414 Nicollet Mall
Minneapolis, MN 55401

January 20, 2026

—Via Electronic Filing—

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

RE: REPLY COMMENTS
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-25-386

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments in response to the December 10, 2025 Comments of the Department of Commerce, Division of Energy Resources and January 5, 2026 Comments of the Office of the Attorney General – Residential Utilities Division.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Megan Spear at megan.spear@xcelenergy.com or me at rebecca.d.eilers@xcelenergy.com or 612-330-5570 if you have any questions regarding this filing.

Sincerely,

/s/

REBECCA EILERS
MANAGER, REGULATORY AFFAIRS

Enclosure
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENT S FOR 2026, TRACKER TRUE-UP, AND REVISED ADJUSTMENT FACTORS	DOCKET NO. E002/M-25-386 **REPLY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments to the Minnesota Public Utilities Commission in response to the December 10, 2025 Comments of the Department of Commerce, Division of Energy Resources (Department) and the January 5, 2026 Comments of the Office of the Attorney General – Residential Utilities Division (OAG) in the above-referenced docket.

We appreciate the Department's thorough review of the Company's 2026 Transmission Cost Recovery (TCR) Petition. In this Reply, we provide additional information as requested by the Department and respond to the OAG's recommendations.

REPLY COMMENTS

I. 2025 TRACKER BALANCE

The Department requested an explanation of the imbalance between 2025 revenue requirements and collections given the 2025 forecasted year-end balance of $10,377,007.

The 2025 balance is the result of a 2024 true-up of the MISO Regional Expansion and Cost Benefits (RECB) net revenue requirement. The previous Schedule 26A Indicative Annual Charges workbook, a monthly update received from MISO, included expenses forecasted from June 2024 through August 2025 based on the Multi-Value Projects (MVP) charges. MISO used this limited approach intending to best represent the expense assessment, rather than using the load share ratio. This was a change from MISO that resulted in an unintended shift. Going forward, we will resume receipt of the full expense tied to our load ratio share, which is consistent with how the amount was traditionally calculated. This adjustment will help reduce variances in the future and provide more accurate forecasts. There wasn't an adjustment in the Company's process to incorporate the RECB amounts, but the information calculated by MISO was different.

II. HOSTING CAPACITY ANALYSIS - FINAL COSTS

The Department requested final costs of the Hosting Capacity Analysis (HCA) project and its impact on the TCR. The Company provided the final costs for this project and the impact to the TCR in the initial Petition but did not specifically indicate the costs were final. The HCA project was completed and placed in-service in 2025. The final costs for this project are included in our Petition attachments and specifically presented on Attachment 3A: CWIP excluding Internal Labor and Attachment 3B: CWIP. The impacts to the TCR are shown on Attachment 4: Annual Tracker Summary. We provide below in Table 1 a comparison of initial HCA costs to the final project cost for ease of review.

Table 1
HCA Final Costs

Project	Initial Cost excl Labor[1]	Final Cost excl Labor	2026 Revenue Requirement
HCA	$1,423,190	$722,308	$162,455

III. 2026 MISO RECB EXPENSE

The Department requested additional information on the Company's projection of MISO RECB Schedules 26/26A net expenses in 2026, when the Company has in recent years seen net revenue credits.

[1] Cost as reflected in Attachment 5a in Docket No. E002/M-23-467

The timing of the Long Range Transmission Plan (LRTP) projects is the driver of the expense increase in excess of the credit. The nature of these projects and the construction of large transmission lines will incur expenses before producing revenue. Therefore, in 2026, when the LRTP2 Alexandria to Big Oaks project is in active construction there is an increase in Schedule 26A expense with a much smaller increase on the revenue side. Subsequently, for 2027 we see a large increase of Schedule 26A revenue, so in that period, the revenue requirement will decrease.

IV. AMI COST ALLOCATOR

The Department requested an explanation of the change in allocation method for AMI costs from how they have been previously allocated in TCR Riders. In addition, the OAG recommends the Commission not approve the Company's proposed AMI allocation method and recommends alternative methods instead. We provide additional support for our proposal below and explain why the OAG's proposed alternative methods are not appropriate.

A. Justification for Change in Allocation Method

In previous TCR Rider proceedings, the Company has used the P60 Distribution allocator to allocate AMI and other distribution costs that are recovered under the rider mechanism. This P60 allocator is derived from total distribution plant in service that has been allocated to customer class via customer- and demand-related allocators. To more accurately follow cost causation principles for cost allocation, the Company is proposing to use the C12WM[2] allocator from the 2024 Class Cost of Service Study (CCOSS) approved in the Company's 2022-2024 test year rate case (Docket No. E002/GR-21-630) to assign AMI project expenses to customer class.

As discussed in our Petition, Distribution-Grid Modernization costs recovered through the TCR Rider are assigned to NSPM's State Jurisdictions (Minnesota, North Dakota, and South Dakota) using direct assignment, or a general, intangible, customer count, or meter count allocation. In order to allocate to the Minnesota Jurisdiction Classes (Residential, Commercial and Industrial (C&I) Non-Demand, and C&I Demand), the distribution allocation factors approved in the Company's last electric rate case are used to allocate non-AMI Distribution-Grid Modernization costs while the C12WM allocator is used to allocate AMI-meter related costs. Transmission,

[2] This allocator is a customer-related allocator that uses customer counts that are weighted by meter cost weightings. The meter cost weightings are based on the actual meter replacement costs. An inventory of meter models installed for each customer-by-customer class was obtained from the Company's Meter Data Management System (MDMS). Metering staff provided current replacement costs for each meter model and metering costs were rolled up for each customer class.

Distribution-Grid Modernization, and AMI expenses are allocated to classes differently; therefore, we have separately allocated these investments in the TCR Rider.

B. Allocation Method is Reasonable Based on Cost Causation

The purpose of changing this cost allocation methodology is to assign AMI costs to customer class in a manner that more accurately reflects cost causation. Instead of using general distribution allocation factors that are classified as demand- and customer-related, the AMI costs are allocated based on the number of customers in each class, weighted by the meter cost weightings described above. This better reflects cost causation because AMI costs are driven by the addition of customers and not demand, as was used with the previous cost allocation methodology. For example, Residential, Small Commercial Non-Demand, Demand, and Street Lighting classes each receive a share of AMI costs proportional to their customer counts weighted by the meter cost weightings. The allocation is shown in Attachment 7 of the Petition, which breaks down the $48.1 million in AMI costs by customer class using this new "meter cost allocator."

C. AMI costs should not be classified as one-third customer-related, one-third demand-related, and one-third energy-related as the OAG recommends

The OAG proposes to classify meter costs as 1/3 customer-, 1/3 demand-, and 1/3 energy-related and provides several reasons for this proposal. First, the OAG claims that AMI meters provide a variety of benefits to customers including more effective load management, reduced line losses, reduced energy costs due to load shifting, reliability benefits, and allowing utilities to determine maximum loads on individual transformers. The OAG concludes that because AMI provides a wide range of customer-, demand-, and energy-related benefits, these costs should be classified and allocated with customer-, demand-, and energy-related allocators. While the OAG did propose how AMI costs should be classified, they did not make any proposal on what cost allocators should be used to allocate these costs. The OAG claims that the Company already classifies and allocates costs based on the benefits in the Company's CCOSS and mentions the Company's methods for classifying and allocating fixed production and economic development discounts. Finally, the OAG also claims that AMI meters cost three times as much as non-AMI meters by comparing current meter plant in service balances with balances from 2015-2021.

The Company disagrees with the OAG for several reasons. First, cost allocators should be based on cost causation, not the benefits that the technology provides. Our

AMI meters are installed because each customer requires a meter to receive and be billed for electricity. While it is true that AMI meters have additional functionality, that functionality does not change the fact that our metering costs are driven by how many meters we need to install, which is driven exclusively by the number of customers we serve and not by the usage or demand characteristics of that customer. It is our position that cost causation represents the most equitable approach for allocating meter costs among all customer classes.

In regard to the Company's plant stratification methodology, this method classifies fixed production into demand- and energy-related components to recognize that fixed production plant is designed, built, and operated to meet peak demand and provide low-cost energy to our customers. Fixed production costs are caused by both demand and energy needs. Further, the OAG points to consistency with the idea that the Company's method for allocating economic development discounts is driven by the benefits they provide. The Company's economic development discounts are provided to attract large customers. These customers generate additional revenues that contribute to total fixed system costs, which is a benefit to all customers. However, in this case, the cost of the economic development discount is driven directly by the benefit it provides. In the case of AMI meters, the cost of the meter is driven by the fact that each customer requires a meter for electric service. Any other functional benefit is not cost causative, and should not be represented as such in class cost allocation.

Finally, the OAG provides an apples-to-oranges comparison of AMI costs versus non-AMI costs by comparing 2024 meter plant-in-service balances with meter plant in service balances during 2015-2021. The OAG claims that since the meter plant-in-service balances in 2024 are three times what they were in 2015-2021, then non-AMI meters cost approximately 1/3 AMI meters and that amount of AMI costs should be customer-related. If classifying AMI costs as customer-, demand-, and energy-related was reasonable and based on cost causation, then it would make sense to compare current AMI costs with current non-AMI costs. Since current AMI meter costs are similar to non-AMI meters, it would still make sense to classify these costs as 100 percent customer-related.

D. AMI costs in the TCR Rider should be allocated using Xcel's C12WM allocator, which classifies AMI costs as entirely customer-related

The Company's new cost allocation method is intended to ensure that AMI costs are allocated more fairly and based on allocators that reflect cost causation. The C12WM allocator most accurately reflects cost causation because the cost weightings determine the actual meter cost for all of the customers on our system. In essence, this allocator determines the meter cost for every customer in each class.

E. Point of clarification for the proposed change in allocation of AMI project costs

The Company provides clarification of the OAG's observations concerning the proposed change in allocation of AMI project costs. The OAG asserted that this change would result in a cost shift increase of 16 percent in AMI costs for Residential customers and 75 percent for Commercial Non-Demand customers; however, the analysis did not include the E99 sales allocator, which is utilized to convert cost allocations into a TCR billing rate by customer class. When employing the correct TCR calculation, the cost shift increase is 10 percent for Residential and 47 percent for Commercial Non-Demand customer classes when compared to the previous methodology.

V. ALLOCATORS ARE BASED ON FORECAST DATA THAT ALIGNS WITH COMMISSION APPROVED METHODOLOGY

The OAG asserts that the Company is allocating TCR Rider transmission costs using outdated class allocators based on old sales and customer forecasts from a prior rate case. As explained below, the allocators are based on the Commission's decisions in previous TCR filings and approved rate cases and the proposed new class allocators are explained in the current rate case record.

The Company has long followed Commission precedent in utilizing approved allocation methodology and allocators when calculating TCR rider rates.[3] We acknowledge that this practice is not a perfect solution for capturing unforeseen actual changes to the broader system; however, it does provide a level of confidence that cost allocators and the cost allocation methodology being used in each TCR Petition have been thoroughly reviewed by stakeholders and deemed acceptable by the Commission through rate case proceedings. The material changes to the system that the OAG mentions in Comments would be reflected in the normal forecasting process that the Company conducts during its multi-year rate plan rate case proceedings. We believe that the use of approved 2024 allocators that are based on

[3] Rate design for these factors was approved in the Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 and the October 21, 2011 Order in Docket No. E002/M-10-1064. The rate design was amended in Docket No. E002/GR-12-961 where the Commission ordered that system coincident summer peak allocators should be used to allocate transmission costs, and again in Docket No. E002/GR-13-826 when streetlighting class was removed.

methodology approved in the Docket No. E002/GR-21-630 electric rate case is still appropriate for this current petition.

The OAG explains that as customer compositions change—especially with the addition of large data centers—using outdated allocators can misallocate costs and prevent new customers from sharing in fixed-cost burdens. The OAG asserts that updating the allocators matters now because the risk of misallocating TCR Rider costs is suddenly much higher than in prior years, primarily due to the anticipation of large customer loads. The Company appropriately monitors the addition of large loads, manages future risk and evaluates potential impacts to forecast, but so far, there have been no such impacts to the system that would require this suggested cost allocation for 2026. The OAG maintains that our allocators are outdated, but they reflect the finality and certainty of a Commission decision, rather than the potential for a future, unknown customer that does not currently place any demand on our system. The Company aligns allocators with the best-available and most-recent Commission-approved methodology which we believe more reasonably allocates costs among customers. Our proposal is a balanced classification that ensures fair and accurate cost distribution among customer classes, even with the potential for large new customers joining the system.

VI. PARTICIPANT COMPENSATION – SEP RIDER ADJUSTMENT

The Department recommends the $15,397 in participant compensation expenses be treated for recovery under the SEP Rider rather than the TCR Rider, consistent with Order Point 2 of the Commission's December 1, 2025 Order in our 2025 TCR Rider in Docket No. E002/M-24-371. We agree it is appropriate to treat participant compensation here in the same way. In compliance, we will remove participant compensation from the TCR tracker for 2025 and 2026 and provide an updated electric SEP Rider tracker to include the participant compensation initially proposed for inclusion in this Petition.

As discussed in our December 10, 2025 compliance filing in Docket No. E002/M-24-371, the Commission's June 16, 2025 Order in our last SEP Rider proceeding, Docket No. E002/M-25-135, approved a $0 SEP Rider rate and authorizes the Company to reduce the SEP Rider tracker account to $0 by netting the final under-collected amount, adjusted as needed for actual cancel/rebill activity, through the interim rate refund in Docket No. E002/GR-24-320. The current SEP Rider tracker balance, including 2024 and 2025 participant compensation, is $1,250,899. The Company intends to net the final SEP Rider under-collection through the interim rate refund in Docket No. E002/GR-24-320 at the conclusion of the rate case as previously approved by the Commission.

CONCLUSION

Through this Reply, we have provided additional information in response to the requests by the Department and recommendations by the OAG. We respectfully request that the Commission approve Xcel Energy's 2026 TCR Rider Petition as proposed.

Dated: January 20, 2026

Northern States Power Company

Certificate of Service

I, Victor Barreiro, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E002/M-25-386

Dated this 20th day of January 2026

/s/

Victor Barreiro
Regulatory Administrator

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