicle ("EV") Service Equipment ("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 Company's request to install 16 direct current fast charging ("DCFC") stations throughout its service territory, along with deferred accounting in its October 22, 2021 Order.[10] 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 were 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 EVSE Project until the beginning of the test year in this rate case.[11] This adjustment, as it applies to Average Rate Base, adjusts out of rate base the deferred accounting asset. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-8.

[10] *In the Matter of Minn. 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, 2021) (eDocket No. 202110-179031-01).

[11] *In the Matter of Minn. Power's Electric Vehicle Charging Infrastructure Investment*, Docket No. E015/M-21-257, ORDER at 1 (Sept. 12, 2023) (eDocket No. 20239-198867-01).

9. EV Make Ready

Q. Please provide an explanation of the EV Make Ready adjustment.

A. As explained in the Direct Testimony of Company witness Arik C. Forsman, the Company is not requesting to recover costs related to the EV Make Ready program in this case, and thus are adjusted out of the test year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-9.

10. EV DCFC

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

A. The Company removed all costs related to EV DCFC/EVSE Project from its CCOSS in its previous rate case. In this case, the Company is requesting to recover costs from January 1, 2027 forward via base rates. Therefore, an adjustment is required to remove these costs from the Interim Rate calculations, but not from General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-10.

11. Aircraft Hangar

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

A. As explained in the Direct Testimony of Company witness Michelle A. Bleicher, Minnesota Power has decided to forego recovery of any costs associated with the corporate aircraft and hangar in this rate case. The 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-11.

12. Externally-Driven Projects

Q. Please provide an explanation of the Externally-Driven Projects adjustment.

A. Externally-Driven Projects are discussed in the Direct Testimony of Company witness Daniel W. Gunderson. This adjustment relates to project costs associated with Externally-Driven Projects that are the responsibility of the requesting customer. All of

these costs are specifically assigned to the non-retail jurisdiction in the Company's CCOSS and are removed in their entirety from the Company's CCOSS. This adjustment is made to ensure that costs associated with Externally-Driven Projects are not passed on to Minnesota Power's retail customers. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-12.

13. Continuing Cost Recovery Riders

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

A. As explained in the Direct Testimony of Company witness Levi A. Peterson, several projects in the unadjusted test year budget will remain in cost recovery riders and thus are adjusted out of the test year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-13.

14. Service Extension Costs

Q. Please provide an explanation of the Service Extension Costs adjustment.

A. As explained in the Direct Testimony of Company witness Joshua P. Goutermont, Minnesota Power is proposing changes to its service extension process and customer charges. An adjustment to the 2027 test year is required to reflect the appropriate expected plant amounts that will result from these changes. Because the Company is requesting approval of these changes in this rate case, the 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-RB-14.

15. Cash Working Capital

Q. Please provide an explanation of the CWC adjustment.

A. CWC is adjusted to reflect the impact of the various Operating Income adjustments discussed in the next section of my testimony. In addition, state and federal income taxes in CWC reflect interest synchronization and the tax impact of the revenue deficiency. Details of this adjustment are included in Volume 4, Workpapers, ADJ-RB-15.

16. Changes in Allocations Due to Adjustments ("CIADTA")

Q. Please provide an explanation of the CIADTA 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-16.

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 the test year in this rate case, the Company used a detailed recoverability analysis of its 2025 advertising expenses. The ratios developed with 2025 data were applied to the 2027 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 2025 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 from 2023-2025. 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 detail 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. 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 organization dues, is provided in Volume 4, Workpapers, ADJ-IS-4.

5. Employee Expense

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

A. This adjustment removes certain Board of Directors' expense and employee expense from the test year. The methodology for determining items to be excluded and the calculation of the adjustment is described by Company witness Bleicher and shown in detail in 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 part of regulated expense. However, as described by Company witness Bleicher, 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 Expense adjustment.

6. 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-6.

7. 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-7.

8. 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-8.

9. Conservation Expense

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

A. For accounting purposes, Minnesota Power records conservation expense (FERC Account 908) each month as it recovers conservation expenditures and charges that are accumulated in the Conservation Cost Tracker Account ("CIP Tracker Account") 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 spending, the amount recovered through base rates, carrying charges, financial

incentives, and the CIP Tracker Account balance at the end of the prior year. The Company's 2027 budgeted conservation expense of $14.97 million (Total Company and MN Jurisdictional) in FERC 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 $14.97 million in the Company's 2027 budget for FERC Account 908 and instead include projected 2027 expenditures of $17.15 million based on the Company's 2027-2029 Energy Conservation and Optimization ("ECO") Triennial Plan as submitted to the Department on June 15, 2026, in Docket No. E015/CIP-26-91. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-9. For Interim and General Rates, an updated CCRC was calculated based on the 2027 CIP Budget and test year retail energy sales excluding CIP-exempt customers. This calculation is shown in Volume 3, Direct Schedule I-1.

10. Years of Service Awards

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

A. In the Company's 2021 Rate Case (Docket No. E015/GR-21-335) ("2021 Rate Case"), and under the Settlement Agreement in the 2023 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 2027. However, the Company is requesting recovery of these expenses in this rate case. This proposal is discussed in the Direct Testimony of Company witness Wing H. Chan. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-10.

11. 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 Annual Incentive Plan ("AIP") amounts exceeding 20 percent of an individual employee's base salary and all of the budgeted expense for its Legacy Long-Term Incentive Plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP"), Executive Deferral Plan, Executive Investment Plan, and Legacy Employment Agreements. The adjustment for current LTIP expenses is discussed in Section V.B.28, below. Additionally, the incentive compensation plans are described by Company witness Chan. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-11.

12. EVSE Project

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

A. Along with the rate base adjustment described in Section V.A.8 of my testimony, the Company is proposing to amortize these deferred revenues and expenses over two years, which is the amount of time until the Company expects to file its next retail rate case. Additionally, this adjustment includes an increase for the depreciation expense for the projects which were placed in service in 2026. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-12.

13. EV DCFC

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

A. Along with the rate base adjustment described in Section V.A.10 of my testimony, the Company is requesting to recover costs related to the EV DCFC program from January 1, 2027 forward via base rates. Because these costs have been removed from the Company's CCOSS in its previous rate case, an adjustment is required to remove these costs from the Interim Rate calculations, but not from the General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-13.

14. EV Make Ready

Q. Please provide an explanation of the EV Make Ready adjustment.

A. Along with the rate base adjustment described in Section V.A.9 of my testimony, the Company is not requesting to recover costs related to the EV Make Ready program in this case. Therefore, an adjustment is required to remove these costs from both Interim Rate and General Rate calculations. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-14.

15. Externally-Driven Projects[12]

Q. Please provide an explanation of the Externally-Driven Projects adjustment.

A. Company witness Gunderson discusses Externally-Driven Projects in his Direct Testimony. Along with the rate base adjustment described in Section V.A.12 of my testimony, these expenses associated with Externally-Driven Projects are specifically assigned to the Company's non-retail jurisdiction in the Company's CCOSS and are removed in their entirety from the Company's CCOSS. This adjustment has been made in an effort to demonstrate and ensure these costs are not passed on to any retail customers. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-15.

16. Aircraft Hangar

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

A. As described in Section V.A.11 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 through this adjustment. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-16.

[12] The adjustment for this item is also referred to as "Customer Upgrades" in Volumes 1, 3, and 4.

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 2025 and 2026 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. Capacity Revenue and Expense

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

A. As approved by the Commission in the 2023 Rate Case, the Capacity Revenue and Expense Adjustment ("CREA") is a mechanism for collecting capacity purchase expenses and crediting capacity sale revenues three years in length or less. It is a combination of forecasted capacity rates for the current MISO Planning Year and capacity true up rates from previous MISO Planning Years. Consistent with the Commission's treatment in the 2023 Rate Case, capacity revenues and expenses associated with this are adjusted out of both the Interim Test Year and the Proposed Test Year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-23.

24. Employee Count

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

A. As Company witness Chan explains, the Company recognizes the uncertainty regarding timing of achieving its budgeted staffing levels in 2027 and has made a downward adjustment to its staffing levels in the Interim Test Year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-24.

25. Revenue Budget Corrections

Q. Please provide an explanation of the Revenue Budget Corrections adjustment.

A. When comparing unadjusted revenue in the test year to the revenue calculated in Volume 3, Direct Schedules E-1 and E-2, the Company calculated minor differences due to the build-up of revenue in the test year budget. These differences are accounted for as an adjustment to budgeted Operating Revenue to ensure the correct revenue amounts are used in the CCOSS. This allows present rate revenues to reconcile in the CCOSS and Volume 3, Direct Schedules E-1 and E-2. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-25.

26. 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.13 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. Additionally, revenues associated with the continuing cost recovery riders are adjusted out of the CCOSS for base rate ratemaking purposes. Details of this adjustment are provided by Company witness Levi Peterson and included in Volume 4, Workpapers, ADJ-IS-26.

27. Rate Case Expense

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

A. The Company included in its rate case expense projections the directly assignable costs associated with preparing and filing this rate case, including outside legal fees, expert witnesses, consultants, state agency fees, intervenor compensation, and administrative

costs. Consistent with the methodology approved by the Commission in Minnesota Power's previous rate cases, the projected rate case expense does not include any Company labor and overheads. A summary of the projected rate case expenses, compared to actual expenses from the 2021 Rate Case, is included in Volume 4, Workpapers, ADJ-IS-27. Since the 2023 Rate Case was resolved by an all-party settlement, the 2021 Rate Case was the Company's last fully litigated rate case and therefore provides a more suitable comparison to the 2027 forecast.

Projected rate case expenses were developed by examining actual expenditures from previous rate cases and updating these amounts based on current expectations. Projections for contract and professional services expenses are based on the estimates of the fees for expert witnesses, consultants, and outside legal counsel who are anticipated to be used in this proceeding. Commission regulatory assessments are projected based on actual assessments for the 2021 Rate Case, updated for inflation. Additionally, other costs were projected, including costs for intervenor compensation, employee-related expenses associated with the rate case, and expenses such as printing charges and the preparation and mailing of notices to customers.

Rate case expenses for this rate case were not included in the Unadjusted Test Year 2027 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 as this is the amount of time until the Company plans to file its next retail rate case.

28. Long-Term Incentive Plan

Q. Please provide an explanation of the LTIP adjustment.

A. As Company witness Chan explains, the Company is requesting recovery of its redesigned LTIP. Because this is a new program that has not previously been included in rate recovery, an adjustment is required to remove these costs from the Interim Test Year, but not the Proposed Test Year. Details of this adjustment are included in Volume 4, Workpapers, ADJ-IS-28.

29. Service Extension Costs

Q. Please provide an explanation of the Service Extension Costs adjustment.

A. Along with the rate base adjustment described in Section V.A.14 of my testimony, and as explained by Company witness Goutermont, Minnesota Power is proposing a change to its process and charges for service extensions. An adjustment to the 2027 test year is required to reflect the appropriate expected depreciation expense increase as a result of this change. Because the Company is requesting this change in this rate case, the 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. CIADTA

Q. Please provide an explanation of the CIADTA 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. OTHER COMPLIANCE REQUIREMENTS

A. Pending Reorganization of ALLETE

Q. What is the pending reorganization of ALLETE?

A. As discussed in the Direct Testimony of Company witness Jennifer J. Cady, on June 1, 2026, Minnesota Power filed an Application in Docket No. E015/M-26-227 proposing the corporate restructuring of ALLETE ("Reorganization Application"). In the Reorganization Application, the Company proposed a reorganization in which Minnesota Power will become a wholly owned subsidiary and regulated utility operating company, Minnesota Power, Inc., of the new ALLETE, Inc.

Q. Will the proposed Reorganization change the costs included in the Company's CCOSS?

A. No. The costs included in the CCOSS will remain consistent before and after implementation of the Reorganization. Under the Company's current structure, the CCOSS is developed using Minnesota Power data. To the extent certain Minnesota Power accounts contain both regulated and non-regulated activity, the Company applies established regulated allocation methodologies to ensure that only regulated costs are included in the CCOSS. These allocations are developed and maintained through the Company's accounting processes and have been consistently applied in prior rate cases.

If the Reorganization is approved and implemented, non-regulated activities would no longer reside within Minnesota Power accounting data. As a result, non-regulated costs would not be recorded within Minnesota Power's books and would therefore continue to be excluded in the CCOSS. Accordingly, the Reorganization will not result in a change to the costs reflected in the CCOSS.

Q. Does the Reorganization require any changes to the Company's cost allocation methodology for purposes of the CCOSS?

A. No. Because non-regulated costs would not exist in the CCOSS, the allocation of CCOSS costs would be unchanged from what is presented here.

Q. Have you prepared a detailed before-and-after comparison of the CCOSS under the current structure vs the Reorganization?

A. No. A detailed comparison of costs and accounting treatment before and after implementation of the Reorganization would be more appropriately addressed in the Reorganization proceeding, where the Commission will evaluate the specific impacts of that transaction.

For purposes of this rate case, the relevant consideration should be whether the costs included in the CCOSS are regulated utility costs. Under the Company's current structure, established accounting, allocation, and adjustment processes are used to ensure that only regulated costs are included in the CCOSS. Therefore, regardless of the Company's organizational structure, the CCOSS reflects only regulated utility costs. The Company's position is that a detailed before-and-after structural comparison is more appropriately considered in the Reorganization docket, while this proceeding focuses on the reasonableness of the costs and allocations included in the CCOSS used to support the Company's revenue requirement and rate design.

B. Rate Case Stay-Out Provision

Q. Please explain the rate case stay-out provision included in the Acquisition proceeding, specifically in relation to this filing.

A. As part of the Acquisition proceeding, the Company agreed to waive its right to file a rate case before November 1, 2026.[13] The Company complied with that commitment and did not file a rate case during the stay-out period. Minnesota Power had a revenue deficiency of approximately $100 million in the Projected Fiscal Year 2026, which is approximately what the Company would have asked for if it had filed a rate case as originally planned.

[13] *In the Matter of the Petition of Minn. Power for Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners*, Docket No. E015/PA-24-198, ORDER APPROVING PETITION FOR ACQUISITION WITH CONDITIONS AND ESTABLISHING OTHER REQUIREMENTS at Settlement Agreement at ¶ 1.44 (Dec. 10, 2025) (eDocket No. 202512-225721-01).

C. Comparison to Inflation

Q. Please explain the Company's inflation comparison.

A. Also as required by the Settlement Agreement in the Acquisition proceeding, the Company has compared its requested rate increase in this case to annual rate of inflation.[14] That comparison is shown in Table 3, below.

Table 3. Comparison of Request to Inflation

Interim Increase net of riders	15.48%	Volume 1, Direct Schedule A-1 (IR)
Proposed Increase net of riders	17.83%	Volume 3, Direct Schedule A-1
Inflation		
2024 Baseline		100.0
2025 Actual[15]	2.60%	102.60
2026 Estimate[16]	3.50%	106.19
2027 Estimate[17]	2.98%	109.36
Cumulative 2025-2027	**9.36%**	

While Table 3 above complies with the Commission's Acquisition Order requirement, it is important to note that inflation alone is not the only important metric to consider when determining the reasonableness of utility rates. For example, as described by Company witness Cady, the single most significant financial driver of this rate case is the Company's loss of energy sales as two large industrial customers idled their operations, which is entirely outside of the utility's control. Additionally, replacing aging assets, complying with federal environmental regulations, and investing in projects to increase resiliency in the face of extreme weather are all necessary investments regardless of the impact of inflation. Finally, it is important to note that

[14] *Id*. at Settlement Agreement at ¶1.44.
[15] Federal Reserve Bank of Minneapolis, *Consumer Price Index*, FEDERAL RESERVE BANK OF MINNEAPOLIS, available at: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator/consumer-price-index-1913-.
[16] Federal Reserve Bank of Minneapolis 2026 estimate (based on results from the third quarter of 2025 to the third quarter of 2026, which represents the best information available at this time).
[17] Federal Reserve Bank of St. Louis, *1-Year Expected Inflation October 2026,* FEDERAL RESERVE BANK OF ST. LOUIS, available at: https://fred.stlouisfed.org/series/EXPINF1YR.

while Minnesota's residential rates are the eighth lowest in the nation,[18] Minnesota residents are also benefiting from an increasingly clean power supply as utilities make progress to comply with the State's Carbon Free Standard, making the electric service they receive not only affordable but increasingly renewable.

D. All-In Rate Increase

Q. Did the Company agree to provide a schedule that shows an all-in rate increase?

A. Yes. In a June 4, 2026 Commission hearing in Docket No. E015/RP-25-127, the Company agreed to provide an all-in rate increase as part of its next rate case. A schedule showing an all-in rate increase analysis is included in MP Exhibit ___ (Turner), Direct Schedule 4. The schedule presents the overall impact of the Company's proposed rates for retail customer classes.

E. Boswell Energy Center Depreciation

Q. What is the Commission's required treatment of the remaining life of BEC Units 3, 4, and Common?

A. In the Company's 2024 and 2025 Remaining Life Depreciation Petition Dockets, the Commission approved "continued use of a 2035 estimated remaining life of BEC 3, 4, and 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."[19]

Q. How has the Company complied with this requirement when establishing depreciation expense for purposes of setting rates in this proceeding?

A. The Company has continued to use an end of life of 2035 for BEC 3, 4, and Common. This also aligns with the Company's proposal in its recently filed 2026 Remaining Life

[18] *In the Matter of Commission Investigation into Rate-Regulated Electric and Natural Gas Utility* Service, Docket No. E,G999/CI-26-341, OVERVIEW OF UTILITY AFFORDABILITY IN MINNESOTA at 14 (Oct. 13, 2026), available at: https://mn.gov/puc-stat/documents/pdf_files/PUC%20CORRECTED.pdf.

[19] *In the Matter of Minnesota Power's 2024 Remaining Life Depreciation Petition*, Docket No. E015/24-324, ORDER at 1 (Oct. 29, 2025) (eDocket No. 202510-224380-01); *In the Matter of Minnesota Power's 2025 Remaining Life Depreciation Petition*, Docket No. E015/25-342, ORDER at 1 (Jan. 27, 2026) (eDocket No. 20261-227423-01).

Petition.[20] There are no adjustments necessary in this rate case because the Company was already using the ordered and approved end of life of 2035 for these BEC production facilities, prior to calculating the revenue requirement for this case.

F. Taconite Harbor Energy Center ("THEC") Sunset Provisions

Q. Has the Company complied with the Commission's requirement from its 2021 Rate Case to establish a sunset provision ending December 31, 2026, for the Company's recovery of THEC's remaining depreciation expense?

A. Yes. Each of the Unadjusted, Interim, and Proposed Test Years do not include depreciation expense for THEC, as the assets were fully depreciated at the end of 2026.

Q. Has the Company complied with the Commission's requirement from its 2021 Rate Case to establish a sunset provision for THEC's O&M expenses, such that the Company will cease collecting these O&M expenses once it begins decommissioning the facility?

A. Yes. Each of the Unadjusted, Interim, and Proposed Test Years do not include O&M expenses for THEC.

G. Customer Energy Use Data ("CEUD")

Q. Did Minnesota Power include any costs or revenues related to data requests for anonymized CEUD in the 2027 test year?

A. No. The Company has responded to only a handful of requests for CEUD. A work order set up to track CEUD costs showed no charges in 2025 and just $1,081 to date in 2026. No related revenue was received. Therefore, no costs or revenue associated with CEUD were included in the 2027 test year.

[20] *In the Matter of Minnesota Power's 2026 Remaining Life Depreciation Petition*, Docket No. E015/26-327, INITIAL FILING at 10 (Sept. 1, 2026) (eDocket No. 20269-236018-01).

VII. CONCLUSION

Q. Please summarize your Direct Testimony for the Commission's consideration.

A. My Direct Testimony discussed the development of rate base and operating income for the Company's 2027 test year revenue requirement. I also discussed the ratemaking adjustments reflected in the Interim and Proposed Test Year CCOSSs, supported the resulting Minnesota Jurisdictional revenue requirement, and addressed certain compliance items from other dockets.

Q. Does this complete your Direct Testimony?

A. Yes.

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		$ 754,017,218	$ 754,108,634	$ 91,416	$ 754,108,669	$ 754,108,617	$ (52)
2	Calculated Revenue Deficiency/Revenue Increase		$ 148,880,924	$ 148,936,455	$ 55,531	$ 166,614,646	$ 166,614,276	$ (370)
3	Requested Rate Increase Percentage	line 2 / line 1	19.75%	19.75%		22.09%	22.09%	
4	Total Proposed Revenues	line 1 + line 2	$ 902,898,142	$ 903,045,089	$ 146,947	$ 920,723,315	$ 920,722,893	$ (422)

(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.

Line No.	Other Operating Revenue		Unadjusted Test Year 2027 Total Company	Unadjusted Test Year 2027 Rider Recoverable	Interim Test Year 2027 Total Company	Interim Test Year 2027 Rider Recoverable	Proposed Test Year 2027 Total Company	Proposed Test Year 2027 Rider Recoverable
			(1)	(2)	(3)	(4)	(5)	(6)
1	Production							
2	Fly Ash Sales	45690	$ 2,081,191	$ -	$ 2,081,191	$ -	$ 2,081,191	$ -
3	Gypsum Sales	45690	$ 15,000	$ -	$ 15,000	$ -	$ 15,000	$ -
4	Land Rental	45400	$ 750	$ -	$ 750	$ -	$ 750	$ -
5	North Dakota Investment Tax Credits - Used	45690	$ 465,133	$ -	$ 465,133	$ -	$ 465,133	$ -
6	Recreational Leases	45610	$ 250,000	$ -	$ 250,000	$ -	$ 250,000	$ -
7	Total Production		$ 2,812,074	$ -	$ 2,812,074	$ -	$ 2,812,074	$ -
8								
9	Transmission							
10	Attachment N1 - HVDC Modernization	45620	$ 40,885,817	$ -	$ 40,885,817	$ -	$ 40,885,817	$ -
11	Contract Transmission / Distribution Charge	45620	$ 204,000	$ -	$ 204,000	$ -	$ 204,000	$ -
12	Contract Transmission Charge	45620	$ 2,478,753	$ -	$ 2,478,753	$ -	$ 2,478,753	$ -
13	DC Line - Schedule 7	45620	$ 6,262,909	$ -	$ 6,262,909	$ -	$ 6,262,909	$ -
14	Fiber and Building Rental	45400	$ 401,005	$ -	$ 401,005	$ -	$ 401,005	$ -
15	Fiber Rental	45400	$ 14,880	$ -	$ 14,880	$ -	$ 14,880	$ -
16	GRE MISO Revenue Sharing	45620	$ (674,481)	$ -	$ (674,481)	$ -	$ (674,481)	$ -
17	Manitoba Joint Operating Expense Payments	45690	$ 9,360,838	$ -	$ 9,360,838	$ -	$ 9,360,838	$ -
18	Manitoba Must Take Fee	45620	$ 17,256,598	$ -	$ 17,256,598	$ -	$ 17,256,598	$ -
19	MISO Base Transmission	45620	$ 13,194,380	$ -	$ 13,194,380	$ -	$ 13,194,380	$ -
20	MISO Transmission Rate True-Up	45620	$ 5,802,700	$ -	$ 5,802,700	$ -	$ 5,802,700	$ -
21	MISO Unreserved Use credit	45690	$ -	$ -	$ -	$ -	$ -	$ -
22	NERC Alert Projects - Schedule 45	45620	$ 6,185,569	$ -	$ 6,185,569	$ -	$ 6,185,569	$ -
23	Regional Expansion Cost & Benefit (RECB) - Schedule 26	45620	$ 15,274,026	$ 15,274,026	$ -	$ -	$ -	$ -
24	Regional Expansion Cost & Benefit (RECB) - Schedule 37	45620	$ 153,695	$ 153,695	$ -	$ -	$ -	$ -
25	Regional Expansion Cost & Benefit (RECB) - Schedule 38	45620	$ 169,873	$ 169,873	$ -	$ -	$ -	$ -
26	Subsidiary O&M and Easement Payment	45690	$ 177,071	$ -	$ 177,071	$ -	$ 177,071	$ -
27	Transformer Rental	45400	$ 468	$ -	$ 468	$ -	$ 468	$ -
28	Total Transmission		$ 117,148,099	$ 15,597,593	$ 101,550,506	$ -	$ 101,550,506	$ -
29	Transmission Specific Assignment							
30	Regional Expansion Cost & Benefit (RECB) - Schedule 26A	45620	$ 40,014,078	$ -	$ 40,014,078	$ -	$ 40,014,078	$ -
31	Total Transmission Specific Assignment		$ 40,014,078	$ -	$ 40,014,078	$ -	$ 40,014,078	$ -
32	Distribution							
33	Customer Billing and Maintenance Fee	45690	$ 28,128	$ -	$ 28,128	$ -	$ 28,128	$ -
34	Electric Vehicle DCFC Stations - Third Party Revenue	45690	$ 164,446	$ -	$ -	$ -	$ 231,510	$ -
35	Energy Markets Service Fee	45690	$ 173,257	$ -	$ 173,257	$ -	$ 173,257	$ -
36	Joint Use / Pole Attachment	45400	$ 553,408	$ -	$ 553,408	$ -	$ 553,408	$ -
37	Late Fees	45000	$ 848,000	$ -	$ 848,000	$ -	$ 848,000	$ -
38	Meter Data Management Services Charge	45690	$ 4,824	$ -	$ 4,824	$ -	$ 4,824	$ -
39	Metering Services Fee	45690	$ 4,800	$ -	$ 4,800	$ -	$ 4,800	$ -
40	Miscellaneous Services	45100	$ 96,000	$ -	$ 96,000	$ -	$ 96,000	$ -
41	Subsidiary Transmission Assets Lease Payment	45690	$ 40,678	$ -	$ 40,678	$ -	$ 40,678	$ -
42	Total Distribution		$ 1,913,541	$ -	$ 1,749,095	$ -	$ 1,980,605	$ -
43	General Plant							
44	Fiber and Circuit Rental	45400	$ 307,830	$ -	$ 307,830	$ -	$ 307,830	$ -
45	LSP Parking Ramp	45690	$ 196,800	$ -	$ 196,800	$ -	$ 196,800	$ -
46	Miscellaneous Building Maintenance Revenue	45690	$ 178,704	$ -	$ 178,704	$ -	$ 178,704	$ -
47	Tower Leasing	45690	$ 170,921	$ -	$ 170,921	$ -	$ 170,921	$ -
48	Total General Plant		$ 854,254	$ -	$ 854,254	$ -	$ 854,254	$ -
49	Conservation Improvement Program	45690	$ 3,011,141	$ 3,011,141	$ -	$ -	$ -	$ -
50	Renewable Resources Rider	45690	$ 73,816,672	$ 73,816,672	$ -	$ -	$ -	$ -
51	Solar Renewable Resources Rider	45690	$ 1,335,807	$ 1,335,807	$ -	$ -	$ -	$ -
52	Transmission Cost Recovery Rider	45690	$ 67,314,201	$ 67,314,201	$ -	$ -	$ -	$ -
53	Total Cost Recovery Riders		$ 145,477,821	$ 145,477,821	$ -	$ -	$ -	$ -
54	Total Other Operating Revenue		$ 308,219,867	$ 161,075,414	$ 146,980,007	$ -	$ 147,211,517	$ -

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
Pro Rata ADIT	yes	no	x			ADJ-RB-5
Prepaid OPEB	yes	yes	x			ADJ-RB-6
Prepaid Pension Asset	yes	no	x		x	ADJ-RB-7
EVSE Project	yes	yes	x		x	ADJ-RB-8
EV Make Ready	yes	yes		x		ADJ-RB-9
EV DCFC	yes	no		x	x	ADJ-RB-10
Aircraft Hangar	yes	yes		x		ADJ-RB-11
Externally-Driven Projects	yes	yes		x		ADJ-RB-12
Continuing Cost Recovery Riders	yes	yes		x	x	ADJ-RB-13
Service Extension Costs	no	yes			x	ADJ-RB-14
Cash Working Capital	yes	yes		x		ADJ-RB-15
Changes in Allocations due to Adjustments	yes	yes		x		ADJ-RB-16
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
Asset Retirement Obligation	yes	yes	x			ADJ-IS-6
Decommissioning	yes	yes	x			ADJ-IS-7
Boswell 3 Environmental Project	yes	yes	x			ADJ-IS-8
Conservation Expense	yes	yes	x			ADJ-IS-9
Years of Service Awards	yes	no	x		x	ADJ-IS-10
Incentive Compensation	yes	yes	x	x		ADJ-IS-11
EVSE Project	no	yes	x		x	ADJ-IS-12
EV DCFC	yes	no		x	x	ADJ-IS-13
EV Make Ready	yes	yes		x		ADJ-IS-14
Externally-Driven Projects	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
Capacity Revenue and Expense	yes	yes		x		ADJ-IS-23
Reduce Employee Count	yes	no		x		ADJ-IS-24
Revenue Budget Corrections	yes	yes		x		ADJ-IS-25
Continuing Cost Recovery Riders	yes	yes		x	x	ADJ-IS-26
Rate Case Expense	yes	yes		x	x	ADJ-IS-27
LTIP	yes	no			x	ADJ-IS-28
Service Extension Costs	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

Line No.	Customer Class	Present Rate Revenue (1)	General Rate Revenue (2)	Net 2027 Revenue Change (3)	% Increase (4)
1	Residential	$ 166,589,987	$ 210,615,842	$ 44,025,855	26.43%
2	General Service	$ 111,619,148	$ 140,104,598	$ 28,485,450	25.52%
3	Large Light & Power	$ 159,207,067	$ 209,244,212	$ 50,037,145	31.43%
4	Large Power	$ 470,295,525	$ 586,817,287	$ 116,521,762	24.78%
5	Lighting	$ 4,619,571	$ 5,757,932	$ 1,138,361	24.64%
6	Subtotal by Customer Class	$ 912,331,299	$ 1,152,539,871	$ 240,208,573	26.33%
7	Dual Fuel -- Residential	$ 10,875,685	$ 12,455,111	$ 1,579,426	14.52%
8	Dual Fuel -- Comm/Ind	$ 2,080,115	$ 2,384,116	$ 304,002	14.61%
9	Subtotal Dual Fuel	$ 12,955,800	$ 14,839,227	$ 1,883,427	14.54%
10	Total by Customer Class (Sales of Electricity including Dual Fuel)	$ 925,287,098	$ 1,167,379,098	$ 242,092,000	26.16%

(1) Present Rate revenue, including cost recovery rider rates in effect 12/1/2026
(2) Proposed Rate revenue, including expected provisional approval of cost recovery rider rates in effect 1/1/2027, along with the proposed rate change in the SRRR, expected to be filed in November 2026.
(3) Column (2) - Column (1)
(4) Column (3) / Column (1)