minnesota power

AN ALLETE COMPANY

April 3, 2026

VIA E-FILING
Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's
2025 Integrated Distribution Plan
Docket No. E015/M-25-140
UTILITY REPLY COMMENTS

Dear Ms. Bergman:

In accordance with the Minnesota Public Utilities Commission's November 13, 2025 Notice of Comment Period in the above referenced docket, Minnesota Power respectfully submits the attached Reply Comments.

If you have any questions regarding this filing, please contact me at (218-355-3016) or jgries@mnpower.com.

Respectfully,

Joshua H Gries

Joshua Gries
Public Policy Advisor

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2025 Integrated Distribution Plan	Docket No. E015/M-25-140 **UTILITY REPLY COMMENTS**

I. INTRODUCTION

Minnesota Power (or, the "Company") respectfully submits the following Reply Comments regarding the Company's 2025 Integrated Distribution Plan ("IDP"). These Reply Comments address questions and concerns raised by the Minnesota Department of Commerce ("Department") and Fresh Energy, Union of Concerned Scientists, Sierra Club, and Plug In America filing jointly as Clean Energy Groups ("CEGs").

II. BACKGROUND

On November 3, 2025, the Company submitted its fourth IDP to the Minnesota Public Utilities Commission ("Commission"). On November 13, 2025, the Commission issued a notice of comment period acknowledging the following submission deadlines: the closure of the Initial Comment period on March 13, 2026, the closure of the utility Reply Comment period on April 3, 2026, and the closure of the participant Reply Comment period on April 24, 2026. On March 13, 2026, the Department and CEGs filed Initial Comments in response to the Company's 2025 IDP.

III. SUMMARY OF INITIAL COMMENTS

The Department's comments, questions, and recommendations focused on the following themes and topics: budgetary evaluation, quantifying the value of reliability, ensuring assets are "right sized", wildfire accountability and mitigation, and the Transportation Electrification Plan ("TEP"). The CEGs recommended that the Commission approve the Company's 2025 TEP but with several recommended modifications. The Company generally supports the principles underlying the comments from the CEGs and Department and views the requests for clarification and response as contributing valuable context to the evaluation of the IDP. Although Minnesota Power recommends modifications to several of the Department and CEG's recommendations, the Company appreciates the thoughtful analysis and engagement from parties in this proceeding. The Company's responses to each comment, question, and recommendation are provided in detail below.

IV. REPLY COMMENTS

In Initial Comments, the Department issued various requests for information and submitted a series of formal recommendations to the Commission. The Company's responses to these requests are outlined in the following sections.

A. Substation Capacity

In Initial Comments, the Department raised two questions related to substation capacity. Specifically, the Department requested that the Company explain why the Blanchard and 15th Avenue West substations do not appear to have planned capacity mitigations in the Company's budget, and whether the Company considers the overloads at the Little Falls and Verndale substations to pose significant safety or reliability risks, and if so, how those risks will be mitigated.

The Company manages loading and associated safety and reliability risks at Blanchard, 15th Avenue West, Little Falls, and Verndale through a combination of continuous SCADA monitoring, established loading limits, and defined operating procedures to ensure these risks are mitigated. Additionally, several of these substations have been identified for investments and are outlined in the Company's 2025 IDP[1]. The Company would also note that for the Blanchard, 15th Avenue West, Little Falls, and Verndale substations, historical peak load exceeds the substations' firm capacity, but not total

[1] eDocket: 25-140; Document: 202511-224624-01; table 16; page 76

transformer capacity. The Company defines firm capacity as the capacity available following the loss of the largest single transformer at a given substation. When assessing substation capacity and planning needs, the Company relies on firm capacity where applicable. The Company conducts annual reviews of loading across all substations and re-prioritizes modernization projects based on a range of factors, including asset age and condition, reliability, capacity considerations, and constructability constraints such as outage coordination, equipment lead times, and site limitations.

The Blanchard Substation has approximately 28.3 MW of distributed energy resources ("DER") interconnected to its feeders, as well as the Company–owned hydro generation interconnected to the Blanchard distribution bus. This interconnected generation reduces loading on the Blanchard transformers such that peak loading remains below the substation's firm capacity rating. The substation peak loading values presented in Appendix F of the Company's 2025 Integrated Distribution Plan exclude utility-scale solar and hydro generation. The Company has a project identified in the five-to-ten-year planning horizon to replace aging assets at the Blanchard Substation. However, projects in this timeframe are subject to change as system needs and priorities evolve.

There is no project currently planned to increase the firm capacity of the 15th Avenue West Substation. Instead, as listed in the Company's 2025 IDP[2], the Company has identified the Duluth 34 kV Expansion Project, which will increase the overall load-serving capability of the Duluth 34 kV network and shift load away from the 15th Avenue West transformers, where current peak loading exceeds firm capacity.

With respect to the Little Falls and Verndale Substations, exceeding firm capacity presents a reliability risk during peak conditions only in the event of the loss of the largest transformer, at which point the remaining transformer would be insufficient to serve station load. In such an event, the Company would need to transfer load to adjacent

[2] eDocket: 25-140; Document: 202511-224624-01; table 16; page 76

feeder ties that have been identified through contingency analysis as having available capacity. Additionally, the timing of the Little Falls and Verndale Substation modernization projects reflects the relative prioritization within the Company's broader substation modernization portfolio which is also identified in the Company's 2025 IDP[3].

B. Age-Related Replacements and Asset Renewal

In Initial Comments, the Department asked one question related to substation capacity as part of the Age-Related Replacements and Asset Renewal portion of the Company's IDP: *"The Department requests the Company explain in reply comments how the company plans to address oversized system assets in its planned age-related replacements and asset renewal project[4].*

While the Department characterized Minnesota Power's system assets as "oversized," the Company sizes its system assets based on the reliability and operational needs of the system. Systems are planned to ensure that reliability can be maximized at the least possible capital cost by leveraging standard sizing and construction methods. In internal power flow studies, the Company will identify max loading on distribution assets in baseline analysis (N-0) with future load growth and contingency (N-1) analysis. The baseline analysis will identify if there are any existing or near-term thermal overloads when the distribution system is in its normal configuration. Contingency analyses will evaluate the distribution system assets to provide backup capability with an adjacent external feeder. The assets will be sized to create full capacity ties that would allow the Company to back up the load on any feeder or substation during any planned or unplanned outages during the year.

For operational efficiency, the Company uses standard sizes across all our system assets when applicable. For example, the Company has two standard T-D transformer sizes to

[3] eDocket: 25-140; Document: 202511-224624-01; table 16; page 76
[4] eDocket: 25-140; Document: 20263-229266-1; Page 19

select from when planning substation modernization or targeted asset renewal projects. Using standard sizes across our system allows for common equipment specification and engineering designs. Standard equipment sizes also allow for a common spare strategy across our system which allows for a faster response replacing failed assets in addition to cost savings by minimizing the carry-costs of additional inventory.

C. Non-Wires Alternatives (“NWA”)

As described in section VII of the Company’s 2025 IDP filing, the Company did not have any distribution projects over $2 million that meet the criteria for being a viable candidate for NWA (NWA discussion starting on page 70 of the Company’s 2025 IDP). However, the Company did include benefits from both energy efficiency and renewable generation in its cost-benefit analysis as part of its 2023 NWA study. The Wrenshall scenarios in the NWA study included collocating a battery energy storage system (“BESS”) next to the existing Wrenshall Community Solar Garden. While the project was not selected, the Wrenshall scenario evaluated long-term considerations for the configuration and operation of the Wrenshall area 13.8 kV system given its varied characteristics and constraints. All scenarios in the 2023 Non-Wire Alternative Study included assessment of non-wire solutions such as integrated volt-var control (energy efficiency) to improve power quality and conservation voltage reduction (“CVR”), battery energy storage system to provide backup capability (demand response), and fault location, isolation, and service restoration (”FLISR”).

The Company appreciates the Department’s reference to the Distributed Solar Energy Standard (“DSES”) and potential opportunity to pair distributed solar with future NWA solutions. As described in the Company’s response to DOC IR 27, the Company issued its first DSES request for proposals on January 30, 2025. The Company did not submit any self-build proposals into the first DSES RFP and therefore did not have control over the location of proposed projects. Project selection is currently ongoing, and as such, the

Company cannot provide details as to the location or details of forthcoming DSES projects.

The Company has a long history of supporting energy efficiency, demand response, and renewable generation through customer programs. However, fully leveraging these demand-side resources for NWA purposes presents several challenges. Participation in customer programs can vary over time, and customers may change equipment, behavior, or enrollment without notice, making it difficult to guarantee consistent and dispatchable load relief. Without enhanced monitoring, automation, and verification tools, these uncertainties make demand-side resources difficult to depend on as primary NWA solutions. The Company will continue to include these resources in future NWA evaluations and assess additional opportunities to integrate demand-side applications into future NWA analyses as enabling tools evolve.

D. Wildfire Mitigation Plan

In Initial Comments, the Department asked one question related to the Company's Wildfire Mitigation Plan: *"The Department requests the Company, in Reply Comments, indicate whether its Wildfire Mitigation Plan will be completed by the filing of its next IDP (to be filed in 2027)[5]."*

The Company expects to have a completed Wildfire Mitigation Plan ("WMP") by midyear 2026; however, development of a comprehensive investment strategy for wildfire mitigation projects is not anticipated to be complete before the Company's next IDP filing in 2027. As identified in the Company's 2025 IDP, the Company is working diligently with a consultant to develop a comprehensive WMP designed to 1) minimize the risk of ignitions caused by the Company's assets 2) minimize the risk of injuries to wildfire responders and 3) prevent serious damage to the Company's electrical assets from wildfires within its service territory. The Company's WMP framework is organized around

[5] eDocket: 25-140; Document: 20263-229266-1; Page 24

four pillars: 1) situational awareness, 2) system preparedness, 3) operational practices, and 4) communication and public outreach. Development of the WMP investment plan is also complicated by the absence of historical wildfire-related outages and associated costs in the Company's service territory, which limits the useability of traditional cost-benefit methodologies requisite to the implementation of phase four of the Company's WMP. Although the WMP investment plan will not be fully complete by 2027, the Company anticipates having substantial progress and key elements of the framework developed by the time of its next IDP filing and will be able to provide an updated description of its WMP status and approach in that filing.

The Department made two reform recommendations to the Commission regarding the development of the Company's WMP portion of the 2025 IDP. First, the Department recommended that the Commission require the Company to file a compliance filing in this docket upon completion of Phase One of its WMP. That compliance filing should include the results of Phase One, including the Company's wildfire risk map and the methodology used to develop it, identification of hazardous fire areas, a timeline for completion of the remaining phases, and a proposed budget for continued development of the plan. Second, the Department recommended that the Commission require the Company to file its completed WMP as an attachment or supplement to its IDP. The Department further recommends that the Commission require the Company to include, at a minimum, a description of the Company's intent in mitigating wildfire risk, such as whether the focus is on mitigating utility-caused wildfires, minimizing liability, or reducing fire damage to utility assets. The WMP should also include a definition of "wildfire" as it is used for utility identification, planning, and mitigation purposes, along with a discussion of the Company's risk-modeling, mapping, and project-prioritization processes. In addition, the Department recommends quantification of actual wildfire risk within the Company's service territory based on the probability of a fire, inclusion of the most recent version of the Company's wildfire risk map accompanied by a narrative explanation of the highest-risk areas and any changes from prior iterations, and reporting on the number and location of wildfires experienced in the Company's service territory, the number of outages caused by wildfire, and the average duration of wildfire-related outages over the past ten years. Finally, the Department recommends reporting on the effectiveness of the Company's wildfire mitigation strategy in reducing wildfire-related outages and inclusion of a full cost-benefit analysis for any proposed mitigation measures.

To these recommendations, the Company respectfully requests that the Commission consider the following regarding the timing and forum for WMP filings. Specifically, the Company requests that the Commission 1) decline to require a formal WMP compliance filing immediately following completion of phase one and 2) open a separate docket for utility WMP.

To the Department's first recommendation, the Company would note that in addition to the Company's response to the Department's request to include a finalized WMP with the 2027 IDP, the Company is designing its WMP as a single, interrelated, and iterative four-phased framework rather than a series of independent phases. Therefore, the Company believes a formal compliance filing at the conclusion of phase one would only provide an incomplete snapshot of the Company's WMP, not the overarching framework the Company intends to implement.

Additionally, as identified in the Company's 2024 Safety, Reliability and Service Quality Standards Report[6] ("SRSQ"), the customers of the Company's service territory haven't been subject to any wildfire-related outages to date. Although this is positive from a reliability and safety standpoint the lack of historical data poses an additional challenge to the Company in developing CBAs as stated previously. If the Commission or Department still prefers visibility, the Company is willing to provide informational updates or participate in working groups following phase 1 without requiring these information updates to be considered a compliance filing.

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[6] Docket No. E015/M-25-29; Document 202511-225185-01

Regarding the Department's second request that the WMP be filed with the IDP, the Company would note that wildfire risk is a state-wide and interconnected risk and evaluating WMPs solely within a utility's IDP may risk a siloed approach to managing this risk by 1) constraining the Commission's ability to compare approaches across utilities 2) reduces utilities' opportunities for alignment, coordination, and integration of risk mitigation strategies and 3) make the analysis of wildfire mitigation plans more complex for interested parties like the Forest Service or Department of Natural Resources ("DNR"). Furthermore, because wildfire mitigation strategies are integrated across utility operations including generation, transmission, and distribution, filing the WMP as part of the IDP would not account for the enterprise-wide impacts that the WMP will have on the Company.

E. Reporting Metrics and Methodology

In Initial Comments, the Department made three reform recommendations regarding the Company's planned System Expansion or Upgrades for Reliability and Power Quality section of the 2025 IDP. First, the Department recommends that the Commission require the Company to develop clear and consistent reporting metrics for its reliability projects such as miles converted or segments addressed and to provide a transparent methodology for selecting distribution system segments. Second, the Department recommends that the Commission require the Company to quantify the value of major reliability and resiliency investments, including strategic undergrounding, using a recognized customer interruption cost methodology (e.g., an Interruption Cost Estimate ("ICE") calculator) and to apply this valuation consistently in cost-benefit comparisons across alternatives. Third, the Department recommends that strategic undergrounding be evaluated alongside other reliability tools capable of materially reducing outage minutes on targeted feeders.

The Company appreciates the Department's feedback regarding these matters and shares the goal of providing transparent reporting and robust cost-benefit analyses to ensure the highest value and lowest cost for ratepayers. The Company currently utilizes a holistic framework for selecting distribution segments that evaluates asset condition, performance metrics such as system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI"), and evolving market demographics, in addition to comparing any proposed investment against a no-action baseline. In the future, the Company will add additional inputs to the framework such as wildfire risk. The Company has also engaged external consultants to assess individual values of individual grid mod programs such as FLISR and strategic undergrounding and is committed to developing the clearer reporting metrics requested by the Department to enhance grid visibility.

While the Company agrees that quantifying the value of reliability and resiliency is essential, the Company proposes the Commission consider phased implementation of the ICE calculator or similar tools rather than an immediate mandate. Because the Company serves a unique blend of large industrial customers with far higher interruption costs and dispersed rural populations whose interruption costs also differ from national survey data, a generic ICE-based approach could introduce significant methodological bias and skew cost-benefit analyses to favor underinvestment. To mitigate these risks, the Company proposes a modification of the Department's recommendation to allow the Company to work with the Department and other interested stakeholders to evaluate options for quantification tools. Finally, the Company agrees with the evaluation of strategic undergrounding alongside other reliability tools and views targeted undergrounding as a vital component of grid modernization, particularly for feeders where traditional vegetation management or other preventative measures cannot sufficiently mitigate routine and more novel risks, including wildfires, or reduce outage minutes.

F. Age-Related Replacements and Asset Renewal

In Initial Comments, the Department made one reform recommendation to the Commission regarding the Company's Age-Related Replacements and Asset Renewal portion of the IDP:

> *"The Department recommends the Commission order MP to conduct a cost benefit analysis ("CBA") of all Age-Related Replacements and Asset Renewal projects with a 5-year budget of $10 million or greater. The cost benefit analysis should compare depreciation-level spending to MP's planned Age Related Replacements and Asset Renewal budget. In this analysis, MP should estimate reliability impacts in both cases and monetize the value of reliability to compare the cost effectiveness of MP's accelerated budget plan. The cost benefit analysis should be filed in MP's 2027 [7]."*

The Company appreciates the Department's focus on the cost-effectiveness of asset renewal and shares the goal of ensuring efficient capital allocations to maintain and improve grid reliability and resilience. However, rather than utilize a nominal baseline such as depreciation-level spending that might lead to an underinvestment bias, the Company proposes the Commission consider a modification to the Department's recommendation to allow the Company to work with a consultant on innovative new cost-benefit analysis programs and alternative baselines to depreciation-level spending that may be more representative of the Company's forward-looking approach to asset renewal, grid modernization, and risk management initiatives. The Company is willing to include the results of these efforts in the 2027 IDP.

[7] eDocket: 25-140; Document: 20263-229266-1; Page 17

G. Planned Grid Modernization Initiatives

In Initial Comments, the Department made one reform recommendation to the Commission regarding the development of the Company's Planned Grid Modernization Initiatives portion of the IDP:

> *"The Department recommends the Commission require MP to report on the actual reliability benefits and actual costs of the projects in its grid modernization budget category in its next IDP. The reporting of actual reliability benefits and actual costs should include at least MP's FLISR, Motor Operated Disconnect Switches (MODS), and Single Phase Reclosers projects, as well as the Askov and Kerrick Battery Energy Storage Systems (BESS) projects. Where there is sufficient data, reporting should include the actual reliability benefits and costs of individual [8]."*

The Company appreciates the Department's recommendations and shares the goal of ensuring that grid modernization investments deliver verifiable value to our customers and the system. To that end, program budgets are identified in the 2025 IDP. Specifically, section VII. Distribution System Modernization and Infrastructure Investment Plans, and actual reliability benefits associated with FLISR, MODS, and recloser projects are currently captured and provided within the annual SRSQ[9] report. Specifically, section V. "Reliability Metrics Reporting". The Company tracks these metrics by feeder once the project to a specific feeder is complete. If this existing reporting structure and format does not fully comply with the Department's objectives, the Company welcomes continued dialogue with the Department to identify a more equitable and innovative solution that provides transparency, integrity, and efficiency.

[8] eDocket: 25-140; Document: 20263-229266-1; Page 26
[9] Docket No. E015/M-25-29; Document 202511-225185-01

H. Transportation Electrification Plan

In Initial Comments, the Department raised several questions regarding the Company's TEP and requested further clarification in Reply Comments. The Department requested that the Company explain why utilization of the Commercial Public Charging electric vehicle (“EV”) Rate is low and discuss how the Company intends to increase utilization of the rate going forward. At the time of filing, there were 74 public EV charging stations, representing both level 2 and level 3 chargers, in the Company’s service territory according to EV Atlas Hub[10]. Today, there are 84 public charging stations, 32 of which include a level 3 charger. The Commercial Public Charging EV Rate requires the installation of a separate service. As a result, sites with level 3 chargers typically see greater economic benefits from participating in this rate, whereas public level 2 chargers are commonly installed on the customers’ existing service. There are currently 35 charging stations on the Commercial Public EV rate, of which 26 sites include a level 3 charger. This represents an 81 percent utilization rate for level 3 chargers and 17 percent utilization or charging stations with only level 2 chargers.

The Company works closely with customers, electricians, and car dealerships to increase awareness of its EV charging rate options. The Company will continue to share this information and is planning to increase engagement efforts in 2026 with the creation of a participating electrician network as approved in the Commission’s July 29, 2025 Order[11] Approving the Program with Modifications.

In addition, the Department requested that the Company provide more detailed information regarding historical and future EV spending. That information is provided in Tables 1 and 2 below:

[10] Charging Deployment Dashboard – Atlas EV Hub
[11] Docket No. E015/M-23-258; Document No. 20257-271524-01

Table 1: Historical EV Spending

	2021	2022	2023	2024	2025	Total
Distribution - Capital DCFC*		$2,043	$3,239	$1,587,793	$2,681,638	**$4,274,713**
Distribution O&M DCFC				$313,367		**$313,367**
Customer Programs Other* EV Education & Outreach	$18,132	$1,126	$3,483	$4,155	$2,446	**$29,342**
Customer Programs Other* EV Program Delivery	$41,818	$11,559	$42,675	$5,595	$20,605	**$122,252**
Customer Programs Other* EV Program Labor	$81,632	$106,407	$139,446	$116,821	$97,202	**$541,508**
Customer Programs Other* Second Service Rebate		$4,500	$8,500	$4,000	$7,000	**$24,000**
Customer Programs Other* Smart Charger (Level 2) Rebate		$4,500	$23,414	$23,642	$27,830	**$79,386**
Grand Total	**$141,581**	**$130,135**	**$220,756**	**$2,055,373**	**$2,836,720**	**$5,384,567**

*Anticipated tax credit benefits not included in total cost.

Please note that program-related labor was inadvertently omitted from the 2025 IDP[12] in the TEP and has been added in the above table in the line titled Customer Programs Other* EV Program Labor. The table above is also reflective of the remainder of 2025 as requested.

Table 2: Future EV Spending

	2026	2027	2028	2029	2030
Make Ready (Utility-Side)	$280,000	$300,000	$310,000		
Make Ready (Customer-Side)	$287,000	$343,000	$408,500		
Education & Outreach	$15,000	$15,000	$15,000	$15,000	$15,000
MDU Smart Level 2 Rebate	$2,500	$5,000	$5,000		
Total	**$584,500**	**$663,000**	**$738,500**	**$15,000**	**$15,000**

As stated in the Company's TEP, the figures included above represent the costs associated with the Make Ready Pilot[13]. Costs associated with transportation

[12] eDocket: 25-140; Document: 202511-224624-01; Appendix E; Page 21
[13] Docket No. E015/M-23-258

electrification initiatives included in the upcoming Energy Conservation and Optimization ("ECO triennial are unknown and are therefore not included. Additionally, the Company did not include an assumption for labor which is recovered through base rates. Historically, EV labor has primarily been dedicated to the Company's direct current fast charging ("DCFC") project and supporting customer inquiries. EV customer program labor consists of activities required to promote and deliver EV programs including responding to customer questions, creating awareness about EVs at community and customer events, and delivering customer programs.

Finally, the Department recommends the Commission require the Company to report on the following in future TEPs:

1. The percentage of its commercial sites located in areas disproportionately impacted by transportation pollution, broken out by commercial program.
2. The percentage of residential EV program customers located in areas disproportionately impacted by transportation pollution, broken out by residential program.
3. The percentage of residential EV program customers that live in areas where both renters and multifamily units make up 50 percent of the housing units, broken out by program.
4. The percentage of residential EV program customers located in census tracts where 40 percent or more of the people identify as people of color, broken out by program.
5. The percentage of residential EV program customers located in census tracts where 35 percent or more of households have an income that is at or below 200 percent of the federal poverty level, broken out by program.
6. The percentage of residential EV program customers located in rural communities, broken out by program.

The Company appreciates the recommendations from the Department and CEGs regarding the tracking of specific demographic and geographic metrics for EV programs. The Company shares the values inherent in these requests and the objectives of ensuring that the benefits of transportation electrification are distributed equitably across the Company's service territory. The Company is committed to analyzing these metrics to the greatest extent possible.

However, the Company notes that several of the requested data points present significant challenges. Unlike the standard environmental justice metrics found at the Minnesota Pollution Control Agency's Environmental Justice Map, some of the specific datasets requested are not available as actionable overlays. The Company will work to provide this information within the constraints of available and usable data. Additionally, where actionable overlays are not readily available, the Company may propose collaboration with interested parties to identify reasonable proxies to ensure the Department and CEGs intent for the tracking requirement is met without creating an undue administrative burden on the Company. The Company looks forward to continued collaboration to refine these reports as data improves.

Regarding the CEG's Initial Comments, the Company appreciates the thorough review and thoughtful suggestions to its TEP. The Company provides responses to the CEGs requests for additional information and modifications in the sections below.

The CEGs requested clarification regarding the level of investment planned in the Company's upcoming ECO Triennial Plan filing, stating:

> "*Although these ECO plans may not have been finalized at the time of filing, the CEGs ask that the Company further clarify their intentions and estimated ECO investments in transportation electrification in their Reply Comments*[14]."

[14] eDocket: 25-140; Document: 20263-229273-01; Page 3

The Company recognizes that information about total EV spending, inclusive of future ECO programs, would provide a more holistic view of planned EV investment. The Company will be filing this information in its ECO Triennial Plan on June 1, 2026 and looks forward to discussing any questions in that proceeding.

Additionally, the CEGs made several recommendations in Initial Comments related to commercial EV programs. Specifically, the CEGs encourage the Commission to direct the Company to address barriers to transportation electrification by proposing a make-ready program for commercial fleet electrification as a supplemental filing to this TEP; surveying customers to better understand how existing commercial offerings could be improved and how participation in those programs could be increased; including rebates for electric buses—including transit and school buses—both as a modification to the current ECO Triennial Plan and in the next Triennial; and including a fleet advisory services program in its ECO Triennial Plan filing.

The Company's Make Ready Pilot Program was approved in the Commission's July 29, 2025 Order.[15] This pilot is intended to test the effectiveness of the make ready program model in encouraging the installation of EV charging infrastructure in different applications including multifamily buildings, public charging and workplace charging. As noted by the CEGs, the fleet sector was originally included in this pilot proposal but was removed as a result of interested parties' feedback received throughout the regulatory process. The Company is currently implementing the Make Ready Pilot, as approved, and is looking forward to results which will be used to inform potential future expansion of the program. Expansion at this time would be premature as it would precede evaluation of the existing pilot and could cause confusion among customers and trade allies.

Additionally, the Company will provide support for electric vehicles in its upcoming ECO program including electrification analysis and rebates. The electrification analysis will

[15] Docket No. Docket No. E015/M-23-258

focus on full facility electrification opportunities (including fleets), similar to the existing energy analysis offering. As stated in the TEP, the Company is also planning to provide rebates in its upcoming ECO Triennial Plan filing for electric buses to be effective in 2027, if approved. A modification to the existing ECO Triennial would require support from resources that are currently dedicated to the development of the Triennial plan. By the time a modification could be submitted and approved, the new Triennial would be nearly in effect. Finally, the Company is currently surveying commercial customers to better understand the effectiveness of existing commercial EV programs and hopes to better understand demand for fleet electrification specifically. The results of this survey will inform future commercial EV proposals.

The CEGs further recommend that the Commission direct the Company to develop a new residential demand-response program to support grid-optimized EV charging and improve affordability without requiring a second service meter, and to explore future pilot offerings that support affordable and equitable access to electric transportation options, including electric carshare programs. The Company plans to provide rebates for the purchase of an electric vehicle in its upcoming ECO Triennial Plan filing and will assist customers in determining which charging rate is most suitable for their charging needs. In addition to time-based rates that do not require the installation of a second service, such as the residential Time of Day rate, the Company is also exploring opportunities to utilize submetering in the future. This would reduce the upfront cost of participation in rates that require a dedicated service. The Company has also explored electric ride share programs and will continue to evaluate the effectiveness of these offerings in the Company's service territory.

VII. CONCLUSION

The Company appreciates the opportunity to clarify and respond to the comments submitted by the Department and CEGs regarding the Company's 2025 IDP. The diverse perspectives foster thoughtful, constructive dialogue that enhances transparency, encourages innovation, and supports informed decision-making. This collaborative engagement enables the Company to maintain a stable, reliable electric grid while meeting the evolving needs of customers across its service territory.

If you have any questions regarding this filing, please contact me at 218-355-3016 or jgries@mnpower.com.

Date Submitted: April 3, 2026

Respectfully submitted

Joshua Gries
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Minnesota Power
30 W Superior St.
Duluth, MN 55802

STATE OF MINNESOTA)
)ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

I, Amy M. Honkala of the City of Duluth, County of St. Louis, State of Minnesota, hereby certify that on the 3rd day of April, 2026, I electronically filed a true and correct copy of Minnesota Power's **Reply Comments in Docket No. E015/M-25-140** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on eDocket's Official Service List for this Docket were served as requested.

Amy M. Honkala