MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**Thursday, July 30, 2026**	**Agenda Item **3**
Company	Minnesota Power	
Docket No.	E015/M-25-140	

In the Matter of Minnesota Power's 2025 Integrated Distribution Plan

Issues

1. Should the Commission accept or reject Minnesota Power Company's 2025 Integrated Distribution Plan (IDP)?
2. Should the Commission approve, modify, or reject Minnesota Power's 2025 Transportation Electrification Plan (TEP)?
3. Should the Commission require any additional information or adjust any of the IDP filing requirements for Minnesota Power?
4. Should the Commission take any other action related to Minnesota Power's IDP?

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✓**Relevant Documents**	**Date**
Minnesota Power – Initial Filing	November 3, 2025
Department of Commerce – Initial Comments	March 13, 2026
Clean Energy Groups – Initial Comments	March 13, 2026
Minnesota Power – Reply Comments	April 3, 2026
Department of Commerce – Reply Comments	April 24, 2026

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I. STATEMENT OF ISSUES

1. Should the Commission accept or reject Minnesota Power Company's 2025 Integrated Distribution Plan (IDP)?
2. Should the Commission approve, modify, or reject Minnesota Power's 2025 Transportation Electrification Plan (TEP)?
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II. BACKGROUND

The Commission established IDP filing requirements for Minnesota Power (or "the Company") in its February 20, 2019 Order Adopting Integrated Distribution Plan Filing Requirements in Docket E111/CI-18-254. The purpose of these requirements is to ensure that the utility's IDP meets the following objectives:

1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
2. Enable greater customer engagement, empowerment, and options for energy services;
3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
5. Provide the Commission with the information necessary to understand the utility's

short-term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

On September 16, 2024, the Commission accepted Minnesota Power's 2023 IDP with modified filing requirements in its Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements in Docket E-111/M-23-258[1]. This Order began a series of working groups facilitated by Commission staff to modify the filing requirements in line with the Commission's Order and ahead of the Company's next IDP filing in 2025.

On June 3, 2025, the Commission issued its Notice of Approval of Updated Filing Requirements resulting from the work groups, outlining the newly modified filing requirements for Minnesota Power's 2025 IDP.[2]

On November 3, 2025, Minnesota Power filed its 2025 Integrated Distribution Plan ("IDP").

On November 13, 2025, the Commission issued a Notice of Comment Period asking parties to answer the following questions regarding the 2025 Minnesota Power IDP:

1. Should the Commission accept or reject Minnesota Power's IDP?
2. Did Minnesota Power adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice?
3. Feedback, comments, and recommendations on the following areas of Minnesota Power's IDP:
    a. Non-wires alternatives analysis
    b. Planned grid modernization initiatives
    c. Forecasted distribution budget
    d. Distributed Energy Resources (DER) scenarios and forecasts
    e. DER interconnection process
    f. Pilot projects
4. Other areas of Minnesota Power's IDP not listed above, along with any other issues or concerns related to this matter.

On March 13, 2026, the Clean Energy Groups and the Department of Commerce ("the Department") filed initial comments.

On April 3, 2026, Minnesota Power filed reply comments.

On April 24, 2026, the Department filed final reply comments.

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[1] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power Company's 2023 Integrated Distribution Plan*, Order Accepting 2023 Integrated Distribution Plan and Transportation Electrification Plan, and Modifying Filing Requirements, September 16, 2024 (hereinafter "2023 IDP Order").

[2] Docket No. E-015/CI-18-254/M-23-258/M-25-140, *In the Matter of Minnesota Power Company's 2023 Integrated Distribution Plan*, Notice of Approval of Updated Filing Requirements, June 3, 2025 (hereinafter "updated filing requirements approval").

III. IDP Summary

Minnesota Power is an investor-owned utility that is a division of ALLETE, Inc. ("Allete"). It provides electricity to approximately 150,000 retail customers, 14 non-affiliated municipal customers, and some of the nation's largest industrial customers across its service territory of around 26,000 square miles.[3] The Company noted that its customer mix is as follows: 14% commercial, 12% residential, and 74% industrial. Minnesota Power's service territory covers much of northeastern Minnesota, spanning rural as well as urban communities across large geographic distances.

Minnesota Power's distribution system contains 6,253 miles of distribution lines, 329 distribution feeders, and 193 distribution substations.[4] The Company currently has 4,542 miles of above ground wire on the distribution system and 1,711 miles of underground wire.

A. Distribution Capital Spending

Distribution Budget Categories: Minnesota Power broke down its distribution spending into the following categories:[5]

1. Replacements and Asset Renewal
2. System Expansion or Upgrades for Capacity
3. System Expansion or Upgrades for Reliability and Power Quality
4. New Customer Projects and New Revenue
5. Grid Modernization and Pilot Projects
6. Projects Related to Local (or Other) Government Requirements
7. Metering
8. Other

MP stated that many assets on its distribution system are nearing or exceeding their end of life, necessitating replacement and modernization to avoid service disruptions.[6] Moreover, the Company noted that the increasing penetration of DERs, wildfire risk, extreme weather patterns, and grid modernization efforts are introducing new operational complexities and prompting the need for new infrastructure investments. For instance, MP indicated that projects that promote distribution grid visibility, control, and hardening would contribute to rising capital and operational costs.

MP highlighted that it follows a depreciation-level spending pattern for its distribution system.[7] Beginning in 2022, the Company increased its investments above depreciation-level spending to accelerate its Asset Renewal, Grid Modernization, and Reliability projects.

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[3] Docket No. E-015/M-25-140, *In the Matter of Minnesota Power Company's 2025 Integrated Distribution Plan*, Compliance Filing, November 3, 2025 (hereinafter "the IDP" or "Petition"), at 11.

[4] *Id.*, at 13.

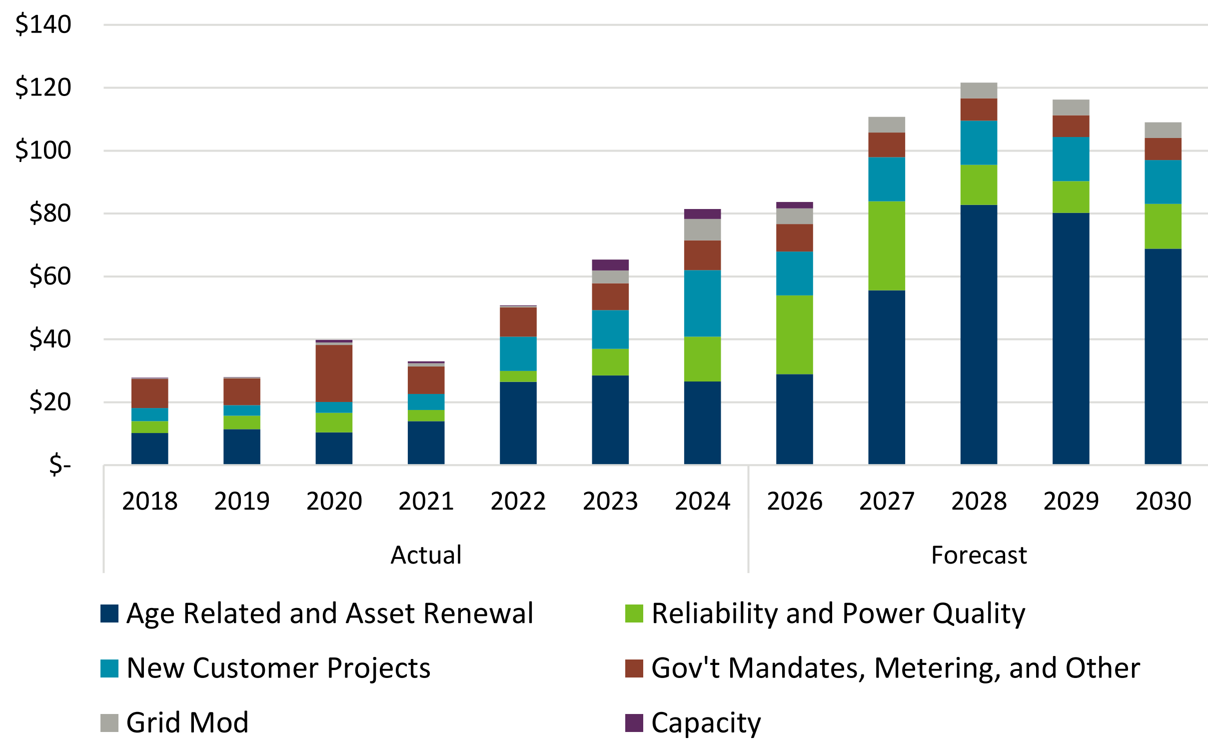
[5] *Id.,* at 58.

[6] *Id.,* at 57-58.

[7] *Id.,* at 58-59.

Figure 1 below depicts Minnesota Power's historic and forecasted distribution spending by capital categories from 2018-2030:

Figure 1: Actual and Budget Distribution Capital Expenditures by Minnesota Power Capital Budget Category ($M)



The Department noted that the greatest increase in MP's distribution capital budget spending occurs in the Age-Related Replacements and Asset Renewal category and in the System Expansion or Upgrades for Capacity category.[8]

1. <u>Age-Related Replacements and Asset Renewal</u>

Minnesota Power described its Optimized Asset Renewal process as "the process by which the Company replaces distribution assets like poles, transformers, and substations that have reached or are reaching the end of their useful life."[9] The Company noted that it does not replace like for like but instead makes upgrades with newer technologies as replacements occur. Several examples include: AMI, FLISR, and wildfire risk mitigation.

Given that many of Minnesota Power's assets are over 40 years old, the Company bolstered its Optimized Asset Renewal programs to target areas known to impact customer reliability and

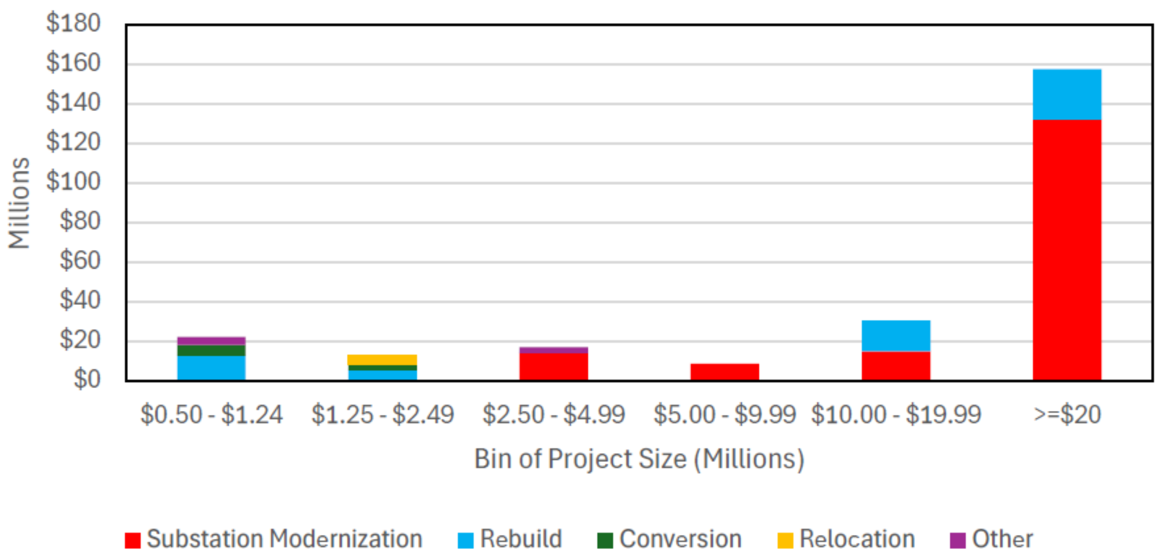
[8] Docket No. E-002/M-25-140, *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, Comments of the Minnesota Department of Commerce, March 13, 2026 (hereinafter "Department initial comments"), at 4-6.

[9] Petition, at 8-9.

system resiliency.[10] Minnesota Power noted that its approach involved targeting specific feeders and substation-connected assets. The Company's experiences with multiple failures in a single area of the system or due to a specific asset type in turn informed the Company's direction of distribution capital spending. In contrast, some failures are unanticipated and led to age-related replacements throughout the year. Minnesota Power explained that when failures had broader impacts and longer lead times to fix, the Company prioritized proactive asset renewal and grid modernization projects based on the age, past performance, and direct customer impact of major substation equipment.

The Department noted that MP planned to spend $327 million on projects in this category between 2026-2030.[11] The Department provided a graph that broke down the near-term projects undertaken by MP that total $249 million.

Figure 2: MP Age Related and Asset Renewal Budget Breakdown by Cause and Spending



The Department asked MP to provide a yearly estimate of its Age-Related and Asset Renewal Budget between 2026-2030 that reflected depreciation-level spending, along with the negative consequences of returning to depreciation-level spending and the reduction in CMO savings resulting from increased investments versus depreciation-level spending. The Department indicated that MP's response was qualitative, even though the Department sought more quantitative data, such as the benefits of this budget category as well as the reliability cost of outages.[12] The Department noted that without quantifying the reliability cost of outages, neither MP nor intervenors in the IDP docket knew the costs and benefits of MP's accelerated depreciation budget.

Given the high cost of transformers, the Department elaborated that every year that existing

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10 *Id.*, at 60-61.

11 Department initial comments, at 15-17.

12 Department initial comments, at 17.

transformers remain in use means significant deferred costs of costly infrastructure. On the one hand, the Department acknowledged that substation outages were the highest consequence outage events that are difficult to repair while long lead times also made replacement challenging during equipment failures. Nonetheless, while the Department agreed in erring in favor of reliability, the Department still sought to understand the reason behind the accelerated replacement plan.

Indeed, the Department pointed to MP's 2026-2030 Age-Related Replacements and Asset Renewal budget of $307 million (in 2025 dollars) which was greater than MP's entire 2020-2024 distribution budget of $297 million (in 2025 dollars). The Department cautioned that this large of an increase necessitated an enhanced analysis of MP's distribution budget projects.

As such, the Department recommended that the Commission order MP to conduct a cost benefit analysis (CBA or BCA) of all Age-Related Replacements and Asset Renewal projects with a 5-year budget of $10 million or greater.

In reply, MP suggested a modification to the Department's recommendation proposing that the Company be allowed to work with a consultant on innovative new cost-benefit analysis programs and alternative baselines to depreciation-level spending.[13] MP reasoned that using a nominal baseline like depreciation-level spending may lead to underinvestment bias. The Company noted that an alternative approach may be more representative of the Company's forward-looking approach to asset renewal, grid modernization, and risk management initiatives and that it was willing to include the results of these efforts in the following 2027 IDP.

The Department agreed with MP's modification of the Department's recommendation for MP to conduct a cost-benefit analysis of its Age-Related Replacements and Asset Renewal projects using a realistic alternative baseline for comparison instead of depreciation level spending.[14] (**Decision Option 4**)

2. <u>Inspection Programs and Failure Rates</u>

The Department used Minnesota Power's pole replacement program as an example of how the Department evaluates MP's inspection programs.[15] Between 2023-2024, MP had a very low pole failure- rate for the fleet-wide average, and in the Department's view, its current replacement spending already far outweighs the reliability benefits gained. Even if MP increased its budget by 10%, the added reliability benefit would be very small.

The Department remarked that "MP's current pole replacement rate is significantly lower than the expected lifespan of its power poles, and therefore its pole replacement budget should increase significantly when its power pole stock ages." The Department further noted that MP should analyze the cost effectiveness of its largest Age-Related Replacements and Asset

[13] MP reply comments, at 12.

[14] Department reply comments, at 12.

[15] Department initial comments, at 19-21.

Renewal projects.

The Department stated that it planned to revisit MP's inspection programs in its 2027 IDP.

B. System Operations

1. Control and Monitoring Systems

The Company uses four key system tools to monitor and control its distribution system:[16]

Table 1: Minnesota Power's Tools to Monitor and Control its System

Monitoring and Control Method	Purpose	Details
Supervisory Control and Data Acquisition (SCADA)	Oversees the state and health of the distribution system on roughly half of Minnesota Power's feeders.	The SCADA system reports analog measurement data from feeders. The data is recorded in a database accessible for engineering planning and analysis. MP can also use SCADA to remotely operate breakers and motor-operated switches to isolate faulted equipment and feeder sections.
Smart sensors	Monitors voltage and current near the feeder breaker and store measured data offsite.	These are installed on most of MP's substations that do not have SCADA to gather better data and eliminate manual reads. At the end of 2024, 133 distribution feeders (40%) had smart sensors installed near feeder source.
Manual meter reading	Occasionally collected by operations personnel during substation inspections.	These readings collect peak amp data every month and are reset after each reading.
Advanced metering infrastructure (AMI)	Used for the vast majority of meter collection systems.	The AMI system records voltage, kW, kilowatt-hours, kilovar-Hour, click counts and informs the outage management system of customer outages and restoration. The AMI system collects 15 minute-interval usage data.

[16] *Id.,* at 14-15.

2. Advanced Metering Infrastructure

The Company emphasized that its current AMI system was fully deployed as of 2023 and is integrated with other operational software systems.[17] AMI enabled advanced Time-of-Day (TOD) rates when combined with a meter data management system (MDM). Minnesota Power received Commission approval in 2023 to transition to a formal AMI opt-out process for residential customers, where residents opting out of the program would pay a monthly fee for the manual reading and maintenance of the meter. Below is a timeline provided by the Company of its AMI meter installments.[18]

The Company noted that it has begun the deployment of next generation AMI infrastructure in 2025 and over the next several years as meters from the initial deployment near end-of-life.[19]

3. Grid Modernization

For each grid modernization project, the Company is required to provide a cost-benefit analysis (BCA).[20] Minnesota Power's five-year action plan includes a grid modernization budget containing FLISR implementation and the Kerrick BESS pilot project.

Minnesota Power explained that: "A case-by-case approach is needed to focus resources on projects with the highest potential for deferral or grid benefits such as reliability or resiliency, ensuring that BCA efforts are targeted, meaningful, and aligned with system planning priorities.[21] Broad application of a detailed BCA across all projects would result in diminishing returns and unnecessary administrative burden."

Moreover, the Company noted that it is in the process of introducing a multi-year plan to install smart switches ("Intellirupters" and logic enhanced reclosers) and the accompanying communication system in various locations on the distribution system.[22]

MP detailed its proposed pilot programs below:[23]

Load Flexibility: Minnesota Power is exploring increasing the offering of load flexibility program for customers through its ECO program. The Company is also exploring the aggregation of these load flexibility programs with DERs, including customer-sited storage and demand response, effectively creating a virtual power plant (VPP) on the distribution system.[24]

[17] *Id.*, at 15.
[18] *Id.,* at 16.
[19] *Id.,* at 64.
[20] Petition, at 76.
[21] *Id.,* at 77.
[22] *Id.*, at 63.
[23] *Id.,* at 68-70.
[24] *Id.,* at 69-70.

Advanced Fault Location, Isolation and Service Restoration (FLISR): Minnesota Power is exploring a Centralized Radio Recloser (FLISR) pilot which would expand upon the current Radio Recloser FLISR pilot. It stated that the Centralized Radio Recloser FLISR could offer cost savings in suburban and rural areas by avoiding the fiber infrastructure expansion needed to accommodate more Intellirupter deployments. The Company stated that the pilot should also allow a more rapid expansion of system visibility, reliability improvement, and wildfire mitigation efforts.

Conservation Voltage Reduction (CVR): the Company is considering the implementation of a CVR/VVO (Volt-Var Optimization) pilot in future years. Implementing this system would require additional equipment which would lead to additional capital spending and long-term operation and maintenance costs. The Company noted that the success of this system depends on the AMI.

Hosting Capacity Analysis: In addition, Minnesota Power mentions that while it does not perform hosting capacity analysis (HCA), it is moving towards doing so through its engagement in the EPRI DRIVE[25] User Group and the new Synergi Distribution Planning software that it adopted in 2022 which includes an integrated hosting capacity tool.[26] The Company hopes to have working Synergi models by the end of 2025.[27]

The Department noted that it supported all of MP's pilot projects and expected the results of the implemented projects to appear in the 2027 IDP.[28]

The Department had recommended that the Commission require MP to report on the actual reliability benefits and costs of the projects in MP's grid modernization category in the next IDP. However, after MP pointed out that the information is reported in the 2025 IDP in section 7, the Department withdrew the recommendation.

C. Capacity

Minnesota Power considered capacity and reliability to be inherently interrelated categories, wherein the Company makes system upgrades for capacity and reliability to address load-serving capacity or customer reliability issues.[29] For instance, if Minnesota Power identified voltage or capacity issues are identified because of load growth on a circuit, the Company may need to reconductor a portion of a circuit to ensure continued reliable service. Additionally, the Company noted that its upgrades for system capacity or reliability overlap with its Asset Renewal and its Grid Modernization categories. For example, "a project with a strong reliability component, such as reconductoring a section of feeder to a tie switch to ensure adequate

[25] Electric Power Research Institute (EPRI) Distribution Resource Integration and Value Estimate (DRIVE). This is a tool for the Company to gain understanding of hosting capacity analysis requirements to perform an HCA study.

[26] Petition, at 56-57.

[27] *Id.,* at 56.

[28] Department initial comments, at 26.

[29] Petition, at 61-62.

backup capability for planned or unplanned outages, might also increase the capacity of the feeder."

1. Right-Sizing Equipment

Right-sizing distribution system equipment refers to the practice of planning and designing distribution assets, such as substations, to provide the right amount of capacity to match expected load, without oversizing or undersizing such assets. Oversizing can lead to excess, underutilized capacity that increases costs for ratepayers in the near term while undersizing can necessitate more substation upgrades in the long term, also increasing costs for ratepayers.

The Department noted that since the majority of MP's substations had significant headroom capacity, the median utilization rate being 37.5%, MP's substations were largely oversized.[30]

The Department noted that while it did not appear that MP oversized its substations based on forecasted load, equipment ratings could only explain some of the excess capacity. The Department sought more information from MP in reply comments to explain the oversizing of its substations.

The Department explained that oversizing equipment can protect against future upgrades but can also increase near-term costs since larger assets are more costly. Since the best time to right-size equipment is during asset replacement, the Department highlighted that the asset replacement process in MP's budget could be the best chance to right-size old equipment (that may never be fully utilized) and "spare MP's ratepayers from significant impacts that are expected from MP's Age-Related Replacements and Asset Renewal budget."

MP disagreed that its systems are oversized and stated that it sizes its systems based on its system reliability and operational needs. MP noted that it utilizes power flow studies to identify the maximum loading on distribution assets as well as contingency analyses to determine their ability to provide backup power capability with an adjacent feeder. The Company explained that it uses standard sizes across its system assets when applicable for system efficiency.

The Department remained concerned about MP's substation oversizing.[31] The Department noted that it does not see why the Company's N-1 capacity conditions (37.5% utilization) are significantly different from those of Xcel (58.4%) or Dakota Electric (74.6%).

The Department noted that MP's response does not explain the difference in substation transformer capacity utilization. The Department stated that it may seek further analysis from the Company concerning its winter capacity ratings, emergency ratings, and N-1 redundancy.

30 Department initial comments, at 17-19.

31 Department reply comments, at 11-13.

2. Capacity Planning Standards

The Department concluded from MP's response to its IR that MP does not conduct robust forecast accuracy checks.[32] The studies happen irregularly and are reactive to grid needs and issues. In addition, the Department stated that "MP confirms that it does not evaluate its N-1 contingency mitigations for cost effectiveness, and its irregular distribution planning study process ensures that mitigation of capacity risks may go unnoticed for years until a targeted distribution planning study is performed."

However, the Department highlighted that despite the gaps in forecast accuracy and inconsistent review of MP's distribution capacity needs, the Department did not currently see a need for further capacity planning standard review since capacity is not a significant driver of distribution mitigations. The Department noted that it would re-evaluate the need for further capacity planning standard review in MP's next IDP.

D. Reliability

1. Strategic Undergrounding

Minnesota Power noted in the IDP that strategic undergrounding was a core part of its reliability and resiliency efforts.[33] The Company elaborated that it targeted areas where vegetation management was difficult to access, such as with tree pruning. Moreover, the main drivers of strategic undergrounding were reliability improvements, storm resiliency, overhead conversions in response to aging assets, costs of O&M vegetation reduction, reduction in trouble costs as reliability improves, and aesthetic purposes. Minnesota Power prioritized its undergrounding locations according to feeder reliability, vegetation management costs, maintenance accessibility, and soil type and conditions in the area.

The Department saw MP's strategic undergrounding initiative as a targeted approach focused on specific physical conditions and reliability outcomes instead of a uniform system-wide conversion strategy.[34] The Department noted that strategic undergrounding "can significantly reduce exposure to tree contact, wind-driven debris, and other storm-related hazards that are associated with overhead construction in heavily vegetation areas."

The Department emphasized that strategic undergrounding is reasonable if narrowly applied to the segments that lead to high outage minutes and where site conditions limit the effectiveness, or cost-effectiveness, of other mitigation measures.

However, the Department stated that MP's strategic undergrounding approach in the IDP is largely qualitative and does not have the quantitative data necessary to evaluate the cost-

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[32] Department initial comments, at 11-12.

[33] Petition, at 61-62.

[34] Department initial comments, at 12-13.

effectiveness of such an approach.[35]

As a result, the Department recommended the Commission require the Company to develop clear reporting metrics for its reliability projects (e.g., miles converted, segments addressed) and provide a clear methodology for selecting segments in their distribution system (**Decision Option 5**). The Department noted that MP did not have a standard monetized value assigned to calculate the savings derived from reducing customer minutes out (CMO).

MP agreed with the Department's recommendation to develop clearer reporting metrics and noted that in the future, it would add additional inputs for its distribution asset evaluation framework, such as wildfire risk.[36]

Additionally, the Department highlighted that MP mentioned other reliability tools that can be evaluated as alternatives to strategic undergrounding.[37] For instance, equipping feeders with TripSavers or IntelliRupters leads to a drop in SAIDI minutes. Therefore, the Department recommended that strategic undergrounding should be evaluated along with other reliability tools to help reduce outage minutes on targeted feeders (**Decision Option 6**).

The Company agreed with the evaluation of strategic undergrounding alongside other reliability tools.

2. Value of Reliability

Department recommended that the Commission require MP to quantify the value of major reliability and resiliency investments, such as strategic undergrounding, using a recognized customer interruption cost approach (e.g, an Interruption Cost Estimate [ICE] calculator methodology) and to apply that value consistently in cost-benefit comparisons across alternatives (Decision Option 3).[38] The Department noted that its recommendation was consistent with Xcel Energy's 2025 IDP, which uses the Lawrence Berkeley National Laboratory ICE calculator.

In response, MP proposed a modification, recommending that the Company be allowed to work with the Department and other interested stakeholders to evaluate options for quantification tools.[39] In the same vein, MP also proposed that the Commission consider phased implementation of the ICE calculator or similar tools rather than an immediate mandate. MP reasoned that since "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."

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35 *Id.,* at 13-15.

36 MP reply comments, at 10-11.

37 Department initial comments, at 15.

38 Department initial comments, at 14.

39 MP reply comments, at 11.

Additionally, the Department found it necessary to discuss how best to assess the value of reliability.[40] The Department noted that "three out of the four rate-regulated utilities do not quantify the value of reliability, and therefore do not know whether their reliability projects are cost effective." The Department remarked that outstanding questions remain regarding the appropriate cost of unserved energy, potential cost caps for reliability benefits, forecasting reliability benefits, use cases for a value of reliability, and how to valuate reliability by customer class. The Department reasoned that these topics merit further discussion within a new comment period following this current round of IDPs.

The Department recommended that the Commission delegate authority to the Executive Secretary to issue a Notice of Comment Period in each IDP docket to discuss the appropriate value of reliability. The Department recommended that the notice topics address: The valuation of the cost of unserved energy

- The use of price caps for the cost of unserved energy
- Forecasting methodologies for reliability benefits
- Appropriate uses cases for the value of reliability
- The potential to employ different values of reliability by customer class

(**Decision Option 7**)

In addition, the Department agreed with MP's proposed modification to the Department's recommendation for a phased implementation of an ICE calculator method or similar approach in consultation with the Department and other stakeholders (**Decision Option 9**).[41]

a. *Staff Analysis*

As discussed in the Joint Briefing Papers, the Department has made similar recommendations related to the value of reliability across all four IDPs. As an alternative to the Department's recommendation, Staff suggests holding a technical workshop with LBNL to learn about nationwide best practices prior to requiring utilities to develop methodologies for quantifying the value of reliability improvements (**Decision Option 8**).

E. Wildfire Mitigation

Minnesota Power stated that it will develop a wildfire risk mitigation plan in four stages:[42]

1. Developing a Wildfire Risk Map: the Company is developing risk factors including vegetation information, fuel loading, wild-land urban interface areas, etc. to indicate hazardous fire areas on a landscape/population wildfire risk map.
2. Developing a Wildfire Risk Model: the Company aims to use the wildfire risk map to help inform the model.
3. Calibrating and implementing a Fire Potential Index (FPI): the FPI is a situational

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[40] Department reply comments, at 6-8.

[41] *Id.*, at 8-9.

[42] Petition, at 67-68.

awareness tool to inform and support field mitigation planning and operational decision-making.

4. Wildfire Mitigation Plan: the Company would evaluate its current plan based on the previous three stages.

Minnesota Power included a budget of approximately $500,000 in its 5-year action plan to develop the wildfire mitigation plan.

1. Department Initial Comments

The Department stated that it was supportive of MP's phased approach to wildfire mitigation, which began with mapping and identifying high risk areas within MP's service territory.[43]

The Department had recommended that the Commission require MP to file a compliance filing in this docket after phase one of MP's wildfire mitigation plan development is complete. The filing would have included the results of phase one of its Wildfire Mitigation Plan, including the Company's wildfire risk map and its methodology, its identified hazardous fire areas, a timeline for the remaining phases, and a proposed budget relating to continued development of the plan.

Proper Venue

Furthermore, the Department expressed its concern regarding the lack of record development on wildfire mitigation spending ahead of cost recovery proceedings. The Department cautioned that without a docketed location for the review of wildfire mitigation proposals, the only review may occur when MP files for cost recovery, which can further constrain stakeholders' time and resources across a range issues. The Department asserted that the contested case arena should not be where stakeholders learn of and analyze potentially complex, costly proposals for the first time and that instead, the IDP could be the venue for a better review of wildfire expenditures ahead of rate recovery.

The Department noted its appreciation for the Company's North Dakota Wildfire Mitigation Plan and suggested that a future wildfire mitigation filing could model the North Dakota plan while including additional information on the Company's current processes, measures, and proposals for wildfire mitigation.

As such, the Department recommended that the Commission require Minnesota Power to file its future Wildfire Mitigation Plan with the Commission as an attachment or supplement to its IDP, and recommended several reporting requirements for the Company to satisfy. (**Decision Options 10** and **12**).

2. Minnesota Power Reply Comments

MP stated that it planned to complete its WMP by mid-year 2026 but did not foresee

43 Department initial comments, at 22-24.

completing development of its WMP investment strategy before the next IDP filing in 2027.[44]

In response to the Department's two initial recommendations**,** MP requested 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.[45]

MP reasoned that as it already envisioned including a finalized WMP in its next 2027 IDP filing that would be designed as a "single, interrelated, and iterative four-phased framework rather than a series of independent phases", a formal compliance filing at the end of phase one would have only provided an incomplete view of the Company's WMP.

Additionally, MP noted that its customers have not faced wildfire-related outage to date, which means that it lacked historical data to perform CBAs. It noted that for the purpose of 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."

MP argued that since wildfire risk was statewide and interconnected, evaluating WMPs only within the IDP could risk a siloed approach 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")."

In addition, MP levied that because wildfire mitigation strategies were 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.

3. Department Reply Comments

The Department subsequently withdrew the recommendation that MP file a compliance filing in the IDP docket after the first phase of its WMP development was complete.[46] The Department recognized that "the interrelatedness of MP's WMP development process and the limited amount of time between a potential order in the present IDP and the next filing date, could make effective review of a compliance filing complicated." It noted that while an initial review of the wildfire map could alleviate future workload, it is not entirely necessary.

However, the Department maintained and modified its following recommendation that MP file a WMP as an attachment or supplement to its next IDP and include several elements.[47]**.** The

[44] MP reply comments, at 7.

[45] *Id.*, at 8-9.

[46] Department reply comments, at 13-14.

[47] *Id.,* at 15-16.

Department noted that MP did not respond to the merits of the elements of the recommendation but disagreed with filing the WMP in the IDP docket or in the IDP itself. Although the Company argued that evaluating the WMP in the IDP would silo the analysis, given the statewide and Company-wide impacts across generation, transmission, and distribution, the Department contended that stakeholders can still involve themselves in different topics of the IDP process as much as their expertise and bandwidth allow for.

Outside Contractor

Moreover, the Department highlighted that since WMPs are quite new for planning dockets and regulatory review, hiring an outside contractor could improve the review process of each utility's WMP by bringing in additional outside insight not in-house at the Department; the Department estimated that the services of the contractor over a 2-year period would total up to $300,000 (**Decision Option 13**).[48] "The Department estimates these costs in the context of the costs incurred for contractual services in Xcel and OTP's ongoing rate cases to review proposed wildfire expenditures."

4. Staff Analysis

As noted in the Joint Briefing Papers, Staff recommends that WMP take place in a separate proceeding (**Decision Option 11**) instead of as part of the IDPs (**Decision Option 10**).

F. Distributed Energy Resources

According to the updated IDP filing requirements approved in the Commission's notice, DERs in the context of the IDP process refer to "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers and can be installed on either the customer or utility side of the electric meter" including battery energy storage systems (BESS), energy efficiency programs, distributed solar, demand side management (DSM) programs, and heat pumps.[49]

1. Distributed Generation

Customer Solar: Minnesota Power's SolarSense program has been in place since 2004 and was most recently extended for three years by the Commission through 2027.[50] The extension modified the program to include an income cap of 150% of area median income as well as a preference for federally designated disadvantaged communities. So far, the program has supported 534 solar installations.

Community Solar: the Company's Community Solar Garden (CSG) Pilot Program consists of a 1 MW solar array in Wrenshall, Minnesota and a 40 kW solar array in Duluth, Minnesota.

Distributed Solar Energy Standard (DSES): Minnesota Power has met the small scale solar carve-

48 *Id.*, at 16-17.

49 *Id.,* at 23.

50 *Id.,* at 26-27.

out of the Solar Energy Standard (SES) requirements and aims to reach compliance with the DSES.

2. Load Management

Industrial Demand Response: Minnesota Power has around 230 MW of MISO-accredited demand response from its large industrial customers.[51]

Dual Fuel: the Company offers a Dual Fuel rate that allows the Company to curtail mainly heating load of around 8,000 residential, commercial, and small industrial customers during times of high market energy prices or to avoid a system peak. The Dual Fuel rate currently applies to several electric end-uses, including electric heat, electric water heating, EV chargers, hydronic/resistive in-floor heat, etc.

Time of Day (TOD) Rates: on August 27, 2021, Minnesota Power received Commission approval to transition its residential customers from Inverted Block Rates (IBRs) to TOD rates. In 2026, the Company would begin the third phase of the evaluation process of the TOD to assess its impact.

3. Energy Conservation

Historically, Minnesota Power has achieved an average of 74 gigawatts hours (GWh) of incremental annual energy savings.[52] The Company achieved 76 GWh in savings in 2024. From 2017 onwards, the Company was required to report peak demand savings from the Energy Conservation and Optimization (ECO) program coincident with the MISO system peak. The average peak demand savings from 2017-2024 was 7.5 MW. Minnesota Power includes a table below showing the savings:

Table 2: Average Total Savings

	Reported MW Savings at Generator	Total MWh Savings	Percentage Savings
2013	5.72	77,631	0.025
2014	9.22	76,338	0.025
2015	7.23	85,611	0.028
2016	9.49	64,034	0.021
2017	8.59	72,372	0.026
2018	8.1	72,480	0.026
2019	8.34	67,669	0.025
2020	6.81	70,774	0.026
2021	6.83	74,539	0.028
2022	8.2	76,400	0.029
2023	7.07	73,589	0.028
2024	5.94	76,583	0.030

[51] *Id.,* at 29-32.

[52] *Id.,* at 33-34.

4. Electrification

Minnesota Power stated that it would submit a modification of its ECO portfolio to add an efficient fuel switching (EFS) program by the end 2025.[53] If approved, the Company's customers without an electric baseline would be eligible for rebates on the following equipment

- Air to water heat pumps
- Air source heat pumps
- Desuperheaters
- Electric vehicles
- Electric bicycles
- Ground source heat pumps
- Heat pump water heaters
- Outdoor lawn equipment

5. Electric Vehicles

Minnesota Power noted that EV adoption is minimal in northern Minnesota due to the lack of public charging infrastructure, range anxiety, and upfront cost of purchasing an EV.[54] The Company stated that according to the Commission's vehicle registration data pushed on July 7, 2025, there are 1,105 EV owners in the Company's service territory, of which 730 are battery electric vehicles (BEVs) and 375 are plug-in hybrid EVs (PHEVs). The Company estimated that there are 825 light-, 22 medium-, and 9 heavy-duty EVs in its service territory.

Moreover, Minnesota Power noted that there are 74 public EV charging stations in its service territory and that it is expanding the availability of public EV chargers through its direct current fast charger (DCFC) project.

The Company offers three EV charging rates and provides a table below detailing the participation in these rates for the reporting period from May 1, 2024, to April 30, 2025:

Table 3: Minnesota Power EV Rates

	Number of Participating Customers	**Energy Consumed (kWh)**
Residential EV Service	64	277,460
Fleet EV Rate	1	34,327
Public EV Rate	21	1,655,966

[53] *Id.,* at 36.

[54] *Id.,* at 37.

6. Battery Storage

Minnesota Power noted that there is currently one battery energy storage system (BESS) being developed on its distribution system: a 2.5 MW/5 MWh BESS near Kerrick, MN.[55] All major equipment should be installed in 2025. In addition, while the Company's customers can install BESS behind-the-meter, these systems do not export energy to the grid. The Company envisioned the delivery of the project by late 2025 and full implementation in 2026.[56]

7. Barriers to DER Integration

FERC Order 841 removed barriers to the participation of electric storage resources in RTO/ISO wholesale markets.[57] Minnesota Power noted that FERC Order 841 poses challenges to interconnection of distribution-level BESS and DERs due to the participation of DERs in wholesale RTO/ISO markets impacting local distribution operators.

G. Load Forecasting and Scenario Analysis

Minnesota Power describes its 2025 Annual Forecast Report (AFR) that includes assumptions for residential and commercial adoption of DERs and well as the impact of DERs on sales.

The Company's AFR methodology relies on solar DG installations projections by the U.S. Energy Information Administration.[58] Minnesota Power combines this forecast of new installations with its assumptions for the kW capacity of the new installations, an expected capacity factor, and seasonal production characteristics to produce monthly estimates of energy production and peak reduction. The energy sales and peak demand forecasts are adjusted for new installations while currently installed DG systems are considered embedded in the forecast.

1. Distributed Solar Generation:

Below the Company provides a graph of the base, medium, and high cases of commercial and residential solar DG installations according to its 2025 Annual Forecast Report.[59]

55 *Id.,* at 43-44.

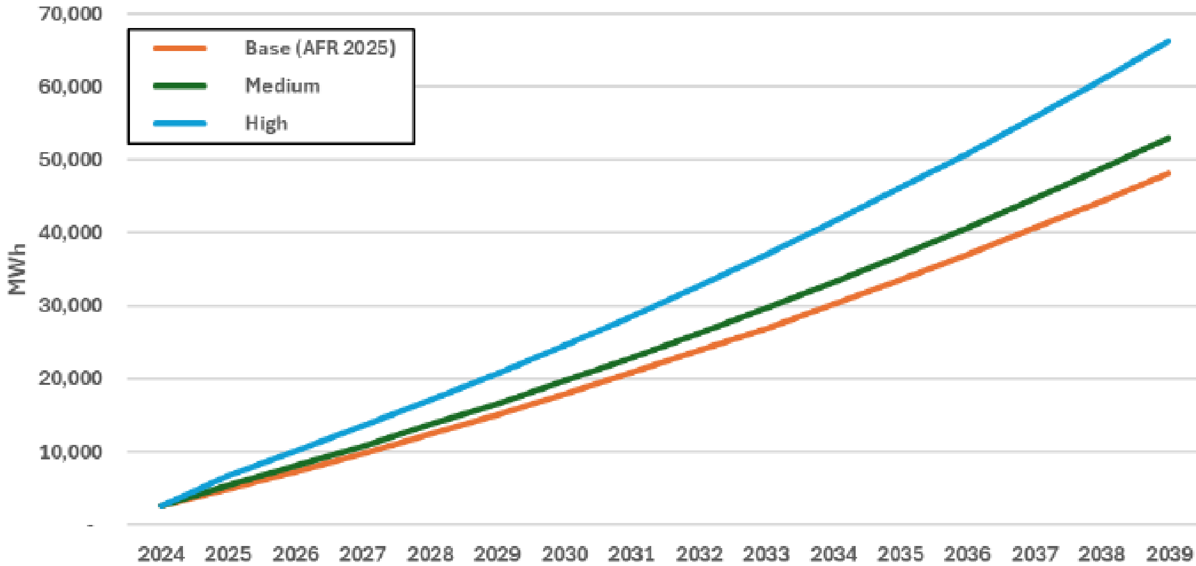
56 *Id.,* at 77.

57 *Id.,* at 44.

58 *Id.,* at 45-46.

59 *Id.,* at 46.

Figure 4: Distributed Solar Generation (MWh)

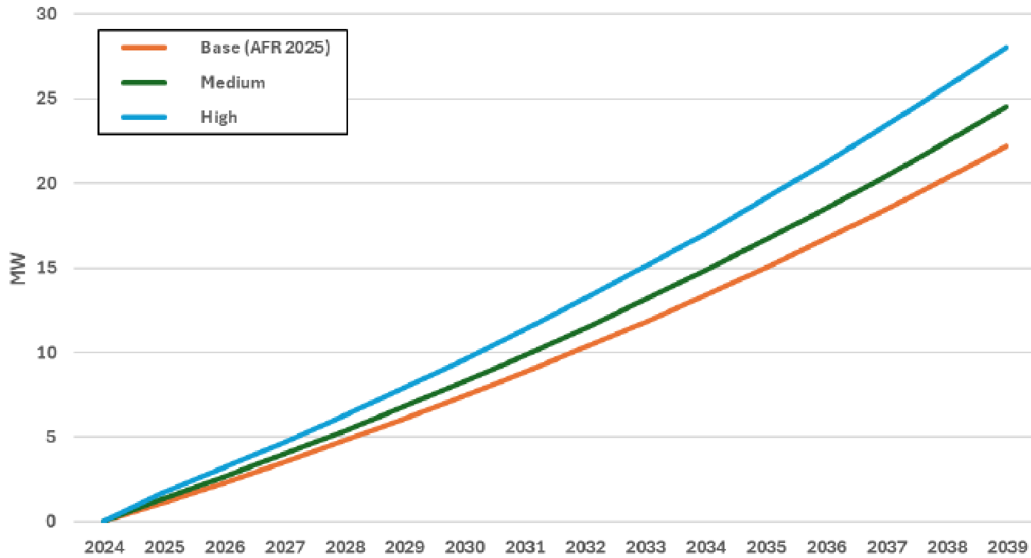


The Company made the following assumptions in each of its cases:

- Base Case: The Company's Base Case forecast assumes about 4,180 new small-scale DG Solar installations, adding almost 46,000 KW of nameplate capacity, which will be connected to Minnesota Power's distribution system by 2039 (i.e. installed in years 2025- 2039). These new installations would generate about 46,000 MWh per year and reduce sales to residential and commercial sectors by an equivalent amount. The Base Case forecast assumes cumulative capacity expands at a 21.6% compound annual growth rate ("CAGR") from 2025 to 2039.
- Medium Case: The Medium DER scenario applies a 10% growth rate to the Base Case's cumulative capacity and results in an overall cumulative small-scale solar capacity CAGR of about 22.4% from present installed capacity to projected 2039 capacity.
- High Case: applies a 25% growth rate to the Base Case, resulting in a CAGR of about 23.4% over the same period. The following graph shows the reduction in the Company's summer peak demand due to the solar DG generation.[60]

60 *Id.,* at 47.

Figure 5: Distributed Solar Generation (Summer Peak)



2. Light-, Medium- and Heavy-Duty Electric Vehicle Forecast:

Minnesota Power estimated that there are around 825 light-, 22 medium-, and 9 heavy-duty vehicles in its service territory, indicating 3,262 MWh of yearly energy consumption and representing 0.15% of all residential and commercial energy sales.[61]

In the Company's base case, it projected that, by late 2039, EVs will consist of approximately 43% of regional vehicle ownership across all weight classes, and Minnesota Power will be the primary electric service provider to about 95,400 EVs.[62] This equates to about 395,000 MWh in additional energy requirements from the residential and commercial sectors and an estimated increase of 44 MW and 131 MW in the summer and winter peaks (respectively).

Below are Minnesota Power's graphs indicating the winter and summer peak impacts by EVs:[63]

[61] *Id.,* at 47-48.
[62] *Id.,* at 48.
[63] *Id.,* at 51.

Figure 6: EV Winter Peak Impact (MW)

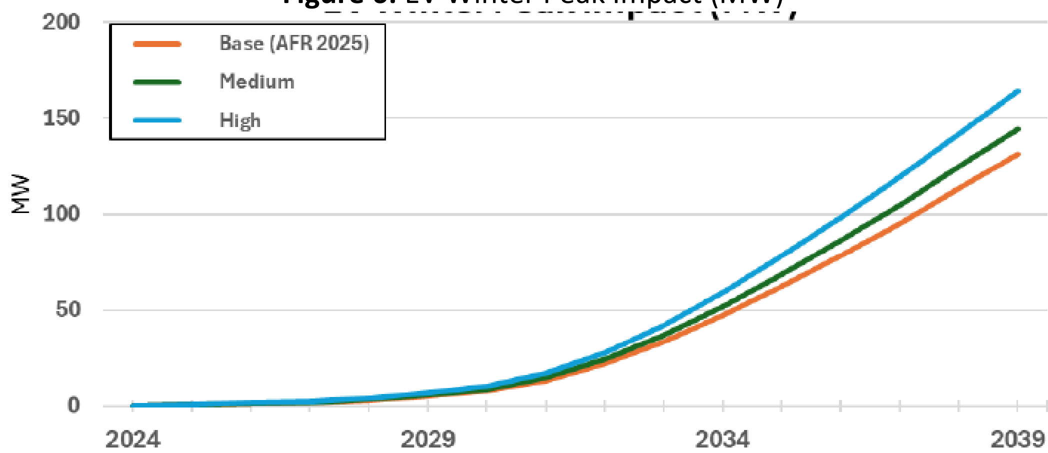
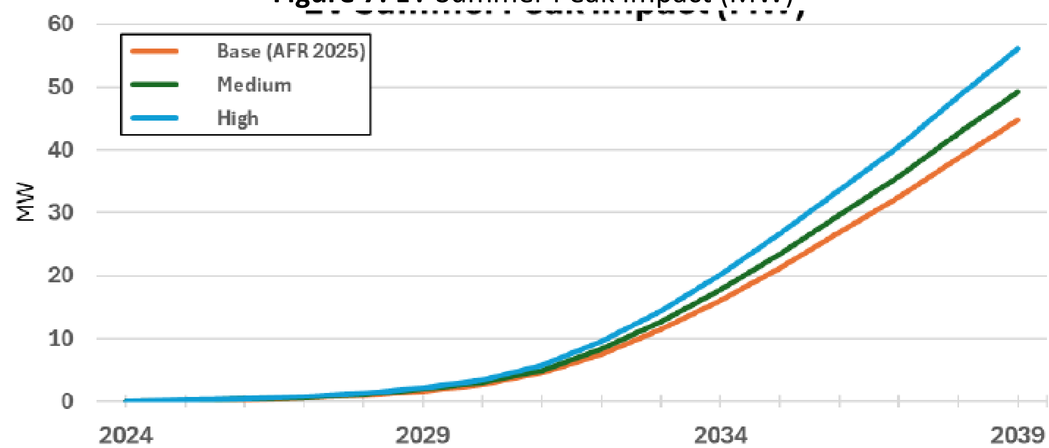


Figure 7: EV Summer Peak Impact (MW)



3. Electrification

Minnesota Power noted that it will begin to monitor electrification load adoption as it develops and implements efficient fuel switching programs as part of the ECO portfolio.[64]

H. Non-Wires Alternatives Analysis

Non-wires alternative (NWA) analyses are required for any capital distribution project over $2 million. Minnesota Power noted that NWA analyses are appropriate for when the solution is not addressing an asset renewal need and for when the operational characteristics of the NWA solution adequately corresponds to the need.[65]

Minnesota Power has 18 proposed large distribution projects (above $2 million) NWA analysis within its five-year capital distribution plan.[66] These projects are part of two categories: Age-Related & Asset Renewal and Reliability & Power Quality. 12 of 18 projects fall into the first

64 *Id.,* at 54.

65 Petition, at 71.

66 *Id.,* at 73-74.

category while the remaining 6 projects fall into the latter category. The Company noted that none of these projects are eligible for NWA analysis, as the former 12 of 18 projects address an asset renewal need while the latter 6 of 18 projects address customer reliability or backup capability.

1. Department Initial Comments

The Department expressed its uncertainty with whether MP complied with the Commission's 2023 IDP Order point[67] requiring that MP "consider demand response, energy efficiency, and renewable generation as part of its future Non-Wires Alternatives process."[68] MP's response mentioned the use of advanced software platforms to address this order point, which the Department stated did not specifically address the specific resources outlined in the Order.

2. Minnesota Power Reply Comments

MP noted that all scenarios in the 2023 NWA 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").[69]

MP appreciated the Department's mention of pairing distributed solar with NWA solutions as part of meeting the statutory Distributed Solar Energy Standard (DSES)[70]. The Company stated that it issued its first DSES RFPs on January 30th, 2025, and is undergoing project selection.

Moreover, MP noted that it faces challenges in leveraging demand response programs for NWA objectives. Specifically, customer participation, equipment, and behavior can change without notice, it is 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."

3. Department Reply Comments

The Department found that MP fulfilled the Commission's 2023 IDP Order point for MP to explain how it has considered demand response, energy efficiency, and renewable generation in its NWA analysis.[71]

I. IDP Acceptance and Process

Minnesota Power and the Department both recommend acceptance of the Company's 2025

67 Docket No. E015/M-23-258 (eDockets), *In the Matter of Minnesota Power's 2023 Integrated Distribution Plan*, Department, Comments, April 5, 2024, at 7.

68 Department initial comments, at 27-29.

69 MP reply comments, at 6-7.

70 Minn. Stat. §216B.1691, subd. 2h (2024), (hereinafter "the DSES statute").

71 Department reply comments, at 18-19.

IDP (**Decision Option 1**).

As discussed in the Joint Briefing Papers, since their inception IDPs have grown and scope, which has strained stakeholder resources. The Department recommended staggering the filings to help alleviate this issue. Staff recommends having Minnesota Power, along with Dakota Electric and Otter Tail Power, file its IDP and TEP in even numbered years with the next filing due in 2028 (**Decision Option 2**).

Staff also recommends the creation of a standing IDP Improvement Workgroup for Minnesota Power, as discussed in the Joint Briefing Papers (**Decision Option 3**).

IV. Transportation Electrification Plan

In its most recent Transportation Electrification Plan (TEP), MP highlighted its ongoing EV programming which includes charging infrastructure, rates, rebates, and education programming. In 2026 MP plans to implement its make-ready multi-dwelling unit (MDU) pilot, L, and build out an electrician network to support charger installation education and workforce development regarding EV best practices.[72] Along with the make-ready programming, the Company continues to install its DCFC stations to alleviate range anxiety across its Minnesota service area.[73] The Company also has multiple rates for residential and commercial customers to provide EV specific rate and time of day rate options for charging.[74]

MP noted, per Atlas Public Policy, there are 74 public EV charging stations with 134 level 2 and 88 DCFC charging ports.[75] The Company saw an increase in stations participating in their commercial public EV charging rate since their last TEP, increasing from 13 to 17.[76] While the Company has not seen a large shift in medium and heavy duty fleet conversions, the Company offers information to fleets to encourage conversion. During this TEP period, the Company provided informational services to two fleet operators, one of which implemented changes to its fleet and engaged with the Company's commercial public charging rates.[77]

MP also focused on education and outreach programming to engage with multiple partners in a multitude of community settings including EV event sponsorship, customer presentations, and community festivals.[78]

MP began offering Level 2 charger rebates in 2021, and this year will be expanding its rebate programming to include EVs and e-bikes via its current ECO triennial plan.[79] The Company is

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72 Petition, Appendix E, at 6.

73 *Id.,* at 7-8.

74 *Id.*

75 *Id.,* at 11.

76 *Id.,* at 12.

77 *Id. ,*at 15.

78 *Id.,* at 19.

79 *Id.,* at 8.

also evaluating two programs for ECO inclusion for its upcoming triennial plan to target medium and heavy-duty fleet electrification. The goal is to provide an analytics conversion tool to help operators and fleet managers determine which vehicles in its fleet would be the most appropriate to convert based on factors such as utilization rates, costs, and sustainability objectives.

The second program would be to support electric school buses to improve local air quality, reduce GHG, and provide vehicle-to-grid benefits.[80] In support of that program, the Company consolidated its information to create an online school hub to provide resources for schools that direct schools to electric school bus funding resources.[81]

With regard to MP's equity considerations in transportation electrification planning, the Company engaged and continues to engage with the Upper Midwest Inter-Tribal EV Charging Community Network which specifically supports the installation of DCFC on reservations as well as level 2 chargers at community hubs.[82] The Company also highlighted its new make-ready pilot as it is focused on MDUs. That program provides greater weight to applications that are from income-qualified housing.[83]

<u>Company-Owned Direct Current Fast Charging</u>

Minnesota Power is installing 16 company owned DCFC stations its service territory ranging from 50 kW to 350 kW in capacity.[84] MP estimated that the 16 DCFC stations will add about 3,500 MWh of energy use by 2030 and contribute about 0.6 MW to Minnesota Power's 2030 summer peak. By 2039, the 16 DCFC EV charging stations would add about 54,000 MWh of annual energy use and about 8 MW to summer peak demand.

1. <u>Department Initial Comments</u>

The Department reviewed the Company's TEP per the requirements in Minn. Stat. § 216B.1615, Subd. 3. Ultimately the Department recommended that the Commission approve the TEP with recommendations to strengthen reporting surrounding EV accessibility issues. (**Decision Option 15**)**.** However, the Department expressed concern that the Company is not fully addressing equity and EV accessibility issues as required by Minn. Stat. § 216B.1615, Subd. 3(2).[85] The Department noted that there was little measurement of equity reach in the Company's EV portfolio beyond narrative discussions. With that, the Department recommended that the Commission require the following pieces of information in future TEPs reporting requirements (**Decision Option 21**):

1. The percentage of its commercial sites located in areas disproportionately impacted by transportation pollution, broken out by commercial program.

80 *Id.,* at 23.

81 *Id.*

82 *Id.,* at 24-25.

83 *Id.,* at 25.

84 Petition, at 52.

85 Department initial comments, at 40-41.

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.

MP committed to analyzing the proposed Department metrics to the greatest extent possible but noted the Company believes that several of them presented challenges to collect data or maintain privacy considerations. Alternatively, the Company proposed collaborating with interested parties to identify reasonable proxies to ensure metric intent if the metric cannot be met without undue burden (**Decision Option 21**).[86]

2. CEGs Comments

The Clean Energy Groups (CEGs) expressed concern that only 17 of the 74 public charging stations that exist in the Company's territory participate in the Company's Commercial Public EV Charging Rate and that only one of the two fleets that MP worked with engaged in the rate. To better understand the issue, the CEGs recommended a survey of commercial customers on how to improve and increase uptake of existing programs (**Decision Option 18**).[87] In reply, the Company stated they are surveying commercial customers to better understand the effectiveness of their programming and demand for fleet electrification.[88]

The CEGs also noted their continued support for a make-ready pilot that includes fleets. During the Company's proposal for their make-ready charging pilot last year, the commercial fleet portion was removed from the MDU make-ready pilot due to party feedback to the Company. The CEGs reiterated their position that the Commission should direct MP to file a fleet make-ready pilot and suggest it be a supplemental filing to their TEP (**Decision Option 16**).[89]

MP, in response to the CEGs recommendation, noted that it is currently implementing its make-ready pilot that was approved by the Commission and believes an expansion into fleets to be premature at this time. The Company noted that expansion would precede evaluation of the

86 MP reply comments, at 17.

87 Docket No. E111/M-25-141, *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Initial Comments of Fresh Energy, Union of Concerned Scientists, and the Environmental Law and Policy Center, March 13, 2026, (hereinafter "CEGs comments"), at 4.

88 MP reply comments, at 19.

89 CEGs reply comments, at 4.

existing pilot and could cause confusion among customers and trade allies.[90]

The CEGs also requested that the Commission direct MP to develop a program incentivizing grid optimized charging without the need for the installation of a second meter as a second meter creates a barrier to EV access (**Decision Option 17**).

The CEGs requested that the program be similar to Otter Tail Power's EVantage program (recently approved in Docket 23-380) which forgoes second service meter installation and allows the Company to actively manage the customer's charging load in exchange for a monthly bill credit.[91]

The Company did not respond to this CEG recommendation in its reply comment.[92]

The CEGs recommended that the Commission direct MP to develop more programming, specifically an electric carshare in their service territory as electric carshare programming has been successful in the Xcel service territory (**Decision Option 20**).[93] The Company stated they have analyzed and will continue to look into a similar program.[94]

3. Staff Analysis

As Minnesota Power has indicated it is already surveying commercial customers, Staff recommends requiring the Company to share the results of the survey with its next IDP (**Decision Option 19**) as an alternative to CEG's recommendation (**Decision Option 18**).

The CEGs reference the Evie/Hourcar carshare's success in the metro Twin Cities Xcel territory as an indicator of demand. However, Staff notes that the carshare program is extremely unique in nature and may not be replicable by a monopoly utility as the lead organization. The Evie/Hourcar organization did not start as an electric carshare and has significant from numerous partners including the cities of St. Paul and Minneapolis, Xcel, the McKnight Foundation, and other public private partnerships. Having a monopoly utility as the primary operator of a carshare program funded by ratepayer dollars would be a departure from traditional utility practice, and would require careful consideration by the Commission.

The CEGs requested that the Commission direct MP to include fleet advisory services and rebates for electric buses in their ECO triennial. Stakeholders provided recommendations asking the Commission to modify the ECO triennial programming in the current docket. While the Commission has required utilities to make certain programmatic filings in their triennials in the past, it has usually been with the support of the utility and with the Department of Commerce.

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90 MP reply comments, at 18.

91 CEGs reply comments, at 5.

92 MP reply comments, at 19.

93 CEGs reply comments, at 5-6.

94 MP reply comments, at 19.

V. DECISION OPTIONS

IDP Acceptance and Process

The Commission must select Decision Option 1 or reject Minnesota Power's IDP. It may also select Decision Options 2 and/or 3

1. Accept Minnesota Power's 2025 IDP Report as in compliance with IDP Filing Requirements and order points. Acceptance of the 2025 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3.
   (MP, Department)

2. Require Minnesota Power to file its next Integrated Distribution Plan and Transportation Electrification Plan on November 1, 2028 and every 2 years thereafter. Require Minnesota Power to file an interim update on November 1 of odd numbered years consisting of Baseline Financial Data (IDP Filing Requirements A.26-A.29).
   (Staff)

3. Delegate authority to the Executive Secretary to establish standing IDP Improvement Workgroup for Minnesota Power. Delegate authority to the Executive Secretary to approve via notice amended IDP filing requirements if agreement among stakeholders is reached.
   (Staff)

Age-Related Replacements and Asset Renewal

The Commission may select Decision Option 4

4. Require that MP conduct a cost benefit analysis 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 a realistic alternative baseline spending to MP's planned Age Related Replacements and Asset Renewal budget. The cost benefit analysis shall compare a realistic alternative baseline spending to MP's planned Age-Related Asset 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 IDP.
   (Department, MP)

System Expansion or Upgrades for Reliability and Power Quality

The Commission may select any combination of Decision Options 5 through 9.

5. Require that MP develop clear reporting metrics for its reliability projects (e.g., miles converted, segments addressed) and provide a clear methodology for selecting segments in their distribution system.
   (Department)

6. Require that MP evaluate strategic undergrounding alongside other reliability tools that can materially reduce outage minutes on targeted feeders.
   (Department, MP)

7. Delegate authority to the Executive Secretary to initiate a new proceeding to discuss the appropriate value of reliability. The initial comment period should address:
   a. The valuation of the cost of unserved energy;
   b. The use of price caps for the cost of unserved energy;
   c. Forecasting methodologies for reliability benefits;
   d. Appropriate uses cases for the value of reliability; and
   e. The potential to employ different values of reliability by customer class.

   (Department)

8. Delegate authority to the Executive Secretary to hold one or more technical workshops facilitated by Commission Staff on how to value reliability in distribution proceedings.
   (Staff)

9. Require that MP implement, on a phased basis, a process to quantify the value of major reliability and resiliency investments, such as strategic undergrounding, using a recognized customer interruption cost approach (e.g., an Interruption Cost Estimate [ICE] calculator methodology) or a similar recognized approach developed in consultation with the Department and other stakeholders, and to apply that value consistently in cost-benefit comparisons across alternatives.
   (Department, MP)

Wildfire Mitigation Plan

The Commission may choose Decision Option 10 or 11. If it does so, it should select Decision Option 12 and may adopt Decision Option 13.

10. Require Minnesota Power to file its Wildfire Mitigation Plan as an attachment or supplement to future IDPs, starting in 2028.
    (Department)

OR

11. Require Minnesota Power to file a Wildfire Mitigation Plan in a new docket by [insert date].
    (Staff)

12. Require Minnesota Power to include the following in its Wildfire Mitigation Plan:
    a. A description of the intent of the Company in mitigating wildfire risk (i.e. mitigating utility-caused wildfires/minimizing liability or mitigating fire damage to utility assets).
    b. A definition of “wildfire” as it is used for utility identification, planning and mitigation.
    c. A discussion of its risk modelling, mapping and project prioritization process within its Wildfire Mitigation Plan.

d. Quantification of actual wildfire risk in MP's territory based on the probability of a fire, and land use.
e. Wildfire risk should be compared to other reliability and safety risks experienced by MP as well as the wildfire risk experienced in MP's other jurisdictions.
f. Quantification of wildfire damages by event size, including MP-owned and other property damage, applicable liability, and any other costs MP deems reasonable to include.
g. The most recent version of its wildfire risk map with a narrative explanation of the highest risk areas, and any changes from the last iteration of the Wildfire Mitigation Plan.
h. Reporting on the number and location of wildfires experienced in its territory, the number of outages caused by wildfire, and the average length of wildfire-related outage over the last ten years.
i. Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the approved wildfire mitigation measures, wildfire-related outages in MP's territory decreased 50 percent; the average length of wildfire-related outage decreased by 20 percent.).
j. A full cost benefit analysis of any proposals.

(Department)

13. Pursuant to Minn. Stat. § 216B.62, subd. 8, request that the Commissioner of the Department of Commerce seek authority from the Commissioner of Management and Budget to incur costs up to $300,000 for specialized services to assist with any proceedings related to the review of wildfire mitigation plans for Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association.
(Department)

Transportation Electrification Plan

The Commission must select Decision Option 14 or 15, or reject Minnesota Power's TEP. The Commission may select any combination of Decision Options 15 through 21, with the exception of 18 and 19 which are alternatives.

14. Approve Minnesota Power's 2025 Transportation Electrification Plan.
(MP)

15. Approve Minnesota Power's 2025 Transportation Electrification Plan with the following modifications.
(Department, CEGs)

16. Require Minnesota Power propose a make-ready program for commercial fleets as a supplemental filing to this TEP.
(CEGs)

17. Require Minnesota Power to develop an actively managed electric vehicle charging program that does not require the installation of a second meter.
    (CEGs)

18. Require Minnesota Power to survey customers on how existing commercial offerings could be improved and increase uptake in existing programs.
    (CEGs)

OR

19. Direct the Company to share any quantitative and qualitative results, along with a summary and conclusion, of their current commercial EV survey with their next IDP due November 1, 2028.
    (Staff modification of CEG)

20. Require Minnesota Power to develop an electric carshare program in the Company's service territory.
    (CEGs)

21. Require Minnesota Power to report on the equity metrics as described by the Department of Commerce in their March 13, 2026 comments on pages 40-41. Direct Minnesota Power to work with interested parties to identify reasonable proxies if the metric cannot be met without undue burden. Require Minnesota Power to make a compliance filing with the list of finalized metrics with its November 1, 2027 interim IDP update and to begin reporting on the metrics with its next IDP due November 1, 2025.
    (Staff modification of Department and MP)