MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**March 5, 2026**		**Agenda Item 1***
Company	Minnesota Power		
Docket No.	E-015/M-24-382		
	In the Matter of Minnesota Power's Petition for approval of its 2025 rate adjustment mechanism under its Rider for Transmission Cost Recovery.		
Issues	Should the Commission approve Minnesota Power's request of its 2025 rate adjustment mechanism under its Rider for Transmission Cost Recovery?		
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✓ **Relevant Documents**	**Date**
Minnesota Power – Refiled Petition	August 19, 2025
Department of Commerce – Comments	November 17, 2025
Large Power Intervenors – Comments	December 1, 2025
Minnesota Power – Reply Comments	December 11, 2025
Department of Commerce – Response to Reply Comments	December 19, 2025

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I. Background

On November 13, 2024, Minnesota Power (MP or the Company) filed its Petition for approval of its 2025 rate adjustment mechanism (2025 Transmission Factor) under its Rider for Transmission Cost Recovery (TCR or Rider). On April 8, 2025, MP filed a request to withdraw its Petition, with an intent to re-file at a later date. On August 19, 2025, MP re-submitted its Petition, requesting approval of its forecasted 2025 annual revenue requirements, 2024 Tracker Balance, and resulting 2025 Transmission Factors under the TCR to recover certain Minnesota jurisdictional transmission costs.

On November 17, 2025, the Department of Commerce, Division of Energy Resources (Department) filed its Comments, and requested that Minnesota Power file additional information in Reply Comments, and would provide recommendations after reviewing MP's Reply Comments.

On December 1, 2025, Large Power Intervenors filed its Comments, in which it requested for additional information and requested resolution for reported discrepancies in MP's Petition.

On December 11, 2025, Minnesota Power filed its Reply Comments, and provided the additional information requested by the Department of Commerce and the Large Power Intervenors.

On December 19, 2025, the Department filed its Response to MP's December 11, 2025 Reply Comments, and recommended approval of the Company's Petition.

II. Discussion

A. Minnesota Power – Petition

In Minnesota Power's 2025 Transmission Factor, the Company is specifically seeking approval for the following:[1]

- Recover costs related to its High Voltage Direct Current (HVDC) Modernization Project (HVDC Modernization Project or HVDC Project) for which the Commission issued a Certificate of Need (CoN) and a route permit on October 25, 2024.
- Recover costs net of revenues of transmission facilities that the Commission has approved under Minnesota Statute Section (Minn. Stat. §) 216B.243 or has certified or deemed to be certified under Minn. Stat. § 216B.2425; and
- Recover charges incurred under a federally approved Midcontinent Independent System Operator (MISO) tariff for other transmission owners' regionally planned transmission facilities to be constructed that have been determined to benefit Minnesota Power and

[1] Minnesota Power's Petition; at 3-4.

the integrated transmission system; and new transmission facilities approved by the regulatory commission of the state in which the facilities are being constructed that MISO has determined to benefit Minnesota Power or the integrated transmission system.

Additionally, this Petition also serves at the Company's annual filing requirement per Ordering Paragraph 7 of the Commission's December 3, 2020 Order (Docket No. E-015/M-19-440). Included in MP's 2025 Transmission Factor are costs associated with the following:

1. Costs associated with the HVDC Modernization Project and Duluth Loop Reliability Project.[2]
2. MISO new transmission facility net revenues or expenses that stem from the MISO Transmission Expansion Plan (MTEP)[3] and are derived from MISO's Regional Expansion and Cost Benefit (RECB) allocation methodology.
3. MISO Auction Revenue Rights (ARR) revenues[4] for the MVP that the Company is not an owner of but is allocated a portion of any revenues as a MISO member. The MVP ARR revenues the Company receives are being credited to retail customers in Minnesota Power's TCR Tracker.
4. No revenue or expenses associated with the Northland Reliability Project (NRP) and Alexandria – Big Oaks 345 kilovolt (KV) Project (Alexandria-Big Oaks Project). The exclusion of these projects resolves the concerns about alignment between costs and revenues which triggered Minnesota Power's April 8, 2025 request to the Commission for approval to withdraw its November Petition.

The Company noted that the primary reason for excluding the NRP and Alexandria-Big Oaks Project from its TCR is that these projects are more appropriately considered Federal Energy Regulatory Commission (FERC) jurisdictional projects than retail jurisdictional projects.[5] MP noted that as part of MISO's Tranche 1 LRTP portfolio, these projects have been determined to have both significant costs and system-wide benefits.

Costs associated with these projects are allocated to MISO North members through MISO's Schedule 26A, based on each entity's share of energy consumed. Minnesota Power is approximately 2.5 percent of MISO North. Revenues and expenses for LRTP investments are

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[2] Docket Nos. E-015/CN-21-140 and E-015/TL-21-141.

[3] MTEP is an annual regional expansion plan issued by MISO with three primary objectives: 1) to perform a reliability assessment of the MISO integrated transmission system; 2) to review transmission owning members transmission plans and make sure that appropriate projects are reviewed and recommended to MISO Boardof Directors for approval; and 3) to develop transmission upgrades to improve market performance.

[4] ARR is a Market Participant's entitlement to a share of revenue generated in annual Financial Transmission Rights ("FTR") auctions. A Market Participant's firm historical usage of MISO's transmission system determines its share and depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge.

[5] Minnesota Power's Petition; at 5.

billed and credited to utilities through MISO Schedule 26A.

MISO's LRTP projects are intended to provide system-wide benefits. As such, it is important to align any federal incentives administered through FERC with those bearing the risk associated with building the LRTP projects. Currently the FERC allows a higher return on equity (ROE) than the ROE approved by the Commission.

MP noted that the Minnesota Supreme Court has determined that it is solely in the utility's discretion as to which projects are included in its TCR, and it stands to reason that investors in these types of projects are entitled to the FERC-allowed ROE.[6] Removal of these projects from the TCR results to Minnesota Power's shareholders retaining the FERC-allowed ROE, which is a component of Schedule 26A Revenue. Additionally, MP's retail customers will not pay for the projects, as all cost recovery will be collected at the FERC-jurisdiction through MISO.

1. TCR Factors

The proposed 2025 TCR factors will increase an average of about 93 percent; or about 137 percent for the Large Power customers and about 58 percent for all other customers.[7] The increase reflects the negative 2023 projected tracker balance for the Large Power class included in the previous factors. The overall rate impact for Residential customers will be about 0.74 percent or about $0.76 per month and about a 1.53 percent increase for the Large Power customers.

2. Background of the TCR Rider

In 2005, the Minnesota Legislature enacted Minn. Stat. § 216B.16, subd. 7b, allowing the Commission to approve a tariff mechanism for the timely recovery through automatic annual adjustments of cost associated with new transmission facilities that have been approved by the Commission under Minn. Stat. §§ 216B.243 or 216B.2425. Additionally, Minn. Stat. § 216B.16, subd. 7b(d) specifically provides for the Commission to approve the annual rate adjustments upon receipt of a filing for a rate adjustment pursuant to the tariff established in Minn. Stat. § 216B.16, subd. 7b(b), and thorough review of the associated costs and achieved transmission system improvements.

In 2008, Minn. Stat. § 216B.16, subd. 7b was amended to allow utilities timely recovery of charges for new transmission facilities from other utilities through MISO and for new transmission facilities that are exempt from the requirements of Minn. Stat. § 216B.243. The MISO charges must be reduced or offset by any MISO revenues received by the utility and by amounts the utility charges to other regional transmission owners for the new transmission facilities, to the extent those revenues and charges have not been otherwise offset. Minn. Stat. §216B.16, subd 7b(b)(2).

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[6] Minnesota Power's Petition; at 6.

[7] Minnesota Power's Petition, Exhibit B-1.

3. Future Potentially Eligible TCR Projects

Ordering Paragraph 7 of the December 3, 2020 Order requires Minnesota Power to include in its TCR factor filing, descriptions of all potentially eligible projects that the Company will seek recovery for in the future, and the impact those projects will have on the TCR factor.

On July 25, 2022, the MISO Board of Directors unanimously approved the Tranche 1 LRTP portfolio of new transmission projects. The $10.3 billion investment includes 18 transmission projects in MISO's Midwest Sub-region that will result in more than 2,000 miles of additional transmission lines being built. Costs for these MVPs will be allocated across Northern MISO of which Minnesota Power is approximately 2.5 percent of MISO North. MP is investing in the NRP and Alexandria – Big Stone Projects based on existing ownership and Minnesota's Right of First Refusal statute. The Company is assigning these projects to the FERC jurisdiction and will not be seeking recovery of these costs through its TCR.[8]

4. Description and Context for Facilities

Minnesota Power is seeking cost recovery of incurred charges, excluding internal capitalized costs and Allowance for Funds Used During Construction (AFUDC) on internal capitalized costs, related to ongoing transmission projects as identified in this section. The Company also seeks cost recovery for investments and expenditures related to the HVDC Modernization, and Duluth Loop projects. Similarly, the Company is seeking recovery of its previously requested share of allocated cost of MTEP projects as a load serving entity within MISO.

HVDC Modernization Project

Minnesota Power is modernizing the converter stations for its 465-mile-HVDC transmission line that connects the plains of North Dakota to Northeastern Minnesota. With a planned completion by 2030, the HVDC modernization project accomplishes much needed updates for the nearly 50-year-old HVDC terminals. The project involves modernizing and upgrading both HVDC terminals for the 465-mile-long HVDC Line and interconnecting the upgraded HVDC terminals to the existing alternating-current (AC) transmission system.

In addition to the replacement of the existing HVDC terminals, the new Voltage Source Converter (VSC) HVDC technology implemented for the HVDC Project will be designed to provide voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability, all of which will enable Minnesota Power to continue providing reliable power within its service territory, position the HVDC transmission line for the future with expandable, modular technology, and establish the transmission corridor as a building block for a resilient grid across the Upper Midwest.[9]

Figure 1 shows the HVDC Modernization Project route approved by the Commission in its Order

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[8] MP's Petition; at 9.

[9] *Id*; at 14.

dated October 25, 2024.

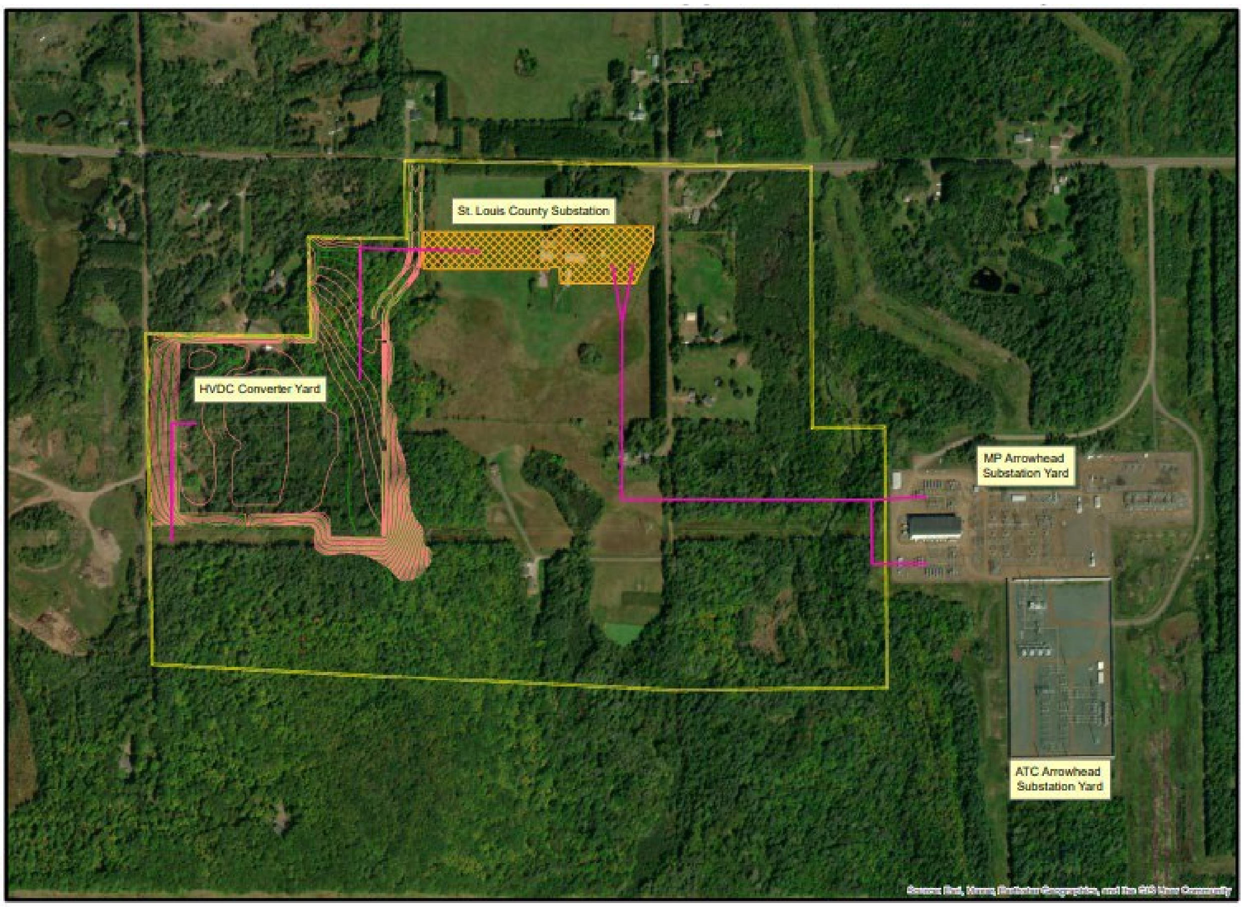


Figure 1 - HVDC Modernization Project Route

a.1. Substation and Terminal Facilities

The substations and terminals are the primary facilities and the short transmission line segments are ancillary facilities for interconnecting the HVDC terminal with the substation facilities. The Project will require a new HVDC terminal, a new St. Louis County 345 kV/230 kV substation, and upgrades to the existing Arrowhead Substation 230 kV bus.

a.2. Transmission Structure and Conductor Design

The transmission structures for the HVDC Project are anticipated to be tubular steel pole structures; however, steel lattice or wood pole structures could be used as necessary. Actual span lengths and structure heights may vary outside typical values as necessary. The new ±250 kV HVDC, 230 kV, and 345 kV steel pole structures will be approximately 60 to 180 feet tall with spans of approximately 200 to 1,000 feet.

The specific conductors for the 230 kV and 345 kV transmission lines will consist of aluminum conductor steel reinforced (ACSR) or possibly aluminum conductor steel supported (ACSS) wire and are likely to use bundled configurations (e.g., two subconductors per phase). MP noted that the conductors are selected according to the near-term and long-term capacity needs of the proposed transmission lines while also considering electrical performance characteristics.

a.3. Design Options to Accommodate Future Expansion

Design options to accommodate future expansion are a major consideration for the Project, due to the long-term significance of the HVDC Line for Minnesota Power and the region. The new VSC HVDC Converter Stations will be designed with a flexible, scalable approach that will enable their future expansion to accommodate bulk regional transfers of renewable energy. The Company is working with the HVDC supplier to procure the most current capacity and technology for the new VSC Converter Stations,[10] as well as additional expandability features to enable staged development of additional HVDC capacity to meet future regional needs.

The new St Louis County 345 kV/230 kV Substation will be designed with room for several future 345 kV line additions to accommodate regional transmission development in conjunction with increasing capacity and utilization of the HVDC line. The new substation will also include space to accommodate a second 345 kV/230 kV transformer to facilitate expanded delivery of power to the local transmission system in northeastern Minnesota.

Duluth Loop Project

The Duluth Loop Project is needed to (1) resolve severe voltage stability concerns; (2) relieve transmission line overloads; and (3) enhance the reliability of Duluth area transmission sources. The transmission system in the Duluth area has historically been supported by several coal-fired baseload generators located along Minnesota's North Shore.

To maintain a continuous supply of safe and reliable electricity while replacing the support once provided by these local coal-fired generators, the Duluth area transmission system must be upgraded. To accomplish this, transmission lines in an area known as the Duluth Loop are being constructed, reconfigured, and improved to enhance system stability and reliability.

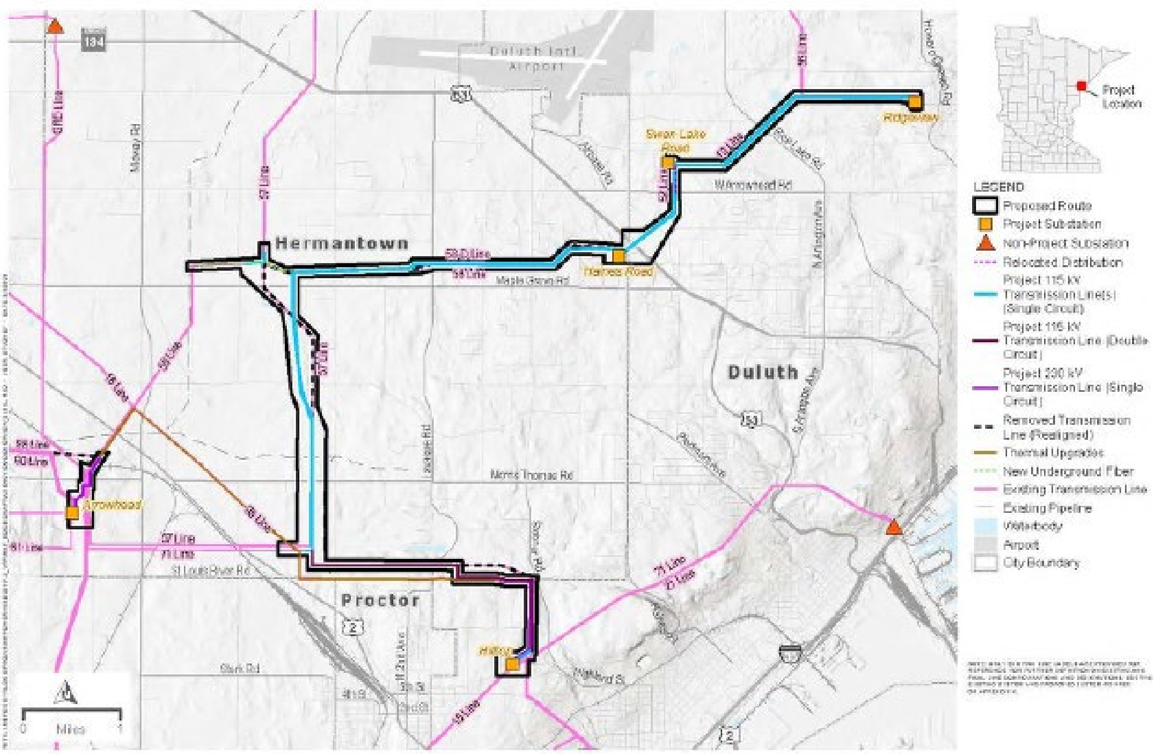
The Duluth Loop Project used a multi-stage, interactive routing process to identify route options for the proposed 115 kV line and the 230 kV line. The iterative process is designed to narrow the initial Study Area into Study Corridors, then into Route Alternatives, and finally into a Proposed Route. Through this process, Minnesota Power requested feedback from both stakeholders and the public through two public meetings, landowner mailings, stakeholder specific meetings, print and social media engagement and a project website.[11] It is through the information acquired, coupled with applicable Minnesota Statutes and Rules, potential state, federal, and local permits or approvals necessary for the Project that the Company identified the Proposed Route that was approved by the Commission in its Order dated April 3, 2023.
The Duluth Loop Project includes:

[10] Minnesota Power Petition; at 16.

[11] Id; at 17.

- Construction of about 14 miles of new 115 kV transmission line between Minnesota Power's Ridgeview, Haines Road, and Hilltop substations;
- Construction of a new approximate one-mile extension connecting an existing 230 kV transmission line to the Minnesota Power's Arrowhead substation;
- Upgrades to the Ridgeview, Hilltop, and Arrowhead substations; and
- Reconfiguration, rebuild, and upgrades to existing 115 kV and 230 kV transmission lines and communications infrastructure in the Project area.

Figure 2 shows the Commission-approved Project route, the proposed route by the Company.



b.1. Required Substation Modifications

<u>Arrowhead Substation</u>

A new 230 kV transmission line entrance will be added within the existing Arrowhead Substation located in Hermantown, Minnesota to accommodate the proposed 230kV reconfiguration establishing the Arrowhead to Hilltop 230kV line (108 Line). This new 230kV transmission line entrance will include a substation dead-end structure, circuit breaker, two switches and bus work. Existing wave traps, switches, instrument transformers, 115kV control house battery and numerous line panels will be replaced as asset renewal.

<u>Hilltop Substation</u>

The existing Hilltop Substation in Duluth, Minnesota will be expanded by approximately 0.06 acres on existing Minnesota Power property to accommodate the construction of a new 115kV transmission line entrance. This new line entrance will include a substation dead-end structure, circuit breaker, two switches and bus work. An existing 230/115kV transformer will be replaced with a higher MVA-rated transformer.[12] Furthermore, existing substation equipment including 115kV circuit breaker, two switches and various substation conductors will be replaced with higher ampacity equipment. A new 230kV circuit breaker will be added, and three existing 115kV transmission line circuit breakers will be replaced as asset renewal components.

<u>Ridgeview Substation</u>

The existing Ridgeview Substation in Duluth, Minnesota will be expanded by approximately 0.74 acres on existing Minnesota Power property to accommodate a new 115kV transmission line entrance, a future 115kV transmission line entrance, and a future capacitor bank in a ring bus configuration. The existing substation bus will be reconfigured and expanded to a six-position 115kV ring bus with three 115kV transmission line positions, two 115/14kV transformer positions, and a future 115kV transmission line position. An aging 115/14kV transformer will be replaced and relocated to a shared ring bus position with the future capacitor bank.

b.2. Required Transmission Line Modifications

The following reconfiguration, rebuild, and upgrades are required for existing transmission lines for the Duluth Loop Project: 230kV Transmission Line Work and 115kV Transmission Line Work (See details on page 20 of MP's Petition).[13]

MP related ancillary work to support the sequencing and phasing of construction as follows:[14]

> Removing distribution line crossings, relocation of distribution lines to new corridors, installation of alternative fiber communications paths to maintain communication while lines are being constructed, and relay protection panel upgrades at all three substations named above and at multiple remote ends.

MISO Transmission Projects

Minnesota Power noted that MISO is legally required to plan, develop and ensure construction of improvements to the regional transmission infrastructure. To achieve this, MISO developed STEP, a stakeholder-driven expansion planning process. Minnesota Power, and other members/participants, participate in this planning process and submits transmission projects which Minnesota Power believes will enhance the network to MISO. MISO studies all submitted

[12] Minnesota Power's Petition; at 19.
[13] Id; at 20,
[14] Id; at 21.

projects. The ones MISO determine enhanced reliability or relieve transmission congestion are included in the next annual MTEP.[15]

The Company asserted that there are three FERC-approved processes, each with separate inclusion criteria and cost allocation methods, which allow MISO to allocate costs:

1. Process for Baseline Reliability Projects (BRP) as well as generator interconnection projects.
2. Process for economic projects with regional benefits identified as Market Efficiency Projects (MEPs).
3. Process for projects assigned the MVP designation are allocated across the entire MISO footprint based on a megawatt hour charge.

Minnesota Power currently is allocated costs by MISO only for BRP that were approved by FERC during the first process.

This Petition included net MISO charges Minnesota Power incurred as a result of other transmission owners' regionally planned transmission projects determined through the MTEP process to benefit Minnesota Power.[16] Minnesota Power's net revenues from other utilities as a result of the cost allocation process are included in the transmission rider revenue requirements. Minnesota Power also included MISO ARR revenues for the MVPs that the Company is not an owner of, but is allocated a portion of any revenues as a MISO member.

1. Incentive Rate Treatment

On March 13, 2024, MISO, on behalf of ALLETE, Inc., submitted a request under sections 205 and 219 of the Federal Power Act and section 35.35 of the FERC regulations seeking incentive rate treatment for its approximately 16.5 percent investment in the Alexandria – Big Oaks Project and 47.7 percent investment in the Northland Reliability Project.[17]

On May 10, 2024, FERC issued an Order granting the requested incentives. The Company is assigning these two LRTP Tranche 1 projects to the FERC jurisdiction and are not including them in the August Petition. Therefore, the MISO Schedule 26A revenue for these two projects is excluded from the Net RECB revenue requirements.[18] The related Schedule 26A expenses MISO allocated to Minnesota Power customers for these two projects are also excluded.

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[15] MISO OATT Attachment FF (https://cdn.misoenergy.org/Attachment%20FF240221.pdf.).

[16] Minn. Stat. § 216B.16, subd. 7b(c)(1) does not require utilities to provide a description and context for facilities that result in MISO RECB charges being incurred.

[17] ALLETE also requested d authorization to recover 100 percent of prudently incurred costs of the Projects that are cancelled or abandoned for reasons beyond ALLETE's control ("Abandoned Plant Incentive"). The Abandoned Plant Incentive as approved by FERC in its May 10, 2024, Order.

[18] Minnesota Power's Petition; at 23.

2. Other Wholesale Transmission Revenues (Non-RECB)

Minnesota Power receives other wholesale transmission revenues from third-party transmission customers who are charged the Company's FERC jurisdictional MISO tariff rate for the use of its non-RECB transmission system. Minnesota regulated electric utilities' transmission assets that are not considered to be RECB projects for MISO purposes are included in the utilities' base rates rather than a transmission rider.

Some costs and revenues from non-RECB transmission projects qualify for rider recovery. In those instances, a net credit is included in the utilities' TCR Rider to account for the revenues it expects to receive from MISO for other utilities' use of the transmission asset. This net credit reflects the difference between what the utility pays MISO for using its own non-RECB transmission asset and what the utility receives from MISO for other utilities' use of the asset.

3. Project Update and Schedule for Implementation – Minn. Stat. §216B.16, subd. 7b(c)(2)

ii. HVDC Modernization Project

The anticipated permitting and construction schedule for the Project is provided in Table 1.

Table 1 - HVDC Modernization Project Schedule[19]

Activity	Timeline
Land Acquisition **Completed*	Begins April 2022
Secure Manufacturing Slot Reservation with Preferred Supplier **Completed*	January 2023
Kick off technical coordination and engagement with Preferred Supplier **Completed*	March 2023
Begin Front End Studies & Engineering Design (FEED) with Preferred Supplier **Completed*	January 2024
Certificate of Need and Route Permit Issued **Completed*	October 2024
Other Federal, State, and Local Permits Issued July **In Progress*	July 2024 – April 2026
Order Long Lead Time Equipment for AC Substations **Completed*	November 2024
Clearing Begins **In Progress*	January 2025
Construction of AC Interconnection Facilities Begins	May 2026
Receive Firm Proposal for HVDC converters from Preferred Supplier **Completed*	January 2025- April 2025
Execute Firm EPC Contract and Give Final Notice to Proceed with HVDC Manufacturing & Delivery **Completed*	May 2025
Construction of HVDC Converter Stations Begins	February 2026 – October 2026
Project In-Service	December 2028 – April 2030

iii. Duluth Loop

The work of designing and constructing the Duluth Loop Reliability Project will span several years. In the October 21, 2021 CoN, the Company stated that it anticipated that construction of

19 MP's Petition; at 24.

the Project will begin in Fall 2023 and be completed in December 2025. As reflected in Table 2 below, construction started in September 2023. Based on permitting requirements, and more detailed engineering and planning, the Project is currently expected to be completed in December 2026.

Table 2 presents the projected schedules for the various project components and status to-date.

Table 2 - Duluth Loop Project Schedule[20]

Activity	Timeframe
Certificate of Need and Route Permit Application Filed **Completed*	Fall 2021
Certificate of Need and Route Permit Issued **Completed*	Spring 2023
Land Acquisition Begins **In progress*	Spring 2023
Arrowhead Substation Construction Begins **In progress*	September 2023
ACOE Wetland (404) Permit Issued **Completed*	December 2024
Hilltop Substation Construction Begins **In progress*	Summer 2024
Alternative fiber path for 230kV system constructed **Completed*	Summer 2024
Right-of-Way Clearing Begins **Completed*	January 2025
Ridgeview Substation Construction Begins **In progress*	Spring 2025
230kV Transmission Line Construction Begins **In progress*	Spring 2025
115kV Transmission Line Construction Begins (2025 / 2026 construction seasons)	Summer 2025
Project In-Service	December 2026

The Company expected to receive the project Wetland Permit (US ACOE 404 Permit) in December 2024, which was during the allowable clearing season. The project would not begin clearing without the wetland permit and needed to wait until January 2025 to commence clearing.

Certain materials continue to experience long lead-time issues in the post-Covid-19 supply chain environment. In particular, the ACSS conductor to be used for the 115kV transmission line work is estimated to have an 80-week lead time. Conductor for the 230kV transmission line has been proactively ordered. Engineering for this project element is nearly complete, and its conductor has been ordered.

4. Minnesota Power's Costs - Minn. Stat. § 216B.16, subd. 7b(c)(3) & (4)

Minnesota Power noted that it has taken multiple steps to ensure the lowest costs to customers. The Company utilized its standard purchasing procedures to obtain competitive quotations for major purchases and awarded contracts to the lowest bidder(s) for Minnesota Power managed projects. In some cases, contracts were awarded on a single source basis to qualified contractors, based on utilizing existing partnering agreements or based upon original equipment manufacturer considerations.[21] Additionally, the Company is committed to

[20] Xcel's Petition; at 25.

[21] MP's Petition; at 26.

maximizing the benefits of the Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) for its customers.

Minnesota Power stated that it has been selected for federal funding awards to support the HVDC Modernization Project and improvements to two hydroelectric facilities. On September 30, 2024, the Company finalized the award agreement with the Department of Energy for a $50 million grant to support the HVDC Modernization Project and is currently in negotiations with the Department of Energy for $3.1 million of incentive payments for hydro facility improvements. Additionally, the Minnesota Legislature appropriated $15 million to support the HVDC Modernization Project of which Minnesota Power received $14.9 million after the Department of Commerce retained $100,000 for administration.[22]

Moreover, $10 million has been reserved from Minnesota's State Competitiveness Fund to support the cost share requirements of the federal HVDC grant and negotiation of that agreement is currently underway. As of July 17, 2025, the Company has been reimbursed $158,323 from DOE and $37,124 from the Minnesota State Competitiveness Fund.[23]

Consistent with prior TCR submissions, internal capital costs and AFUDC on internal capitalized costs have been excluded from the revenue requirement calculation.[24] The Company defines capitalized internal costs to include capitalized labor (installation and engineering labor), associated labor overheads, and administrative and general costs. Capitalized internal costs are also excluded when the projects are placed in-service and a return on rate base is included in the rider revenue requirement calculation.

Consistent with agreement with the Department in Minnesota Power's Renewable Resources Rider 2020 Renewable Factor docket,[25] the Company has updated jurisdictional and class allocation factors and rate of return (ROR) from its 2023 retail rate case[26] starting January 1, 2024 (the effective date of interim rates in that rate case).

iv. HVDC Modernization Project

The Commission-approved estimated cost range to construct both the Minnesota and North Dakota terminal upgrades for the HVDC Modernization Project is approximately $660-940 million. The cost of HVDC Converter Stations is based on the budgetary estimate provided by the HVDC supplier along with Minnesota Power's estimates for supporting internal and professional services and AFUDC. Due to the scale and complexity of the Project, MP noted that there are only two original equipment manufacturers (OEMs) in the world capable of supplying

[22] The credit to customers is reflected on pages 11-26 of Exhibit B-4.

[23] Minnesota Power's Petition; at 27.

[24] MP's Petition, Exhibit B-3; at 19-28.

[25] Docket No. E-015/M-19-523, Minnesota Power's February 14, 2020, Reply Comments, pages 7-8 and footnote 9.

[26] Docket No. E-015/GR-23-155.

the HVDC Converter Stations that can meet the size and cybersecurity requirements of the proposed design. The Company issued competitive request for proposals (RFP) to obtain a guaranteed manufacturing slot and an exclusivity agreement for further development of the Project. The OEM with the most favorable schedule proposal and lowest budgetary pricing was selected at the beginning of 2023, cementing a guaranteed latest in-service date in April 2030.

Minnesota Power is responsible for bringing the existing HVDC line to the Converter Station and constructing a new 345 kV transmission line from the point of interconnection in the HVDC Converter Station to the new AC substations being constructed for the Project. With the CoN approved, the Company stated in this Petition that it will execute a firm contract for the Project. The HVDC Converter Station cost also includes Minnesota Power's internal and professional services and AFUDC associated with the HVDC Converter Stations.

The cost of Minnesota Interconnection Facilities is generally based on the 2022 MISO (MTEP22) cost estimating guide. Minnesota Interconnection Facilities include the short extension of the HVDC line to the Converter Station, as well as all 345 kV and 230 kV facilities from the HVDC Converter Station to the Arrowhead Substation.

The cost of North Dakota Interconnection Facilities is also generally based on the MTEP22 cost estimating guide.[27] The North Dakota Interconnection Facilities include the two-mile extension of the HVDC line to the new Converter Station, as well as all 345 kV and 230 kV facilities from the HVDC Converter Station to the separately planned Nelson Lake 230 kV Substation.

Operations & Maintenance

Operations and Maintenance (O&M) Costs for the Project consist of three components: the new transmission lines, new AC substations, and new HVDC Converter Stations. The O&M costs for the HVDC Converter Stations are expected to be the most significant.

The Company stated that once constructed, O&M costs associated with the new transmission lines will be minimal for several years, since vegetation maintenance on the route corridor will occur prior to construction. Minnesota Power's average vegetation management costs for all of its transmission lines (100 kV and above) on its system was approximately $660 per line mile in 2020. The specific O&M costs for an individual transmission line varied based on the location of the line, the number of trees located along the right-of-way, the age and condition of the line, the voltage of the line, and other factors.

Over the life of the AC substation facilities, inspections will be performed regularly to maintain equipment and make necessary repairs. Minnesota Power's substation maintenance costs typically range from $50k to $100K, annually.[28]

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[27] MP's Petition; at 30.

[28] Id; at 31.

The HVDC Converter Station is expected to be staffed during normal business hours and will also be supported by dedicated engineering staff to support normal operations. During scheduled outages, additional staff will be needed to support operations. The annual HVDC O&M costs are anticipated to be approximately $4-5 million annually.

Efforts to lessen Rate Impact

Minnesota Power recognized the value and importance of ensuring affordable rates for all customer classes while also delivering reliable service and executing state energy policy goals and mandates. While approval of the HVDC Modernization Project will impact customer rates, the Company has taken steps to minimize that impact.

As stated earlier, Minnesota Power has applied for and executed contracts for several Federal and State funding opportunities.[29] The Company noted that it is committed to maximizing the benefits of the IIJA and IRA for its customers. The Company is actively monitoring funding opportunity announcements tracked and posted by the Department of Energy's Office of Clean Energy Demonstrations and Grid Deployment Office, Department of Transportation, Environmental Protection Agency, Department of Agriculture as well as the Minnesota Department of Commerce's Energy Division. Additionally, Minnesota Power is also assessing the Department of Energy's Loan Programs Office financing options.

Minnesota Power is exploring several options that could reduce the rate impact of the Project for its customers.

- **Earlier in-service date:** Given the limited number of manufacturers of the type of equipment used in HVDC terminals and highly constrained global HVDC market conditions, Minnesota Power has already secured a manufacturing slot reservation with a preferred supplier to obtain a guaranteed in-service date for the Project. This procurement strategy ensures schedule certainty for Minnesota Power's customers while stabilizing the budgetary outlook for the Project. The earliest in-service date that could be guaranteed by any manufacturer capable of delivering the Project is April 2030.

- **MISO recognition of system support in North Dakota that is added with VSC technology:** The VSC technology brings additional benefits to the MISO system that should be recognized as MISO considers long-term reliability needs. Minnesota Power has initiated discussions with MISO regarding potential wholesale Tariff changes to investigate ways to create a method to compensate Minnesota Power for these broader system benefits.

- **Federal Incentives for Shovel-Ready Project:** Minnesota Power has explored available opportunities for Federal Funding options through the IIJA and IRA as discussed above.

[29] MP's Petition; at 32.

Additionally, more Federal Funding Opportunity Announcements are expected over the coming years, and Minnesota Power anticipates pursuing them when practical for the Project.

- **State Funding:** The Company has sought funding from both the states of Minnesota and North Dakota to support the Project and further reduce its rate impact through state matching programs related to IIJA funding as well as state competitive and budgetary processes.

- **Procurement Processes:** Minnesota Power uses a competitive bidding process for all capital projects and other purchases over $50,000, ensuring projects are delivered at the best value for customers.

v. Duluth Loop

On October 21, 2021, Minnesota Power filed a CoN and Route Permit Application with the Commission, Docket No. E015/CN-21-140, for the Duluth Loop Project that received Commission approval in an Order dated April 3, 2023. The range of the estimated cost to construct the Project remains as presented in the CoN, between $50 million and $70 million. The Company's Project teams estimates that the current level of contingency is sufficient to accommodate material and labor escalation Costs, in the event of up to a full year delay of the in-service date. The Company's cost estimates in Table 3 are based on preliminary engineering considerations of the approved 115 kV Route and the 230 kV Route.[30]

Table 3 – Duluth Loop Estimated Project Costs[31]

Project Component	Low End ($Millions)	High End ($Millions)
115kV Transmission Lines	$28.2	$42.6
230kV Transmission Lines	$5.5	$8.3
Ridgeview Substation	$9.1	$10.6
Hilltop Substation	$5.6	$6.6
Arrowhead Substation	$1.2	$1.4
Haines Road Substation	$0.4	$0.5
Project Costs Total	**$50.0**	**$70.0**

Engineering has been completed and construction work awarded for work at the Arrowhead and Hilltop substations. Engineering is nearly complete for work at the Ridgeview substation, 230kV transmission line and 115kV transmission lines. Based on bids received to date and

[30] See Section 2.2, pg. 2-9, of October 21, 2021 CoN in Docket No. E-015/CN-21-140.

[31] Xcel' Petition; at 36.

designs completed to date, the project is trending near the high end of the cost range.

vi. MISO Charges and Credits

In the 2023 Transmission Factor and consistent with the 2008 legislative amendments to Minn. Stat. § 216B.16, Subd. 7b, Minnesota Power, a MISO member, is requesting current cost recovery on MISO new transmission facility charges.

1. RECB Charges

In 2010, Minnesota Power began to receive Schedule 26 revenues as a result of the RECB cost allocation process due to the inclusion of Minnesota Power projects in the MTEP. Any Schedule 26 revenues Minnesota Power receives from other utilities as a result of the RECB cost allocation process are credited against customer transmission rider revenue requirements. Similarly, the RECB Schedule 26 and 26A expenses cause an increase in customer revenue requirements.

In 2025, Minnesota Power began receiving Schedule 26A revenue related to the Company's two MISO LRTP projects. As the Company has not included those projects in the August Petition, the related Schedule 26A revenue is excluded. Similarly, the Company has excluded the Schedule 26A expense allocated to Minnesota Power customers by MISO for the Company's two related LRTP projects.

2. Auction Revenue Rights Revenues

Minnesota Power included ARR revenues for the MVPs that the Company is not an owner of but is allocated a portion of any revenues as a MISO member. The MVP ARR revenues the Company receives are being credited to retail customers in Minnesota Power's TCR Tracker. The Company projects the 2025 Minnesota jurisdictional credit to be approximately $188,312.[32]

vii. Revenue Requirements

The total recoverable retail revenue requirements proposed to be collected through the Refiled 2025 Transmission Factor for the twelve-month period ending December 31, 2025, are about $20.3 million. Estimated amounts are shown in Table 4 below and in Exhibits B-1 and B-2.

The projected 2024 ending tracker decreased slightly by the removal of Alexandria – Big Oaks revenue requirements in November and December 2024, and 2025 revenue requirements decreased by $649,507 by the removal of Alexandria - Big Oaks revenue requirements.

[32] MP's Petition, Exhibit B-2, at 3.

Table 4 - Estimated 2025 MN Jurisdictional Revenue Requirements

	Original	Refiled	Change
Projected Tracker Balance as of Dec. 31, 2024	$1,974,535	$1,964,299	$(10,236)
Duluth Loop	$3,676,303	$3,676,303	$0
HVDC Modernization	$2,541,790	$2,541,790	$0
Alexandria – Big Oaks	$649,507	$0	$(649,507)
Schedule 26 Revenue (RECB)	$(14,323,648)	$(14,323,648)	$0
Schedule 26A Revenue (RECB)	$(5,749,325)	$0	$5,749,325
Schedule 37 Revenue (RECB)	$(157,679)	$(157,679)	$0
Schedule 38 Revenue (RECB)	$(185,267)	$(185,267)	$0
Schedule 26 Expenses (RECB)	$12,383,806	$12,383,806	$0
Schedule 26A Expenses (RECB)	$14,675,843	$14,549,358	$(126,485)
Schedule 26E Expenses (RECB)	$0	$0	$0
Net RECB Revenue & Expenses	$6,643,731	$12,266,750	$5,622,840
ARR Credit	$(188,312)	$(188,312)	$0
Total:	$15,297,554	$20,260,650	$4,963,096

The estimated 2024 ending tracker balance of $1,964,299 million indicates a tracker balance for Large Power Class of $616,337 and a tracker balance of $1.3 million for all other classes.[33] The 2024 and 2025 Duluth Loop trackers do include minor Prorata ADIT credits appropriately reflecting that some of the projected plants will be in-service. The 2024 and 2025 HVDC Modernization trackers also include the ADITA related to government funding discussed below and the 2025 tracker includes the related Prorata ADIT adjustment.

viii. Revenue Requirements During Construction Work in Progress

Minnesota Power will record capital expenditures related to the TCR Rider in FERC Account 107 – CWIP. When appropriate, Minnesota Power requests a current return on CWIP on the components that are not yet placed in-service. Consistent with the terms of the 2011 Transmission Cost Recovery Factor Filing[34] and subsequent filings, internal capitalized costs are excluded from the CWIP balances as shown in capital expenditure details for each project as

[33] MP's Petition; at 39 and Exhibit B-1.
[34] Docket No. E-015/M-11-695.

shown in Exhibits B-3 to B-5.

ix. Allowance for Funds Used During Construction

The Company will calculate AFUDC for all projects and record an offsetting regulatory liability (referred to as a contra entry) equaling 100 percent of the projects' AFUDC excluding AFUDC on internal costs and include that regulatory liability as a reduction to rate base through an entry to "Pre-funded AFUDC Regulatory Liability." After the projects are placed in-service, the amount of the Pre-funded AFUDC Regulatory Liability will be amortized over the lives of the projects.

In a December 2010 Order, FERC prescribed specific accounting treatment, which requires the Company to record the Pre-funded AFUDC Regulatory Liability by debiting Account 407.3, Regulatory Debits, and crediting Account 254, Other Regulatory Liabilities, in accordance with the instructions of those accounts.

x. Return on Investment – CWIP

Revenue requirements during the construction phase of the projects will be based on the average monthly CWIP balance of projects. The Return on Investment – CWIP will be calculated on the average of the beginning and ending monthly CWIP balance until the projects are placed in-service. The total annual revenue requirements are the sum of the monthly current return on CWIP calculations until the projects are placed in-service. Internal capitalized costs and AFUDC on internal costs are excluded from the CWIP balances as discussed above.

<u>Return on Equity Component</u>

Beginning in 2024 the return on investment was updated based on Minnesota Power's last retail rate case. Minnesota Power will use the average monthly CWIP balance multiplied by the after-tax equity return rate and the equity percentage of the allowed capital structure from the last rate case to calculate the return on equity component of the revenue requirement calculation.

<u>Income Tax Expense Component</u>

Minnesota Power will include a component of the revenue requirement calculation to recover the effective rate of taxes. This represents both current and deferred income taxes. The income tax amount will be based upon the Return on Equity component of the revenue requirement to equate it to a pretax amount.

<u>Interest Expense Component</u>

Minnesota Power will include a component of the revenue requirement calculation to recover the amount of interest expense that is incurred given the investment in the Transmission Projects. The interest component will be calculated based on the average monthly CWIP balance times the debt rate approved in the last rate case times the debt percentage of the allowed capital structure from the last rate case.

xi. Property Taxes – CWIP

Property taxes that Minnesota Power is required to pay on CWIP that is in-place are included in the project revenue requirements.

xii. Full Revenue Requirements – In-service

The in-service revenue requirements are calculated using the adjusted average monthly rate base for the Transmission Projects plus related expenses. The components of the revenue requirement include an after-tax return on investment, current and deferred income taxes, interest expense, depreciation expense, property taxes and other incremental O&M expenses related to the transmission projects.

xiii. Rate Calculation and Impact - Minn. Stat. § 216B.16, subd. 7b(c)(5)

Consistent with the terms in Minnesota Power's last approved transmission factor filing docket,[35] the Company calculated its 2025 Transmission Factor. Minnesota Power utilized the appropriate authorized rate of return and the jurisdictional Power Supply Transmission Demand allocators, based on those approved by the Commission in Minnesota Power's most recent rate case.[36]

1. Tracker Mechanism

In support of the Transmission Rider billing adjustment filings, Minnesota Power has implemented a tracker mechanism to account for the balance of actual revenue requirements and cash collected from customers. The trackers indicate the actual monthly Minnesota jurisdictional revenue requirements, actual cash collections, and over/under balances.

2. Deferred Taxes

Under Internal Revenue Code Section 167, rate-regulated utilities that utilize accelerated tax depreciation are required to use a normalization method of accounting. If a future test year, or a part historical and part future test year are utilized when determining the reserve for deferred taxes for the reduction of rate base, then a specific pro rata calculation must be utilized to avoid a normalization violation.

3. Customer Impact

Table 5 below summarizes the rate impacts by customer class compared to current rates. The current rates reflect the currently in effect 2024 TCR Factors. The information provided in Table 5 also reflects the final general base rates without riders in the Company's most recent

[35] Docket No. E-015/M-23-460.

[36] Docket No. E-015/GR-23-155.

completed rate case adjusted to include current rider rates.

Table 5 - Estimated Customer Impact[37]

Rate Class Impacts 1/	SES-Paying Customers	SES-Exempt Customers
Residential		
Average Rate (¢/kWh)	14.961	
Increase (¢/kWh)	0.110	
Increase (%)	0.74%	
Average Impact ($/month)	$0.76	
General Service		
Average Rate (¢/kWh)	15.005	14.899
Increase (¢/kWh)	0.110	0.110
Increase (%)	0.73%	0.74%
Average Impact ($/month)	$2.80	$12.45
Large Light & Power		
Average Rate (¢/kWh)	11.586	11.434
Increase (¢/kWh)	0.110	0.110
Increase (%)	0.95%	0.96%
Average Impact ($/month)	$254.98	$485.40
Large Power		
Average Rate (¢/kWh)		8.937
Increase (demand + energy combined) (¢/kWh)		0.137
Increase (%)		1.53%
Average Impact ($/month)		$67,829
Lighting		
Average Rate (¢/kWh)	45.778	
Increase (¢/kWh)	0.110	
Increase (%)	0.24%	
Average Impact ($/month)	$0.14	

Notes:
1/ Average class rates are draft Final General Rates without riders per MPUC October 24, 2024 decision (E015/GR-23-155) adjusted to include current rider rates. Current rider rates include the Transmission Cost Recovery Rider rates, Renewable Resources Rider rates, Solar Renewable adjustment rates, Conservation Program Adjustment rates, expected Capacity Revenue and Expense adjustment, Solar Energy adjustment, and 2025 Fuel and Purchased Energy Adjustment with True-Up. The average increase (¢/kWh) shown above is the incremental decrease of the proposed 2025 factors compared to the existing in-place 2024 TCR factors. Due to different Solar Renewable billing factors included in General Service, Large Light & Power average rates, both the SES-Paying and SES-Exempt Customers' impacts are shown here for clarity.

5. Conclusion

Minnesota Power requested approval of the Company's rate adjustment mechanism as proposed in the August Petition. The 2025 TCR Factor appropriately recovers the costs

[37] Xcel Petition; at 48.

associated with new transmission facilities that will efficiently provide customers and the Midwest region with clean, emission-free energy, and MISO new facility charges. Minnesota Power looks forward to working with regulators and its stakeholders in the timely approval of its annual rate adjustment mechanism.

B. Department of Commerce – Comments

On November 17, 2025, the Department filed its Comments to for Minnesota Power's Petition for approval of a Transmission Cost Recovery Rider.

The Department requested that Minnesota Power file additional information in Reply Comments to be reviewed before providing its recommendations.

The Department noted that MP's Petition requested approval of its forecasted 2025 annual revenue requirements, 2024 Tracker Balance, and resulting 2025 Transmission Factors under the TCR to recover certain Minnesota jurisdictional transmission costs.

The Department provided Table 6, a summary of the Company's 2025 MN Revenue Requirements.

Table 6: Summary of Proposed 2025 MN Revenue Requirements

Item	2025 MN Revenue Requirements
Tracker Balance as of Dec. 31, 2024	**$ 1,964,299**
Duluth Loop	**$ 3,676,303**
ID# 113305 Duluth Loop Reliability Project	720,808
ID# 113316 Ridgeview Sub - Duluth Loop	668,110
ID# 113317 Arrowhead Sub - Duluth Loop	523,217
ID# 113318 Hilltop Sub - Duluth Loop	1,366,559
ID# 113539 230kV Projects	399,496
Prorata ADIT[10]	(1,887)
HDVC Modernization	**$ 2,541,790**
ID# 113372 HVDC Modernization - ND	1,293,481
ID# 113373 HVDC Modernization - MN	912,133
ID# 114425 HTEC Project – MN	183,202
ID# 114426 HTEC Project – ND	149,308
Prorata ADIT[11]	3,665
Net RECB Revenue & Expenses	**$ 12,266,570**
Auction Revenue Rights (ARR) Credit	**$ (188,312)**
Total:	**$ 20,260,650**

The Department noted that MP seemed to have transposed its net RECB revenue and expenses figure of $12,266,570 in Exhibit B-2 to $12,266,750 in Table 7 of its Petition. The Department notes the correct figure is $12,266,570 and has reflected it here.[38]

1. Department's Analysis

Statutory Requirements

The Department noted that it searched statutes and Commission Orders to formulate its comments. The Department noted that Minnesota Legislation provides guidance for the recovery of construction costs in a Utility's TCR. The legislative guidance helps the Department verify various aspects of MP's TCR. Such guidance includes criteria on project eligibility, cost minimization of projects, and the parameters retrieved for the construction of costs proposed for recoupment.

Changes Between November of 2024 and August 2025 Petitions

MP's August 2025 Petition mirrors the November 2024 Petition, with the exception that no revenues or expenses associated with the Northland Reliability Project (NRP) and Alexandria – Big Oaks Project are included.[39] The Company's primary reason for excluding these two MISO Tranche 1 Long Range Transmission (LRTP) projects (currently MP's only LRTP projects) from the TCR is because they are more appropriately considered Federal Energy Regulatory Commission (FERC) jurisdictional projects rather than retail jurisdictional projects.[40]

Table 7 below summarizes MP's proposed changes by line item and related revenue requirements for the period.

Table 7: Minnesota Power's Change in Proposed 2025 MN Revenue Requirements

Item	Original 2025 MN Revenue Requirements		Refiled 2025 MN Revenue Requirements		Change	
Tracker Balance as of Dec. 31, 2024	$	1,974,535	$	1,964,299	$	(10,236)
Duluth Loop	$	3,676,303	$	3,676,303	$	-
HDVC Modernization	$	2,541,790	$	2,541,790	$	-
Alexandria - Big Oaks	$	649,507	$	-	$	(649,507)
Net RECB Revenue & Expenses	$	6,643,731	$	12,266,570	$	5,622,840
Auction Revenue Rights (ARR) Credit	$	(188,312)	$	(188,312)	$	-
Total:	**$**	**15,297,554**	**$**	**20,260,650**	**$**	**4,963,096**

As shown above, removing NRP and the Alexandria-Big Oaks Project increases the revenue requirement by approximately $5 million.

Even though the Petition increased the revenue requirement by $5 million, the Department

38 Department's Comments; at 3.

39 MP's Petition; at 4-5.

40 Id.

recognized that MP's proposal to exclude NRP and the Alexandria-Big Oaks Project mirrors Otter Tail Power Company's (Otter Tail or OTP) proposal made in its 2016 General Rate Case.[41] Otter Tail proposed a similar "all out" method where Big Stone Lines, a MISO transmission line, be excluded from OTP's TCR and recovery for this transmission line at a FERC jurisdictional level rather than at the retail level. Essentially, Otter Tail was proposing to keep the net MISO revenues including the FERC ROE which was higher than the Commission approved ROE. The Commission initially denied this proposal, which Otter Tail appealed. This case ultimately ended up at the Minnesota Supreme Court where it was determined that is up to the utility's discretion as to which projects are included in its TCR, and that investors in these types of projects are entitled to the FERC-allowed ROE.[42]

The Department asks MP to confirm in reply comments if its proposed "all out" method is comparable to the OTP Method and identify if there are any differences.

The Department noted that utilizing an "all out" method is cleaner when it comes to MISO projects. The Department asked MP to confirm in reply comments if Operating and Maintenance (O&M) expenses are tracked by each transmission line. The Department asked MP to confirm that the O&M expenses allocated to NRP and the Alexandria-Big Oaks Project will be excluded in future rate cases and any applicable riders. Finally, the Department asked MP to explain and identify in reply comments any related expenses, both direct and allocated, for the NRP and the Alexandria-Big Oaks Project that would not be excluded in future rate cases and riders, and explain why that exclusion would be reasonable.

Project Eligibility

The Department observed that an in-state transmission project is eligible for recovery under the TCR statute if the project is 1) approved under the certificate of need statute, 2) exempt from the certificate of need statute, 3) certified as or deemed to be a priority project under the state transmission plan, or 4) determined to benefit the utility or transmission system by the Midcontinent Independent System Operator (MISO).[43]

The Department affirmed that for the 2025 Rider, MP seeks approval to recover costs for three projects:

- Duluth Loop
- HVDC Modernization Project
- MISO Charges & Credits—This includes the Net RECB Revenue & Expenses, and the

[41] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, Otter Tail Power Company, February 16, 2016, Docket No. E-017/GR-15-1033 (eDockets), hereinafter "OTP Method."

[42] In re the Appl. of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., 942 N.W.2d 175, 181 (Minn. 2020).

[43] See 2025 Minn. Stat. § 216B.16, subd. 7b, 216B.243 and 216B.2425.

> Auction Revenue Rights (ARR) Credit in the Revenue Requirements.

Based upon Statutory guidance and Orders for approval by the Commission, the Department recommended that the above projects be included in MP's 2025 TCR.[44] Given the pool of eligible projects, the Department reviewed MP's estimated project costs in accordance with statute and Commission Orders.

TCR Project Costs

The Commission set a standard for evaluating TCR project costs going forward in Xcel Energy's TCR filing in Docket No. 09-1048.[45] The Commission stated as follow in its April 7, 2010, Order for the assignment of project costs:

> […] the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

The Commission applied this same approach to Otter Tail Power Company in its 2013 TCR in Docket No. 13-103.[46] In its March 10, 2014, Order, the Commission stated:

> Accordingly, the Commission continues to believe that project costs included in the TCR rider should be capped at certificate of need levels. […] [I]mposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. And capping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders. […]
>
> In the absence of a rate case, the best available proxy for determining prudence and reasonableness is the cost determination made on the record of a certificate

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[44] Order Granting Certificate of Need and Issuing Route Permit, April 3, 2023, Docket No. E-015/CN-21-140 (eDockets) 20234-194456-02, at 12; Order Granting Certificate of Need and Issuing Route Permit, October 25, 2024, Docket No. E- 015/CN-22-607, (eDockets) 202410-211332-01, at 22; and In the Matter of Minnesota Power's Request for Approval of its 2022 Transmission Factors under its Transmission Cost Recovery Rider, Minnesota Department of Commerce, Comments, May 23, 2022, Docket No. E-015/M-21-857, (eDockets) 20225-185991-01, at 8.

[45] Order Approving 2010 TCR Project Eligibility and Rider, 2009 TCR Tracker Report, and TCR Rate Factors, April 27, 2010, Docket No. E-002/M-09-1048, (eDockets) 20104-49616-01, at 6; Order Granting Certificate of Need and Issuing Route Permit, October 30, 2024, Docket No. E-002, E-017, ET2, E-015, ET10/CN-22-538, (eDockets) 202410-211465-02, at 6.

[46] Department's Comments; at 9.

> of need or cost recovery eligibility proceeding. Here, the relevant proceeding is a certificate of need case. Otter Tail should continue recovering the costs it sponsored in its certificate of need case unless and until it demonstrates in a rate case that higher costs are prudent and reasonable. [Footnotes omitted.]

d.1. Duluth Loop

In its Certificate of Need and Route Permit Application approved by the Commission, MP estimated the capital cost range of the Project between $50 million and $70 million (in 2021 dollars).[47]

In the instant petition, the Department noted that MP's proposed 2025 revenue requirements for the Duluth Loop are based on net plant costs of approximately $35 million and construction work in progress (CWIP) costs of approximately $22 million, for a total of approximately $57 million through 2025. Thus, the Department concluded the Company's current Duluth Loop capital project costs are under the capital cost range established in the Certificate of Need and Route Permit proceeding.

MP's in-service date is currently December 2026. Originally, at the time of MP's initial filing, the in-service date was in December 2025. The one-year difference between schedules appears to be due to a longer construction period. The starting dates for construction are the same: September 2023. However, MP noted supply chain issues, and perhaps other delays, in acquiring a wetland permit.[48]

The Department noted that MP did recognize supply chain issues in its last Petition. The Department noted further that MP was aware of potential supply chain risks, along with trending labor costs. MP did not say how it plans to mitigate the supply disruption in the Petition.

d.1.1 Impact of Project Delays

In the Department's February Comments, a request was made for more information about the cost impacts from the delays. The Department also requested information about any other delays since the approval of the 2021 Duluth Loop Certificate of Need, a requested descriptions on a series of issues.[49]

MP addressed the requests in its February Reply Comments and confirmed no changes in

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[47] Order Granting Certificate of Need and Issuing Route Permit, Public Utility Commission, April 3, 2023, Docket No. E- 015/CN- (eDockets) 20234-194456-02, at 12. The cost estimates can be found in Findings of Fact, Conclusions of Law, and Recommendation, Office of Administrative Hearings, December 15, 2022, Docket No. E-015/CN-21-140 (eDockets) 202212- 191387-01, at 6 and 83.

[48] MP Petition; at 25.

[49] *Id*; at 11.

Department Information Request #5. Responses are summarized below.

> Regarding supply chain delays, irregularities first started during the COVID-19 pandemic and the Company is facing ongoing variable lead times for common transmission line materials. MP has been able to order certain materials proactively. MP typically acquires basic materials through standard suppliers, however when standard suppliers are not able to meet required lead times, alternative suppliers and manufactures are considered. The Company has also been able to utilize materials ordered and received for other projects that had not commenced construction or were otherwise delayed. This has allowed overhead line construction to begin in July 2025 as planned. MP noted that there are no discrete costs within the 2025 TCR that are attributed to material lead time delays and there is no specific project cost increases due to increased labor costs.
>
> The US Army Corps of Engineers Section 404 wetland permit application was submitted in October of 2023. MP received the wetland permit on January 16, 2025. Though the permitting process took longer than expected, due to other factors preventing transmission line work such as habitat protection of northern long-eared bats and Commission approval of transmission lines, the permit only delayed work by one month. There are no significant costs associated with the delay of the wetland permit.[50]

The Department asked if there any other delays that contributed to the one-year delay, MP stated the following:

> The Company is not aware of any other externalities impacting schedule at this time. However, there may be market forces that impact future materials availability and pricing including tariffs and/or a market-wide shift to domestic production that constraints limited production resources.
>
> Minnesota Power's Supply Chain staff continues to monitor the current regulatory environment and has reached out to key vendors to confirm production locations and identify alternatives.[51]

The Department recognized that MP may not be able to identify every risk that may lead to a delay. The Department appreciated the explanation of the conditions that may lead to a delay and what risk mitigation efforts are being implemented by MP.

d.2 HVDC Modernization

MP discussed its cost estimates for the HVDC Modernization project. The Department verified

[50] Department's Comments; atg 12.

[51] February Reply Comments at 7.

that the $660-$940 million is the same as authorized by the Commission in MP's Certificate of Need.[52]

The Department noted that that MP's proposed 2025 revenue requirements for the HVDC Modernization project are based on CWIP costs of approximately $31 million.[53] Thus, the Department concluded the Company's HVDC Modernization capital project costs are under the initial cost estimates established in the Certificate of Need proceeding.

MP is completing the permitting process and construction began in May 2025. The project implementation date is now scheduled for December 2030. The Company's implementation date was initially scheduled for December 2028, however, when MP reached out to its preferred supplier, the earliest implementation date for the equipment used in the HVDC terminals that MP could secure was April 2030.

D.3. MISO Transmission Projects

The Department noted that during the 2008 Minnesota Legislative Session, Minn. Stat. § 216B.16, subd. 7 was amended to allow utilities providing transmission service to recover the charges incurred by a utility "that accrue from other transmission owners' regionally planned transmission projects that have been determined by MISO to benefit the utility," as provided for under a "federally approved tariff," upon Commission approval. The Statute further requires any recovery to "be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

The Commission directed the Company to "provide supporting documentation to substantiate the actual RECB charges incurred during the upcoming year as part of future Rider Filings in its June 23, 2009 Order."[54] In its Petition, MP proposed to include net RECB charges (MISO Schedules 26/26A, 37 and 38) totaling $14,851,828 on a Total Company basis and $12,266,570 on a Minnesota Jurisdictional basis in its TCR for cost recovery.[55] The Company provided a detailed calculation of its RECB revenues and expenses by MISO schedule in Exhibit B-2 of the Petition.

The Department reviewed MP's calculations and proposal to recover its net RECB charges in the

[52] In the Matter of the Application of Minnesota Power for a Certificate of Need for the HVDC Modernization Project in Hermantown, Saint Louis County, Office of Administrative Hearings, June 21, 2024, Docket No. E-015/CN-22-607, (eDockets) 20246-207868-02, at 32, 138-140. See Also, Order granting certificate of need and issuing route permit, March 5, 2024, Docket No. E-015/CN-22-607, (eDockets) 202410-211332-01, at 22-23.

[53] MP's Petition, Exhibit B-4 at 2.

[54] In the Matter of Minnesota Power's Request for Approval of its 2009 Rate Adjustment Mechanism under its Transmission Cost Recovery Rider, Order Approving Transmission Factors with Conditions, June 23, 2009, Docket No. E-015/M-08-1176, (eDockets) 20096-38819-01, at 4.

[55] Petition at Exhibit B-2, at 4.

TCR and concluded that the Company's calculation is reasonable.

Net Regional Expansion and Cost Benefit (RECB) Charges (MISO SCHEDULES 26/26A, 37 & 38)

RECB charges and revenues are generally reflected under MISO Schedules 26/26A. MISO Schedule 26 includes other regionally shared projects such as Market Efficiency Projects and Generation Interconnection Projects. MISO Schedule 26A includes projects deemed as Multi-Value Projects (MVPs).

In its June 23, 2009 Order in Docket No. E-015/M-08-1176, the Commission directed the Company to "provide supporting documentation to substantiate the actual RECB charges incurred during the upcoming year as part of future Rider filings." MP provided the required documentation in Exhibit C-1 of its petition.

As shown in Exhibit B-2, Page 4 of its petition, MP proposed to include net RECB charges (MISO Schedules 26/26A, 37 and 38) totaling $12,266,570 in its TCR revenue requirements. The Company provided a detailed calculation of its RECB revenues and expenses by MISO schedule in Exhibit B-2 of the petition.

The Department reviewed and concurred with MP's calculation and proposal to recover its net RECB charges in the current petition.

MVP Auction Revenue Rights (ARR)

MISO Auction Revenue Rights (ARR) revenues are MP's entitlement to a share of revenue generated in annual Financial Transmission Rights (FTR) auctions.[56] MP stated that its historical usage of MISO's transmission system determines its share and, depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge.

The Department reviewed MP's proposed treatment of MVP ARR revenues and agrees with its approach.

Tracker Balance

As shown in Exhibit B-1, MP proposed to recover its 2024 tracker balance of $1,964,299 to reflect prior under-recoveries.[57] MP's tracker balance calculations are shown in Exhibit B-2. In addition, MP's current Petition notes that the tracker balance for Large Power Class is $616,337 and that the balance for all other classes is $1.3 million.

The Department reviewed MP's tracker calculations as shown in Petition Exhibit B-2 and

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[56] MP's Petition; at 4.

[57] MP's Petition at B-1, at 1.

recommended the Commission approve MP's 2025 tracker balance for recovery.

Other Wholesale Transmission Revenues (Non-RECB)

The Department has noted in the past that the bulk of Minnesota regulated electric utilities' transmission assets over 100 kilovolts are non-RECB projects for MISO purposes and are included in the utilities' base rates rather than in a transmission rider.[58] As such, any wholesale transmission revenues and expenses (MISO Schedule 9 revenues and expenses) associated with these facilities are now generally reflected in base rates.

In addition to the wholesale transmission revenues and expenses through MISO Schedules 26/26A for RECB projects as discussed above, some utilities receive other wholesale transmission revenues from third-party transmission customers who are charged the utility's Federal Energy Regulatory Commission (FERC) jurisdictional MISO tariff rate for the use of the utility's non-RECB transmission system.

Similar to RECB charges reflected in MISO Schedules 26/26A, the Department noted that these non-RECB charges are reflected in MISO Schedule 9 revenues for the party that owns the transmission assets and in MISO Schedule 9 expenses for any party that uses the transmission assets (including the assets' owner).

As stated prior, some utilities have provided a net credit[59] in their TCR Rider to account for revenues it expects to receive from MISO for other utilities' use of the transmission asset. This net credit reflects the difference between what the utility pays MISO for using its own non-RECB transmission asset and what the utility receives from MISO for other utilities' use of the asset.

The Department acknowledged that both the Duluth Loop and HVDC Modernization projects are considered to be non-RECB projects for MISO purposes. The Department recommended that MP provide in reply comments any net credits that it receives from MISO under Schedule 9 for other utilities use in 2025.

Internal Capitalized Costs

In a transmission factor proceeding in Docket No. E-015/M-11-695, the Commission determined MP's internal capitalized costs should be excluded from recovery under the Company's TCR Rider. As explained in MP's Petition, the Company complied with the Commission's directive

[58] Petition at 23 and 38, In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider under Minn. Stat. § 216B.16, subd. 7b, Minnesota Power, October 24, 2023, Docket No. E-015/M-23-460 (eDockets) 202310-199855-01, at 11

[59] As opposed to MISO Schedules 26/26A revenues and expenses which are reflected at gross in Minnesota rate-regulated utilities TCR Riders. The gross and net methods produce the same results. However, the Department generally prefers the gross method since it reflects all the MISO revenues and expenses associated with a specific project.

and excluded internal capitalized costs.[60]

The Department reviewed MP's proposed accounting for internal capitalized costs and concludes the Company complied with the Commission's directive.

Rate of Return on Investment

Minn. Stat. § 216B.16, subd. 7b (2025) allows utilities to charge ratepayers a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest. MP proposed to use its equity and debt components approved in its last retail rate case (Docket No. E-015/GR-23-155) to calculate its return on investment in this proceeding. The Department did not object.

Allocation

Minn. Stat. § 216B.16, subd 7b (2025) requires utilities to allocate project costs appropriately between wholesale and retail customers. MP proposed to use the jurisdictional demand allocators the Commission approved in its 2021 retail rate case (Docket No. E-015/GR-21-335), to allocate costs between wholesale operations (MP's municipal and cooperative customers) and retail operations for 2023. Additionally, MP proposed to use the jurisdictional demand allocators the Commission approved in its 2024 retail rate case (Docket No. E-015/GR-23-155) to allocate costs between wholesale operations and retail operations for 2024 and 2025.

Given that MP's proposal is consistent with the Commission's prior allocation determinations, the Department agreed with this approach.

Prorated Accumulated Deferred Income Taxes

MP proposed that its 2025 Transmission Factors take effect on the first of the month following Commission approval.[61] For tax purposes, 2025 is considered a future year, therefore MP must use the pro rata calculation. The calculation helps avoid a violation to the normalization for the allocation factors, which is required by the IRS when taking accelerated depreciation.

Based on its review, the Department recommended approval of MP's pro rata method.

Potentially Eligible Projects

The Commission's Ordering Paragraph 7 from the December 3, 2020, Order Approving Transmission Cost Recovery, Clarifying Prior Order, and Requiring Filings requires MP to include descriptions of all potentially eligible TCR projects.[62] The Company is required to list the projects it will seek recovery of in the future, and the impacts those projects will have on the

[60] MP's Petition; at 13 and in Exhibit B-4.

[61] MP's Petition, at 10.

[62] MP's Petition at 9.

Transmission Cost Recovery Factor.

MP stated in the current Petition that “there are currently no potential eligible projects to include.”[63] MP does identify two projects assigned to the FERC jurisdiction for which MP will not be seeking recovery through the TCR. The Company plans to take part in the Northland Reliability Project and the Eastern Segment of the Big Stone South – Alexandria – Big Oaks 345 kV Transmission Line Project.

Based on the above, the Department concluded MP complied with Ordering Paragraph7 of the Commission’s December 3, 2020, Order.

Rate Design

The TCR is applicable to electric service under all of MP’s Retail Rate Schedules, including Large Power, except its Competitive Rate Schedules 73 and 79. In addition, it applies to service under the Large Power Interruptible and Large Power Incremental Production Service riders. MP proposed to allocate the retail revenue requirement Transmission Demand jurisdictional and class allocators reflecting the outcomes of the Company’s 2021 and 2024 rate cases.

This is the same method used to allocate costs within the Large Power class in MP’s previous TCR filings.[64] The Department agreed with this approach.

Bill Impact and Tariff Review

As stated above, MP proposed its 2025 Transmission Factors take effect on the first of the month following Commission approval. Table 8 below summarizes the bill impact of Minnesota Power’s proposal.

Table 8: Minnesota Power’s Proposed Bill Impact[66]

	Current Rate	Proposed Rate	Increase
Large Power ($/kW per month)	0.36	0.83	0.47
Large Power ($/kWh)	0.047	0.117	0.070
All Other Classes ($/kWh)	0.195	0.305	0.110

2. Department Recommendations

Based on analysis of the Petition, the Department has prepared the following requests:

- The Department asks MP to confirm in reply comments if its proposed “all out” method

[63] Id.

[64] In the Matter of Minnesota Power’s Request for Approval of its 2022 Transmission Factors under its Transmission Cost Recovery Rider, Minnesota Department of Commerce, Comments, May 23, 2022, Docket No. E-015/M-21-857, (eDockets) 20225-185991-01, at 15.

is comparative to the OTP Method and identify if there are any differences.

- The Department asks MP to confirm in reply comments if O&M expenses are tracked by each transmission line.

- The Department asks MP to confirm in reply comments that the O&M expenses allocated to NRP and the Alexandria-Big Oaks Project will be excluded in future rate cases and any applicable riders.

- The Department asks MP to explain and identify in reply comments any related expenses both direct and allocated for the NRP and the Alexandria-Big Oaks Project that would not be excluded in future rate cases and riders, and explain why that is reasonable.

- The Department asks MP to provide in reply comments any net credits that it received from MISO for other utilities use of the Duluth Loop and HVDC Modernization projects in 2025.

C. Large Power Intervenors – Reply Comments

The Large Power Intervenors (LPI) filed its Comments on December 1, 2025, and requested that MP supplement the record in the docket with information on rate-impact projections to resolve inconsistencies in the information provided.

LPI noted that MP filed petitions in three dockets that will impact rates for its customers: its Integrated Resource Plan (IRP) (Docket No. E-015/RP-25-127), its Renewable Resource Rider (RRR) (Docket No. E-015/M-25-373), and its Transmission Cost Recovery (TCR) Rider (Docket No. E-015/24-382). LPI stated that in each docket, MP projected that certain capital investments will necessitate rate increases to recover costs either through base rates or riders. LPI expressed concern that there are inconsistences on cost impact projections between the IRP, RRR, and TCR, as to the current and forecasted average cost of electric energy.

On review of the cost estimates for ratepayers provided in each docket, LPI stated that it observed a couple material discrepancies that require clarification, and which would be best addressed by MP in reply comments in the TCR Rider and RRR dockets and its Clean Firm Plan filing in the IRP docket.

1. MP Provides Inconsistent Cost Impact Estimates in its IRP and Rider Petitions

a. Docket No. 25-373 – Renewable Resource Rider

LPI noted that On October 1, 2025, MP filed its petition to update its RRR (RRR Petition). MP's RRR enables recovery of investments and expenditures incurred for approved renewable resource projects. In its 2026 RRR petition, MP requested Commission approval to update its cost recovery through the RRR to: (1) include the annual true-up of actual production tax credits; (2) recover costs related to its Boswell Solar Project and the Boswell Interconnector; and (3) recover costs related to its Regal Solar Project, for a total requested recoverable Net Retail revenue requirement for the 2026 Renewable Resources Rider of $54.1 million (consisting of the 2025 projected tracker balance of $11.3 million and the projected 2026 revenue requirements of $42.8 million).[65]

Table 9 below which is Table 7 from the RRR Petition, sets for the present average rate and increases for the various customer classes, including Large Power (LP) and Large Light and Power (LLP). Both LLP and LP customers will see an increase of 5.03% and 5.60%, respectively.

Table 9– Estimated Customer Impact (MP RRR Petition).

Table 7 - Estimated Customer Impact

Rate Class Impacts /1	SES-Paying Customers	SES-Exempt Customers /3
Residential (average current rate, cents/kWh)	15.196	
Increase/(Decrease) (cents/kWh) /2	0.585	
Increase/(Decrease) (%)	3.85%	
Average Impact ($ / month)	$4.02	
General Service (average current rate, cents/kWh)	15.114	15.054
Increase/(Decrease) (cents/kWh) /2	0.585	0.585
Increase/(Decrease) (%)	3.87%	3.89%
Average Impact ($ / month)	$14.77	$46.55
Large Light & Power (average current rate, cents/kWh)	11.642	11.593
Increase/(Decrease) (cents/kWh) /2	0.585	0.585
Increase/(Decrease) (%)	5.03%	5.05%
Average Impact ($ / month)	$1,367	$2,119
Large Power (average current rate, cents/kWh)		8.970
Increase (Demand & Energy Combined) (cents/kWh) /2		0.503
Increase/(Decrease) (%)		5.60%
Average Impact ($ / month)		$217,352
Lighting (average current rate, cents/kWh)	45.739	
Increase/(Decrease) (cents/kWh) /2	0.585	
Increase/(Decrease) (%)	1.28%	
Average Impact ($ / month)	$0.76	

Notes:

1/ Average current rates are 2024 Final General base rates without riders per MPUC decision (E-015/GR-23-155) adjusted to include current rider rates. Current rider rates included Renewable Resources Rider rates, Solar Adjustment rates, Conservation Program Adjustment rates, and Fuel and Purchased Energy with True-Up. RRR Cost Recovery rates are new expected 2026 rates. Average $/month impact based on 2026

2/ Increase shown is the rate increase of propopsed 2026 RRR Factors compared to existing in-place 2024 RRR Factors.

3/ Due to different Solar Renewable billing factors included in General Service and Large Light & Power current average rates, both of the SES-Paying and SES-Exempt impacts are shown here for clarity.

65 RRR Initial Petition at 21.

b. Docket No. 24-382 – TCR Rider

On August 19, 2025, the Company filed its Petition to update its TCR Rider (TCR Petition).

MP's 2025 TCR Petition seeks recovery of: (1) costs related to its High Voltage Direct Current (HVDC) Modernization Project; (2) "costs net of revenues of transmission facilities that the Commission has approved under section 216B.243 or has certified or deemed to be certified under section 216B.2425;" and (3) charges incurred under the Midcontinent Independent System Operator tariff for other transmission owners' regionally planned transmission facilities that will benefit the Company and the integrated transmission system.[66]

MP estimated the 2025 TCR factors it proposes will increase an average of about 93 percent from the 2024 TCR Factors. The table below, which is Table 8 from the TCR Petition, sets forth the present average rate and increases for the various customer classes, including LLP and LP customers. LLP customers are projected to experience a roughly 1.0% increase and LP customers will see an increase exceeding 1.5%.

c. Docket No. 25-127 – MP IRP Filing

Finally, MP's IRP Petition provides an estimated cost impact across rate classes in its Appendix L (see the table below, which is Table 1 of Appendix L to the IRP). Table 11 reports for 2026, LLP and LP customers will experience increases of roughly 1.8%, which is less than half of the projected increase for the RRR alone.

Table 11 – Estimated Average Rate Impacts of 2025 (MP IRP Appendix L)

[66] TCR Petition at 3-4. This (3) charge includes: "new transmission facilities approved by the regulatory commission of the state in which the facilities are being constructed that MISO has determined to benefit Minnesota Power or the integrated transmission system." TCR Petition at 4.

Rate Class Impacts[9]	2026	2027	2028	2029	2026 – 2029 CAGR
Residential (average rate, cents/kWh)	14.961	14.961	14.961	14.961	
Increase (cents/kWh)	0.277	1.058	1.839	1.472	
Increase (%)	1.85%	7.07%	12.29%	9.84%	2.37%
Average Impact ($ / month)	$1.90	$7.24	$12.64	$10.10	
General Service (average rate, cents/kWh)	15.005	15.005	15.005	15.005	
Increase (cents/kWh)	0.278	1.060	1.844	1.475	
Increase (%)	1.85%	7.07%	12.29%	9.83%	2.37%
Average Impact ($ / month)	$6.95	$26.41	$45.97	$36.40	
Large Light & Power (average rate, cents/kWh)	11.584	11.584	11.584	11.584	
Increase (cents/kWh)	0.218	0.823	1.429	1.146	
Increase (%)	1.88%	7.11%	12.33%	9.89%	2.39%
Average Impact ($ / month)	$437.78	$1,616.59	$2,756.65	$2,147.10	
Large Power (average rate, cents/kWh)	8.937	8.937	8.937	8.937	
Increase (cents/kWh)	0.160	0.634	1.109	0.885	
Increase (%)	1.80%	7.09%	12.41%	9.90%	2.39%
Average Impact ($ / month)	$94,071	$371,582	$600,104	$489,207	
Lighting (average rate, cents/kWh)	45.778	45.778	45.778	45.778	
Increase (cents/kWh)	0.779	3.034	5.388	4.362	
Increase (%)	1.70%	6.63%	11.77%	9.53%	2.30%
Average Impact ($ / month)	$1.08	$4.19	$7.43	$5.97	
Average Weighted Increase (cents/kWh)	0.192	0.746	1.298	1.035	
Avg Weighted Increase (%)	1.82%	7.09%	12.33%	9.82%	2.37%

2. The Discrepancy in Estimates Across Filings is Significant and Needs Correction

Appendix L to MP's initial IRP Filing asserts that it provides estimated rate impacts of MP's power supply plan for the next five years, which it refers to as the "5 Year Power Supply Plan."[67] According to MP, the 5 Year Power Supply Plan includes "actions from the prior approved IRPs and the recommended plan in the 2025 IRP." MP stated that it calculated the estimated rate impacts by customer class relative to its 2025 Base Rates, which use MP's 2024 test year rate as a starting point. The 2024 test year base rates include the estimated average rates customers will pay in 2025 for Minnesota Power's RRR, TCR Rider, and the Capacity Revenue and Expense Adjustment.

LPI asserted that MP's cost estimates across all three dockets inform each other and are intertwined, such that discrepancies across the estimates may impact and obfuscate the actual cost implications for customers. LPI stated that across all three filings, it observed

[67] MP IRP Appendix L at 1.

inconsistencies in the reported rate increases for Large Power customers, both with respect to the starting point and with respect to the projections.[68]

a. MP Appears to be Understating the Current Rate

MP asserted that the average current rate for LP customers is $89.37/MWh in the IRP and TCR Petition, but asserted it is $89.70/MWh in the RRR Petition.[69] Similarly, MP asserts that the average current rate for LLP customers is $115.84/MWh in the IRP, and ranging from $114.34-115.86/MWh in the TCR Petition and ranging from $115.93-$116.42/MWh in the RRR Petition.[70] According to LPI, these inconsistencies in starting points for the year 2026 are even more concerning given Minnesota Power's interim-rate refund compliance filing that it submitted on December 20, 2024, in MP's most recent rate case docket. According to LPI, the Company projected that, from the Commission's decision, all-in rates with riders would be $104.82/MWh for LP customers and $120.73/MWh for LLP customers.[71] LPI contended that both of these figures as of MP's rate case compliance filing are dramatically below what MP has put in the IRP, TCR Petition and RRR Petition. LPI respectfully asserts this discrepancy needs clarification.

b. MP Appears to be Understating Rate Projections

LPI stated that in addition to the inconsistent starting point for current rates, it cannot reconcile the increases projected in MP's IRP with the information contained in the TCR Petition and RRR Petition. For example, LPI failed to understand how LLP and LP customers will experience increases of roughly 1.8% in 2026 according to the IRP, while at the same time see increases from 6% to 7% in just the TCR and RRR dockets. LPI asserted this discrepancy also requires clarification.

c. Conclusion

For the reasons LPI described above, LPI requested the Company undertake the following work to resolve the discrepancies identified above:

Update its cost impact projections in its reply comments in the TCR Rider and RRR dockets.

- Updated table (i.e., Table 1 from Appendix L to the IRP) in its Clean Firm plan filing in the pending IRP docket with the following information:
    - A current and accurate starting point for 2026 average rates for each of the customer classes; and

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[68] LPI Comments; at 9.

[69] See Tables 1, 2, and 3, supra notes 10, 15, 17.

[70] See Tables 1, 2, and 3, supra notes 10, 15, 17.

[71] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-015/GR-23-155, Compliance Filing, Schedule 11 at 6 (December 20, 2024) ($137,575,110/1,139,554 MWh = $120.73/MWh).

- A current and accurate projection of all-in rate increases each customer class is projected to experience over the 2026-2029 timeframe.

LPI stated that it believes this information is critical so that all stakeholders may understand and analyze the rate implications of MP's multiple proposals and assist the Commission's decision-making process. As such, LPI requested MP address these discrepancies in its reply comment in the RRR and TCR Rider dockets and provide corrected information in its "Clean Firm Plan" filing in the IRP.

D. Minnesota Power – Reply Comments

Minnesota Power filed its Reply Comments December 11, 2025. The Company responded to the Comments of the Department and LPI as follows:

1. Response to Department Requests

a. **The Department requested that Minnesota Power confirm if its proposed "all out" method is comparative to the OTP Method and identify if there are any differences***.*

MP stated that the Company's proposed "all out" method is comparative to the OTP Method.

b. The Department requested that Minnesota Power confirm if operations and maintenance (O&M) expenses are tracked by each transmission line.

Minnesota Power does track O&M expenses to site specific transmission lines.

c. The Department requested that Minnesota Power confirm that the O&M expenses allocated to NRP and the Alexandria-Big Oaks Project will be excluded in future rate cases and any applicable riders.

MP confirmed that all O&M expenses for NRP and Alexandria-Big Oaks Project will be excluded in future rate cases and future TCR Riders.

d. The Department requested that Minnesota Power explain and identify any related expenses both direct and allocated for the NRP and the Alexandria-Big Oaks Project that would not be excluded in future rate cases and riders, and explain why that is reasonable.

All direct and indirect (allocated) expenses related to the NRP and the Alexandria-Big Oaks Project will be excluded from the Minnesota jurisdiction in future rate cases and all direct expenses will be excluded from future TCR Riders.

e. The Department requested that Minnesota Power provide any net credits that it received from the MISO for other utilities use of the Duluth Loop and HVDC Modernization projects

in 2025.

The Duluth Loop Project is located entirely within the Minnesota Power local balancing authority area and it is a baseline reliability project that does not qualify for cost allocation under the MISO Tariff. Therefore, the Company has not received any direct net credits from MISO for other utilities use of the Duluth Loop project facilities. The HVDC Modernization Project is not projected to be in service until late 2028, at the earliest; therefore, no net credits have been received.

2. Response to LPI Requests

Minnesota Power addressed LPI's concerns below and explains why the current and forecasted cost projections in these three dockets have been calculated appropriately.

a. Current average cost of electric energy

MP stated that contrary to LPI's claims, there are no inconsistencies or discrepancies across the three dockets in the Company's calculations of current average cost of energy. The rate impact calculations follow the same consistent approach the Company has used for years in its TCR and RRR riders and IRP filings. As the Company has explained in each of its dockets over the years, the average current rates used in the rate impact calculations are updated with the latest available rider rates at the time the filing is being prepared. This provides customers with most up-to-date information available to understand rate impacts of proposed bill factors or projections. Therefore, it is expected that average current rates will be different for filings that are filed at different times.

The average current rates in both the 2025 IRP and 2025 TCR are based on the same data. Both were prepared using current rider rates from the fall of 2024 when the filings were being prepared. The only difference between the two is the way the General Service and Large Light & Power current average rates are displayed.

In the 2025 IRP blended or weighted rates were used for these classes to simplify the presentation for the IRP. The rates were blended as follows using the same exempt and non-exempt current average rates as in the 2025 TCR.

Figure 4: IRP weighted rates for General Service and Large Light & Power

General Service				
	kWh	Weighting %	Weighted c/kWh	Weighted Rate
Total	669,891,000			
Exempt	3,260,904	0.005	14.899	0.07
Non-Exempt	666,630,096	0.995	15.005	14.93
				15.005
Large Light & Power				
	kWh	Weighting %	Weighted c/kWh	Weighted Rate
Total	1,268,993,000			
Exempt	15,885,848	0.013	11.434	0.143
Non-Exempt	1,253,107,152	0.987	11.586	11.441
				11.584

LPI pointed out the Large Power average current rate in the subsequent 2026 RRR is 8.970 cents/kWh. This is a difference of 0.033 cents/kWh, or about 0.37 percent. The difference is attributable to the fact that the 2026 RRR was prepared in the summer of 2025 and used recently updated rider rates. The rider rates that were updated included the RRR Solar Factor (March 2025), Fuel and Purchased Energy Charge with True-Up (March 2025), Capacity Expenses and Revenue Adjustment (June 2025), and, although not applicable to Large Power, the Conservation Program Adjustment (March 2025).

LPI expressed concern when comparing the average current rates including riders in the 2025 TCR, 2026 RRR and the 2025 IRP, with the average rates with riders in the Company's Compliance Filing in its 2023 rate case. Because rider rates are not typically updated in rate case exhibits and E-Schedules during the course of a rate case, the rider rates included in LPI's rate comparison from the Company's Compliance Filing are no longer current and not comparable to the more recently updated rider rates in the three other dockets.

b. Forecasted cost of electric energy

LPI expressed concern that Minnesota Power provided inconsistent cost impact estimates in the three dockets and indicated that the Company appears to be understating the rate projections in the IRP. LPI compares the estimated 1.80 percent increase in the Large Power class for 2026 in the IRP projections with the 1.53 percent increase in the 2025 TCR and the 5.60 percent increase in the 2026 RRR. As with the average current rates above, LPI is making comparisons that are not valid. The estimated increases in the three dockets are mutually exclusive and are for different purposes.

The IRP rate impact from Appendix L is based on incremental power supply costs associated with anticipated future resources that will be required to meet Minnesota Power's power supply needs. The incremental costs are defined relative to the base year and represent the additional expenditure required to implement the 2025 IRP Base Plan. By definition, this rate impact is not comparable to the rate impacts in the cost recovery riders.

Minnesota Power has appropriately calculated the current average rates and rate projections in the 2025 IRP, 2025 TCR and 2026 RRR. Therefore, there is no need to provide the updates requested by the LPI in this Docket.

3. Conclusion

The 2025 TCR Factor appropriately recovers the costs associated with new transmission facilities and expenses for the NRP and the Alexandria-Big Oaks Project are being treated appropriately. The Company looks forward to the Department's final recommendations and a subsequent hearing for this Docket.

E. Department – Response to Reply Comments

On December 19, 2025, the Department filed its Response to MP's Reply Comments. The Department recommended the Commission approve MP's Petition.

1. **"All Out" Method**

After review of MP's response about its "all out" method, that it is comparative to OTP's method and no differences were identified, the Department found MP's proposal reasonable.

2. **MP to confirm if its operating and maintenance (O&M) expenses are tracked by each transmission line**.

After its review, the Department acknowledged MP's tracking of O&M expenses by specific transmission lines. The Department noted that this will allow the Company to properly allocate O&M expenses for future rate cases and riders.

3. **MP to confirm that the O&M expenses allocated to the Northland Reliability Project (NRP) and the Alexandria-Big Oaks Project will be excluded in future rate cases and any applicable riders.**

After review, the Department acknowledged MP's diligence to exclude O&M expenses for NRP and the Alexandria-Big Oaks Project in future rate cases and riders.

4. **MP asked to explain and identify any related expenses both direct and allocated for the NRP and the Alexandria-Big Oaks Project that would not be excluded in future rate cases and riders and explain why that is reasonable**.

After review, the Department noted MP's diligence to exclude all direct and indirect expenses for NRP and the Alexandria-Big Oaks Project in future rate cases and riders.

5. **MP requested to provide any net credits that it received from MISO for other utilities use of the Duluth Loop and HVDC Modernization projects in 2025.**

The Department acknowledged MP's explanation of the MISO Tariff for the Duluth Loop Project. Department recommended the Commission require MP to report in future TCR riders any net credits it received from MISO for other utilities use of the HVDC Modernization project once it is in service, as well as any other applicable future projects.

1. Conclusion

Based on its review and analysis of the information in the record, the Department recommended as follows:

- The Department recommends the Commission approve MP's Petition.
- The Department recommends the Commission approve MP's proposed tariff revisions.
- The Department recommends the Commission require MP to report in future TCR riders any net credits it received from MISO for other utilities use of the HVDC Modernization project once it is in service, as well as any other applicable future projects.

F. Staff Comments

Staff note that MP provided responses to the requests filed by the Department and LPI. Upon its review of the responses, the Department concluded that MP's responses were reasonable. Consequently, the Department recommended approval of the Company's Petition Staff also observed that MP provided reasonable and adequate responses to the Department's requests. As a result, staff concurs with the Department that MP's Petition be approved. LPI did not file any response to MP's Reply Comments.

G. Decision Options

1. Approve MP's Petition, including the Company's proposed tariff revisions. (MP, Department)

2. Require MP to report in future TCR riders any net credits it received from MISO for other utilities use of the HVDC Modernization project once it is in service, as well as any other applicable future projects. (Department)