April 7, 2026 **PUBLIC DOCUMENT**

Sasha Bergman
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E017/M-25-141

Dear Ms. Bergman,

Attached are the **Public** comments of the Minnesota Department of Commerce (Department) in the following matter:

In the Matter of Otter Tail Power Company's 2025 Integrated Distribution Plan.

Otter Tail Power Company's (OTP or the Company) Integrated Distribution Plan (IDP) was filed on November 1, 2025. OTP's Transportation Electrification Plan was filed concurrently.

The Department recommends the Commission accept Otter Tail Power's IDP with modifications and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

AZ/RW/BP/DD/KB/ad
Attachment

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Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
CAIDI	Customer Average Interruption Duration Index
DER	Distributed Energy Resource
DOE	United States Department of Energy
ECO	Energy Conservation & Optimization
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location Isolation and Service Restoration
Grid Mod	Grid Modernization
IDP	Integrated Distribution Plan
IR	Information Request
IRP	Integrated Resource Plan
kV	Kilo Volt
kW	Kilowatt
kWh	Kilowatt-Hour
MP	Minnesota Power
MW	Megawatt
NWA	Non-Wire Alternative
O&M	Operations and Maintenance
OTP	Otter Tail Power Company
PUC	Public Utilities Commission
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TEP	Transportation Electrification Plan
Xcel	Xcel Energy

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E017/M-25-141

I. INTRODUCTION

Every two years, Otter Tail Power Company (OTP or the Company) submits an Integrated Distribution Plan (IDP), which began with the Minnesota Public Utilities Commission's (Commission) February 20, 2019 Order Approving Integrated Distribution Planning Filing Requirements for OTP.[1] The primary mechanism by which IDPs operate is compliance with the Commission's established filing requirements. The Commission accepts the IDP if it finds that OTP complies with its established filing requirements.

The Commission set forth five planning objectives for IDPs, with additional filing requirements to promote transparency in distribution system planning. The Commission's planning objectives for IDPs are to:

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.[2]

On February 26, 2026, the Department filed initial comments in Docket No. E002/M-25-142, Xcel Energy's (Xcel) 2025 Integrated Distribution Plan.[3] In those comments, the Department "advocates for an expansion of the review of Xcel's planning standards with a key objective to reduce Xcel's planned distribution spending."[4] Because Xcel faces a greater budgetary need for process change, the

[1] *In the Matter of Distribution System Planning for Otter Tail Power Company, Order Adopting Integrated Distribution Plan Filing Requirements*, February 20, 2019, Docket No. E017/CI-18-253, (eDockets) 20192-150449-02 (hereinafter "February 20, 2019 Order").
[2] *In the Matter of Otter Tail Power Company's 2025 Integrated Distribution Plan, Notice of Comment Period*, November 13, 2025, Docket No. E017/M-25-141, (eDockets) 202511-224922-01, at 2 (hereinafter "Notice").
[3] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan,* Department, Comments, February 26, 2026, Docket No. E002/M-25-142, (eDockets) 20262-228738-02, (hereinafter "Department Initial Comments on Xcel's IDP").
[4] *Id*., at 2.

Department intends to pilot the change in Xcel's distribution system planning rather than across the other utilities. The Department will assess the need for application to other utilities in the 2027 IDP.

II. PROCEDURAL BACKGROUND

December 8, 2022	The Commission issued its Order in Docket Nos. E002/M-21-694, E999/CI-17-879.[5] The Order approved combining the filing requirements of electric utility IDPs and TEPs.
May 2023	The Minnesota Legislature established requirements for utility TEPs in 2023 Minn. Laws. ch. 60, art. 12, sec. 12, codified at Minn. Stat. § 216B.1615 – Electric Vehicle Deployment Program. Minn. Stat. § 216B.1615 requires electric utilities to file TEPs, established certain content requirements, granted the Commission authority to approve, modify or reject TEPs, and established evaluation criteria.[6]
August 23, 2023	The Commission issued its Order Accepting Withdrawal of Clean Transportation Portfolio Subject to Conditions. The Order placed a number of conditions upon Xcel Energy, including that it file a TEP by November 1, 2023 consistent with Minn. Stat. § 216B.1615 and that various components and information be included in its filing.[7]
October 31, 2025	OTP files its 2025 TEP and IDP.[8]
November 13, 2025	The Commission issues its Notice of Comment Period in the present docket denoting.[9]

Topic(s) open for comment:

<u>2025 Otter Tail Power Integrated Distribution System Plan</u>

1. Should the Commission accept or reject Otter Tail Power's IDP?
2. Did Otter Tail Power adequately address the Commission's IDP filing requirements and

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[5] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure; In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan; In the Matter of Minnesota Power's 2021 Integrated Distribution System Plan; In the Matter of Distribution System Planning for Otter Tail Power Company, Order,* December 8, 2022, Docket Nos. E-99/CI-17-879, E-002/M-21-694, E-015/M-21-390, E-017/M-21-612 (eDockets) 202212-191192-01.

[6] Minn. Stat. § 216B.1615 (2023).

[7] *In the Matter of Otter Tail Power Company's 2023 Integrated Distribution Plan*, *Order Accepting 2023 Integrated Distribution Plan and Transportation Electrification Plan, and Modifying Reporting Requirements*, September 16, 2024, Docket No. E017/M-23-380, (eDockets) 20249-210225-01 (hereinafter "2023 IDP Order").

[8] *In the Matter of Otter Tail Power Company's 2025 Integrated Distribution Plan*, Otter Tail Power Company, October 31, 2025, Docket No. E017/M-25-141, (eDockets) 202511-224606-02 (hereinafter "2025 IDP").

[9] Notice.

prior Orders, as outlined in Attachment A to this notice?

3. Feedback, comments, and recommendations on the following areas of Otter Tail Power's IDP:
    a. Forecasted distribution budget
    b. Distributed Energy Resource (DER) scenarios and forecasts
    c. Planned grid modernization initiatives
    d. Non-wires alternatives analysis and potential pilot project
4. Other areas of Otter Tail Power's IDP not listed above, along with any other issues or concerns related to this matter.

2025 TEP

5. Should the Commission approve, modify, or reject Otter Tail Power's TEP?
6. Did Otter Tail Power adequately address the Commission's TEP filing requirements and prior Orders, as outlined in Attachment A to this notice?
7. Are there gaps in Otter Tail Power's transportation electrification programs the Commission should address to ensure equitable customer outcomes?
8. Are there other issues or concerns related to this matter?

III. DEPARTMENT ANALYSIS

These initial comments address OTP's IDP and TEP and the Commission's Notice Topics 1 through 8. Recommendations are offered in the corresponding sections and are summarized at the conclusion of this filing.

For reasons of organization and clarity, these comments do not follow the sequence of topics in the Notice.

A. IDP COMPLIANCE WITH FILING REQUIREMENTS AND RECOMMENDATIONS CONCERNING ACCEPTANCE

The Department responds to the following notice topics:

> *Notice Topic 1: Should the Commission Accept or Reject Minnesota Power's IDP?*
>
> *Notice Topic 2: Did Otter Tail Power Adequately Address the Commission's IDP Filing Requirements and Prior Orders, as Outlined in Attachment A to This Notice? Is Additional Information Necessary for Improved Clarity?*

The Department recommends the Commission accept OTP's 2025 IDP with additional recommendations. As part of the Department's review of OTP's October 31, 2025 filing, the Department verified that OTP's filing included the basic documentation required by the applicable Commission orders, rules, and statutes. While the Department's review process raised additional questions and concerns about the current filing, the attached compliance chart was created for the purpose of documenting OTP's compliance with the basic filing requirements established by the Commission for the current IDP docket.

B. FORECASTED DISTRIBUTION BUDGET

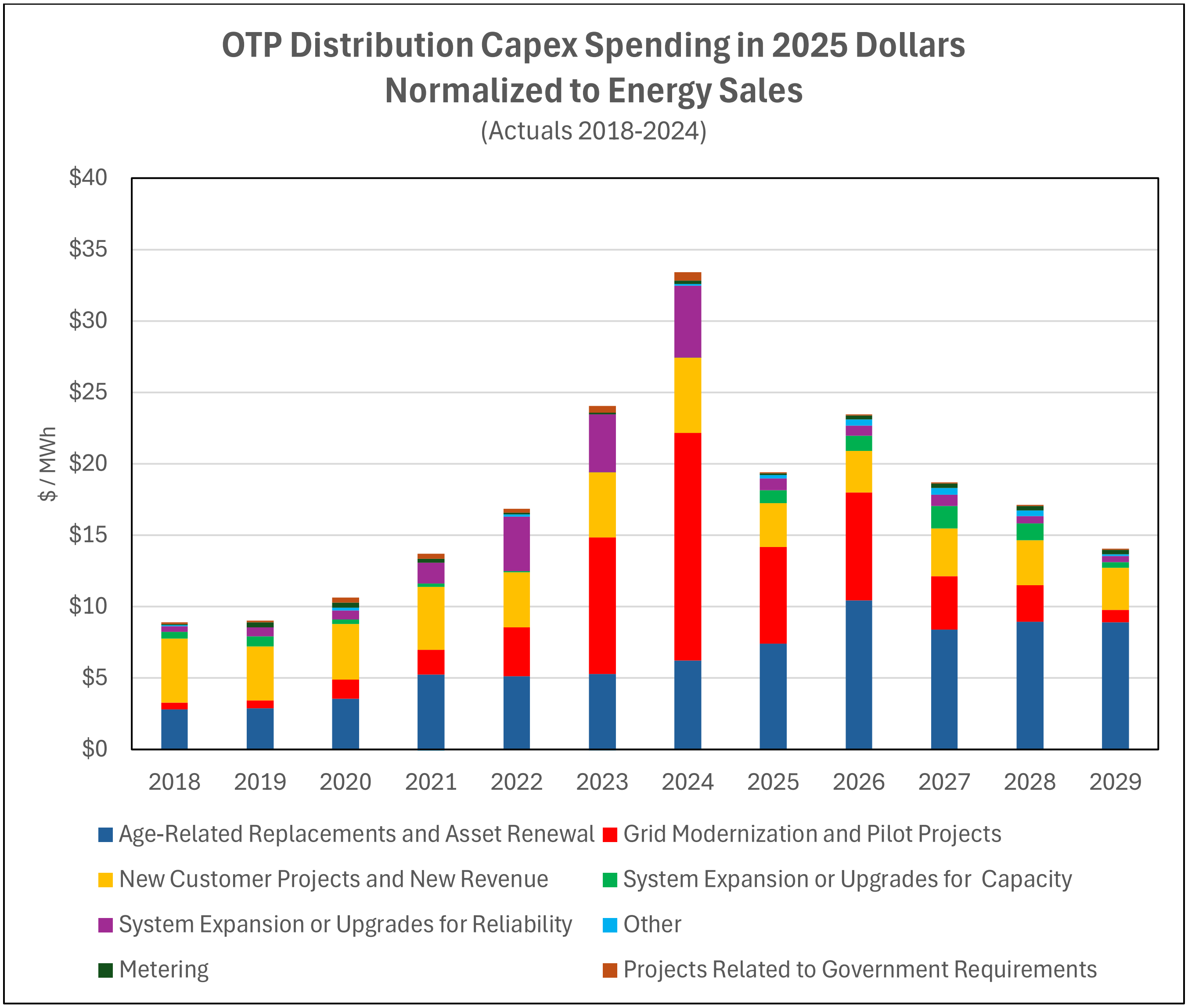
The Department responds to the following notice topic:

> *Notice Topic 3.C: Feedback, Comments, and Recommendations on the Forecasted Distribution Budget.*

B.1. Budget Summary

To support its strategic planning process, OTP has prepared a five-year financial forecast for the years 2025 through 2029 using the Capital Expenditure (capex) budget categories used by other utilities in their IDPs. The Department factored inflation and energy sales estimates into its calculations, to facilitate comparisons between the OTP budgets for the years 2018 through 2029 and potential comparisons with that of other Minnesota electric utilities. Figure 1 shows OTP's distribution spending among capex budget categories, in 2025 dollars, normalized to energy sales and covering the years 2018 to 2029. OTP's distribution spending for the years 2018 through 2024 are based on actual numbers and the data for the years 2025 through 2030 are based on forecasted numbers. While OTP's budget is forecasted to moderate from its 2024 high-point, the Department notes that its planned spending in 2029 is still 57 percent higher than its 2018 and 2019 average spending.

Figure 1: Summary of OTP's Distribution Capex Budget Controlled for Inflation and Energy Sales



Source: 2023 IDP,[10] 2025 IDP,[11] IR 6, IR 37.[12]

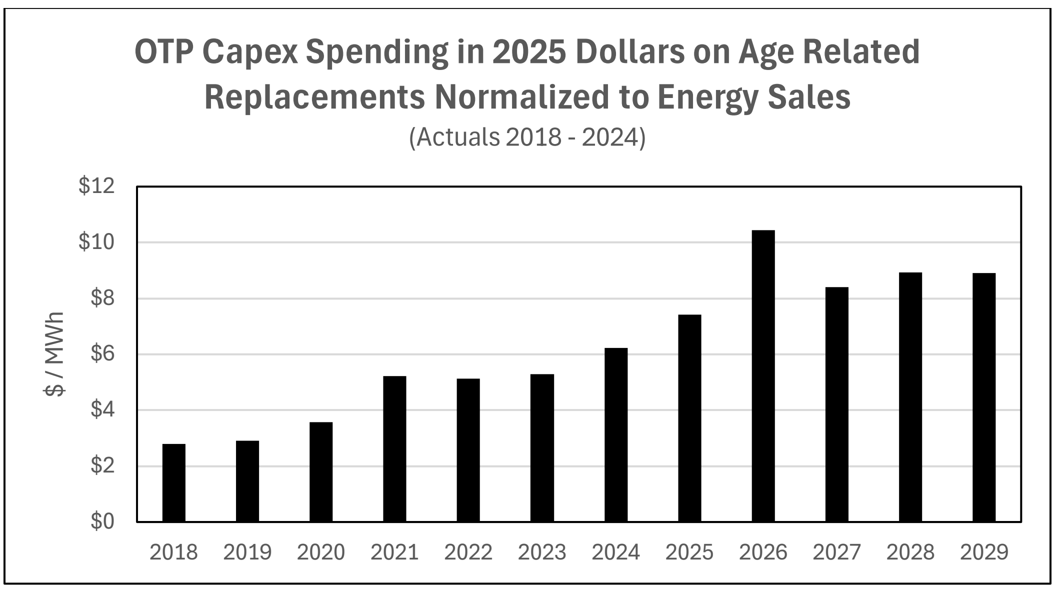
In Figure 1, the greatest relative spending increases occur in the following spending categories: Age Related Replacements and Asset Renewal; Grid Modernization and Pilot Projects; and System Expansion or Upgrades for Reliability and Power Quality.

[10] *In the Matter of Otter Tail Power Company's 2023 Integrated Distribution Plan,* Otter Tail Power Company, November 1, 2023, Docket No. E017/M-23-380, (eDockets) 202311-200138-02 at 38 (hereinafter "2023 IDP").
[11] 2025 IDP — at 34-35.
[12] The Department assumes 2% annual inflation after 2025, per Federal Reserve targets. Historical inflation based on June with data from https://www.bls.gov/data/inflation_calculator.htm

OTP states that spending on Age Related Replacements and Asset Renewal Projects "is used for planned or proactive work to replace aged and failing infrastructure field crews, engineers or other stakeholders have identified. This work is evaluated by engineering staff to assess risk and priority. […] As shown by the numbers in the tables below, this category makes up the largest portion of the distribution budget."[13]

Figure 2 shows OTP's Age-Related Replacements and Asset Renewal projects spending, in 2025 dollars, normalized to energy sales and covering the years 2018 to 2029. Spending on Age-Related Replacements and Asset Renewal projects, starts to slowly rise over the years 2018 through 2023, increases significantly during the year 2026, then is forecasted to moderately decrease during the years 2027 through 2029. OTP's forecasted Age-Related Replacements and Asset Renewal Budget makes up 47.8 percent of OTP's forecasted capex budget.

Figure 2: Summary of OTP's Age-Related Replacements and Asset Renewal Budget Adjusted for Inflation and Energy Sales



Source: 2023 IDP,[14] 2025 IDP,[15] IR 6, IR 37.[16]

OTP defines Grid Modernization and Pilot Projects according to the Commission's definition for this spending category:

> [A] modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy

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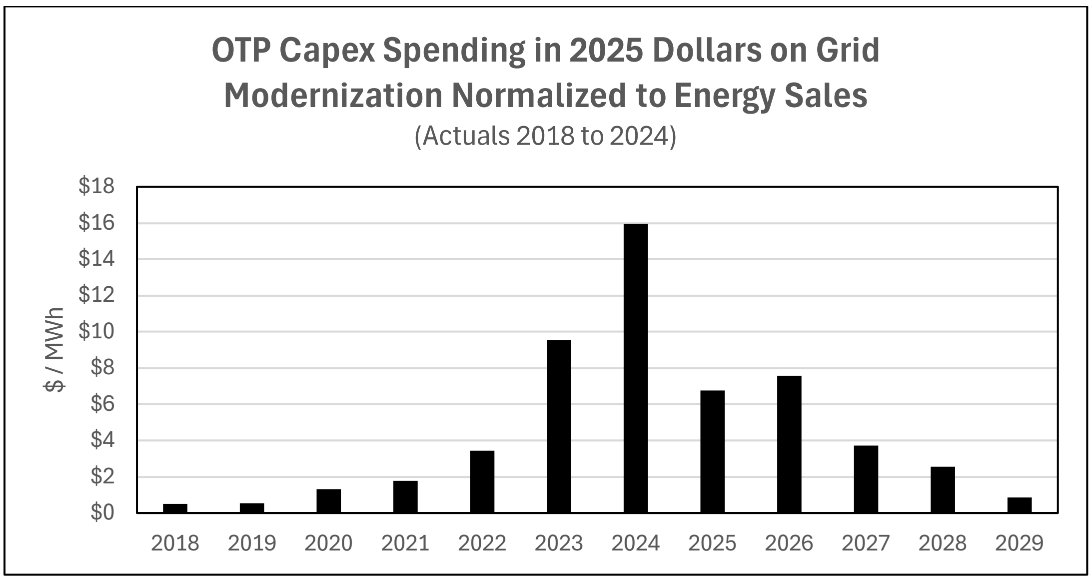
[13] 2025 IDP— at 32.
[14] 2023 IDP— at 38.
[15] 2025 IDP — at 34-35.
[16] The Department assumes 2% annual inflation after 2025, per Federal Reserve targets. Historical inflation based on June with data from https://www.bls.gov/data/inflation_calculator.htm

> goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network.[17]

OTP notes that, "[w]ith this definition, different projects could span the other definitions listed above and be considered as multi-value projects."[18] Figure 3 shows that spending on Grid Modernization and Pilot Projects stayed fairly moderate from 2018 through 2022, jumped during 2023 and 2024, then drops significantly from 2025 through 2029. Despite this decrease, Grid Modernization spending is anticipated to total $40.4 million between 2025 and 2029, which makes up 22.8 percent of OTP's forecasted capex budget.

Figure 3: Summary of OTP's Grid Modernization Budget Adjusted for Inflation and Energy Sales



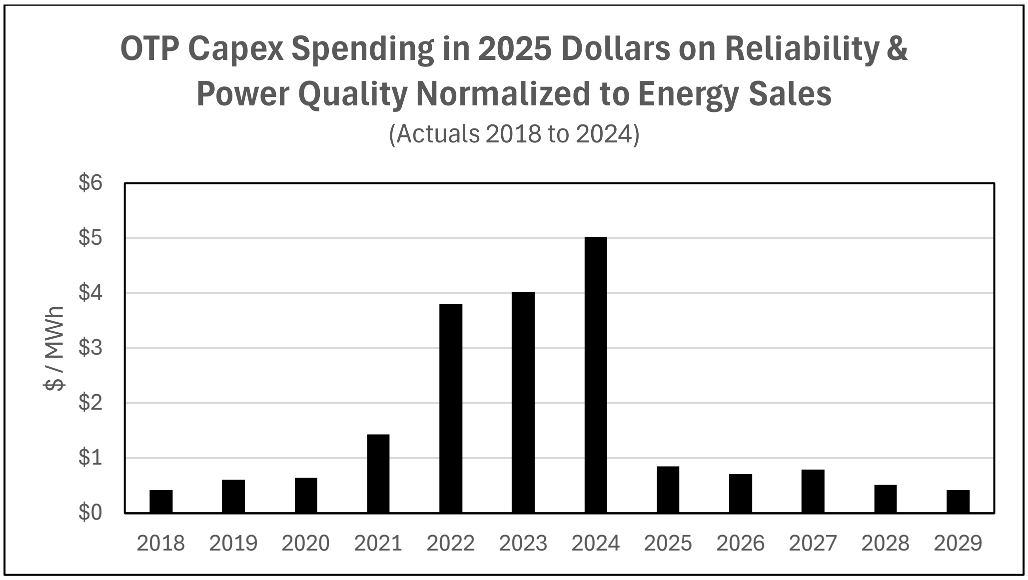
Source: 2023 IDP,[19] 2025 IDP,[20] IR 6, IR 37.[21]

OTP states that System Expansion or Upgrades for Reliability and Power Quality "includes projects that were generated primarily from reliability and power quality concerns and can include overhead (OH) to underground (UG) conversion projects as well as adding alternate feeds to the distribution system. In addition, this category also includes capital projects that were generated due to storms."[22] Figure 4

[17] *Id*., at 33.
[18] *Ibid*.
[19] 2023 IDP— at 38.
[20] 2025 IDP — at 34-35.
[21] The Department assumes 2% annual inflation after 2025, per Federal Reserve targets. Historical inflation based on June with data from https://www.bls.gov/data/inflation_calculator.htm
[22] *Id*., at 32.

shows that spending on System Expansion or Upgrades for Reliability and Power Quality stays relatively moderate during 2018 through 2021, increases significantly from 2022 through 2024, then is forecasted to decrease significantly from 2025 to 2029. OTP's forecasted System Expansion or Upgrades for Reliability and Power Quality Budget makes up 3.5 percent of OTP's forecasted capex budget.

Figure 4: Summary of OTP's System Expansion or Upgrades for Reliability and Power Quality Budget Adjusted for Inflation and Energy Sales



Source: 2023 IDP,[23] 2025 IDP,[24] IR 6, IR 37.[25]

B.2. Spending VS Rates

OTP states that the majority of its planned expenditures will be covered by existing rates:

> Although Otter Tail Power has not completed a cost-of-service study for the forecasted spend within the IDP, the following can be noted. Historically, Otter Tail Power's routine budget makes up approximately 78-80% of the spend within the 5-year forecast. These spends are supported by existing rates and do not drive a need for additional rate request. There are only a few programs within the 5-year forecast that do drive a need for additional recovery. Those programs and amounts are included below in Table 12.[26]

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[23] 2023 IDP— at 38.
[24] 2025 IDP — at 34-35.
[25] The Department assumes 2% annual inflation after 2025, per Federal Reserve targets. Historical inflation based on June with data from https://www.bls.gov/data/inflation_calculator.htm
[26] *Id*., at 36.

The Department presents the aforementioned Table 1 below:

Table 1: Summary of OTP's Planned Expenditures Not Covered by Existing Rates (2025-2029)[27]

PROGRAM NAME	AMOUNT (COMPANY TOTAL)	RECOVERY	IDP SPEND CATEGORY
AMI	$6.84M	EUIC Docket No. E017/M-21-382	Grid Modernization
Advanced Load Management	$18.33M	EUIC Docket No. E017/M-21-382	Grid Modernization
Wildfire Mitigation Program (WMP)	$33.92M	Future Rate Request	Grid Modernization & Age/Asset Renewal
Appleton – Benson Distribution Upgrades	$7.15M	Transmission Rider	Capacity

First, the Department notes that the $66.24 million outlined above is equivalent to 37.3 percent of OTP's 2025 – 2029 budget. If the spending outlined in Table 1 is planned entirely in the 2025 – 2029 period, then relative to OTP's 2025 – 2029 capex budget without the Table 1 expenditures, OTP's spending plan is equivalent to 59.5 percent of OTP's 2025 – 2029 capex budget. This spending plan therefore has a significant potential to increase OTP's rate base and will put pressure on OTP's existing rates. The Wildfire Mitigation Plan (WMP) alone is responsible for a little over half of the new spending.

Second, the Department presents its argument for why an analysis of spending is important, which was filed in the Department's Initial Comments on Xcel's 2025 IDP:

> Utility spending and rates are two different, but related concepts. Utility spending is a straightforward concept, which totals all the money the utility plans to spend during a specified period of time. Rates are the costs that are passed onto ratepayers to recover costs from spending. Increases in utility spending may not be commensurate with rate increases, because rates can be designed to capture the ebb and flow of spending, providing a more even distribution of spending. Additionally, the capital spending budgets presented by Xcel are only capitalized costs. Actual cost recovery, or resulting revenue requirements, could be two to three times higher over a potentially 50-year depreciation window, after adding the weighted cost of capital, taxes, and other related expenses. While spending does not equal rates directly, an analysis of utility spending can be helpful in analyzing the impact on utility rates.
>
> Regardless of rate impacts, every additional dollar that Xcel spends or saves puts upward or downward pressure on rates. Every year that a utility

[27] *Ibid*.

> asset remains on Xcel's system (because it is not retired) is another year that Xcel does not have to spend money to replace the asset, regardless of whether the asset is depreciated or not.[28]

To summarize this argument, if OTP can reduce its current distribution spending, then it will put downward pressure on the need to increase rates. Therefore, simply stating that "[t]hese spends are supported by existing rates and do not drive a need for additional rate request," misses the larger context in which OTP's rate-supported spending is entirely related to additional rate requests.

C. CAPACITY

The Department responds to the following notice topic:

> *Notice Topic 6: Other Areas of Otter Tail Power's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

C.1. Substation Utilization

The Department seeks to understand how Minnesota utilities plan their systems for capacity. The first step in this process is to measure substation transformer capacity to determine substation utilization. This utilization data provides a barometer for right sizing equipment, and can indicate if OTP's system is stressed due to under sizing, appropriately sized, or oversized.

The Department attempted to make a substation capacity utilization graph, similar to those presented for other utilities, however OTP was unable to provide the Department with the necessary information. The Department requested non-redundant substation capacity and 3-year highest peak load data in IR 8, but OTP only provided capacity for its substation transformers. OTP responds:

> OTP does not currently have the capability to provide accurate 3-year highest peak load observed at MN substations due to our AMI substation meter upgrades, data integration development and data historian status.[29]

The Department believes this response may have been misunderstood. The Department requests peak load data from OTP's substation transformers that are equipped with SCADA data logging capabilities, and not advanced metering infrastructure (AMI). The Department seeks to create figures similar to Figures 6 and 7 in the Department's Initial Comments on Dakota Electric's 2025 IDP.[30] Figure 6 shows utilization based on normal substation transformer capacity ratings and Figure 7 shows utilization based on emergency capacity ratings. Similar to how the Department analyzes other utility's capacity

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[28] Department Initial Comments on Xcel's 2025 IDP— at 26.
[29] IR 8. Note that Attachment 1 is not included in these comments, but can be provided upon request.
[30] *In the Matter of Dakota Electric Association's 2025 Integrated Distribution Plan*, Department, Comments, March 24, 2026, Docket No. E111/M-25-139, (eDockets) 20263-229585-01, at 9-10.

utilization, the Department seeks to understand A) how utilized OTP's substation transformers are and whether they are appropriately sized, and B) how OTP evaluates the need for substation transformer capacity upgrades when capacity ratings are exceeded. Given this data omission, the Department requests OTP to present the data that the Department would have presented if the data was provided in IR 8. The Department seeks to provide the same analysis in reply comments as it intends to provide for the other utilities.

The Department requests OTP present in reply comments, a summary histogram that plots the number of substation transformers in bins of substation transformer utilization (peak load / rated capacity) sized at 10% bin widths, from 0% to 100%, with an overflow bin of ≥ 100%. OTP should provide a second histogram of substation transformer utilization compared to emergency ratings, if this data is readily accessible. These histograms should exclude substations with either 0 measured load or no data logging capabilities.

The Department requests OTP explain in reply comments how the Company views capacity overload risks at its substations and the need for capacity mitigations with historic or existing substation transformer overloads. As applicable, OTP should discuss why the Company has no plans to mitigate substation transformer capacity overloads at any substation transformers that have not been identified for upgrades.

C.2. Capacity Planning Standards

OTP makes capacity upgrade decisions as part of its targeted distribution planning study process. OTP describes how it determines the need for a targeted distribution planning study:

> a. Historically, OTP would determine the need for a targeted distribution planning study in one of two ways: When notified of a planned expansion or load addition, the Area Engineer would inform OTP's Distribution Studies Engineer to conduct a targeted planning study to identify any system deficiencies related to the new load.
>
> b. The Distribution Studies Engineer reviews our historical studies to identify towns or systems not studied in over three years, then conducts targeted assessments to gauge current system health. This may also be prompted by issues noted in OTP's internal Feeder Data Spreadsheet, discussed further in response to question #2.[31]

OTP also discusses how it plans to proactively use AMI data to proactively identify system risks and incorporate this process into its existing planning process:

[31] IR 33.

> Following the completion of our Advanced Metering Infrastructure (AMI) meter rollout, OTP plans to utilize the interruption, reliability, and demand data from our AMI fleet to identify distribution systems that need a planning study in a more proactive manner.
>
> Feeder Data Spreadsheet: OTP tracks substation and feeder loading percentages and power factors annually. This helps identify areas with poor power factors or load/DER growth nearing capacity, which then triggers targeted distribution planning studies.
>
> Annual Load-Flow Analyses: Each summer, the Delivery Planning department conducts general load-flow analyses. These analyses, along with input from local Area Engineers and trends from the Feeder Data Spreadsheet, help pinpoint areas needing more in-depth study.
>
> Advanced Metering Infrastructure (AMI): Once the AMI rollout is complete, OTP will use detailed customer-level telemetry from advanced meters to enhance future planning studies (e.g., 5-10 year forecasts). This will allow more precise, proactive identification of system issues, supporting better decision-making and improving reliability and customer satisfaction.[32]

The Department notes that OTP's Feeder Data Spreadsheet appears to contain the feeder loading data that the Department requested in IR 8.

The Department requests OTP present in reply comments, a feeder utilization histogram that is comparable to the Department's requested substation transformer utilization histogram using OTP's Feeder Data Spreadsheet.

OTP states that it will mitigate most N-0 capacity risks at 90 percent capacity:

> Otter Tail Power begins planning for system upgrades once a facility has been identified as exceeding 90% of its' thermal rating near peak demand through telemetry data or through planning studies. However, some equipment, such as transformers for example, can handle short-duration thermal overloads better than other facilities can. Therefore, in certain circumstances, OTP does allow transformers to exceed their thermal rating, as long as it's for short durations, before requiring a transformer upgrade. This can be necessary given the long-lead times and difficulties in procuring new transformers. It should be noted that with AMI data, the

[32] *Ibid.*

> granularity in which this analysis can be completed will be much greater than historical. OTP is anxious to start using the demand information from the newly installed AMI system.[33]

OTP also mitigates all of its N-1 (contingency) capacity risks, and does not incorporate the probability of these events into its decision process:

> Otter Tail Power strives to provide redundancy for our customers to increase both customer satisfaction and system reliability. Therefore, in cases where redundancy on the distribution system is feasible or exists already, OTP does include N-1 contingency events in our distribution planning standards. The probability of the N-1 events occurring has not been historically considered, which is consistent with transmission planning standards as well.[34]

As OTP states in its IDP, the Company has 422 communities with an average population of 400.[35] Due to the rural nature of OTP's service area, the Department expects that the majority of OTP's system does not have N-1 redundancy, because it would be too expensive to install transfer capabilities over miles and miles of distribution lines. Therefore, OTP's 90 percent capacity planning standard should be suitable for the majority of OTP's system, which only operates under N-0 conditions. However, where OTP mitigates N-1 risks, if adjacent feeders or laterals are at or near capacity, OTP may mitigate these capacity risks below 90 percent loading if transfer feeders at also at 90 percent loading.

The Department analyses one additional capacity planning standard used by OTP. In its IDP, OTP states:

> It should be noted that design standards create system capacity "step changes." For example, underground feeder design standards are rated at either 200 or 600 ampacity, or substation transformer sizing which is standardized to future purchases of 1 MVA or 2.5 MVA. This helps maintain efficient installation, and stock inventory of replacement asset materials. In doing so, building of the distribution system can appear "overbuilt" in terms of capacity. However, the system was not overbuilt at all but rather efficiently planned, designed and constructed to handle future growth.[36]

As the Department assumed, if a project needs 10 percent more capacity than the 200 amp standard, then OTP would build to the 600 standard, which OTP confirms in its response to the Department Information Request 22. OTP provides an analysis of its existing 1/0 cable standard, rated at 218 amps, a non-OTP 2/0 hypothetical standard rated at 248 amps, and OTP's next standard level for 4/0 cable

[33] IR 24.
[34] IR 26.
[35] 2025 IDP —at 10.
[36] *Id*., at 13-14.

rated at 324 amps. OTP's analysis shows values relative to the 1/0 cable, and is shown in the below figure.

Figure 5: OTP Analysis of the Marginal Cost of a 2/0 VS 4/0 Cable Upgrade Relative to 1/0 Cost

Industry Standard MV Cable Sizes	Ampacity	DeadBreak Connections Ampacity	Relative Ampacity	Purchase Price $/ft (Relative)	Install Cost low (1 Ph Primary - Lateral) $/FT	Install Cost low (3 Ph Primary - Feeder) $/FT	Install Cost High (Boring 1 Ph Primary Lateral) $/FT	Install Cost High (Boring 3 Ph Primary Feeder) $/FT	Relative Installed Total $/FT Low Lateral	Relative Installed Total $/FT High Lateral	Relative Installed Total $/FT Low Feeder	Relative Installed Total $/FT High Feeder
2 sol	168	200	0.77	0.82	0.75	1	3	5	0.90	2.18	N/A	N/A
2 str	168	200	0.77	0.84	0.75	1	3	5	0.91	2.19	N/A	N/A
1 sol	193	200	0.89	0.9	0.75	1	3	5	0.94	2.23	N/A	N/A
1 str	193	200	0.89	0.93	0.75	1	3	5	0.96	2.25	N/A	N/A
1/0 sol	218	200	1.00	1	0.75	1	3	5	1.00	2.29	2.29	4.57
1/0 str	218	200	1.00	1.03	0.75	1	3	5	1.02	2.30	2.34	4.62
2/0 str	248	200	1.14	1.18	0.75	1	3	5	1.10	2.39	2.59	4.88
3/0 str	284	200	1.30	1.23	0.75	1	3	5	1.13	2.42	2.68	4.97
4/0 str	324	600	1.49	1.33	0.75	1	3	5	1.19	2.47	2.85	5.14
250 str	360	600	1.65	1.36	0.75	1	3	5	1.21	2.49	2.90	5.19
350 str	389	600	1.78	1.4	0.75	1	3	5	1.23	2.51	2.97	5.26
500 str	468	600	2.15	1.46	N/A	1.2	N/A	5	N/A	N/A	3.19	5.36
750 str	569	600	2.61	1.63	N/A	1.2	N/A	5	N/A	N/A	3.48	5.65
1000 str	642	600	2.94	1.67	N/A	1.2	N/A	5	N/A	N/A	3.55	5.72
1250 str	688	600	3.16	1.78	N/A	1.2	N/A	5	N/A	N/A	3.74	5.91
1500 str	726	600	3.33	1.82	N/A	1.2	N/A	5	N/A	N/A	3.81	5.98

*OTP Standard MV UG Cable Sizes
*Ampacity limited by Connections
*Connection Ampacity not fully utilized
*Base unit for caculation of costs

Regarding its analysis, OTP states:

> In summary, if 1/0 sol cable capacity is exceeded by 10%, necessitating an increase step to next standard cable size of 4/0, installed cost increases to range of 1.19-2.47 for laterals and 2.85-5.14 for feeders.
>
> Similarly, if 1/0 sol capacity is exceeded by 10% and an additional standard of 2/0 was added, total installed cost increase to a range of 1.10-2.39 for laterals and 2.59-4.88 for feeders.
>
> By having a step change from 1/0 to 4/0 instead of 1/0 to 2/0 (non-OTP standard), corresponds to a 3-8% installed cost adder for laterals and a 5-10% cost adder for feeders. However, ampacity changes from a 200 amp limitation to 600 amp limitation. The other benefits of maintaining standards are discussed in the IDP in Section 4.[37]

OTP's analysis is very helpful to justify OTP's step from 1/0 to 4/0 cable, as the marginal cost increase is 10 percent or less compared to a 2/0 cable. The Department notes that the 2/0 cable is not labeled in

[37] *Ibid*.

red as "Ampacity Limited by Connections," when the 1000 str, 1250 str and 1500 str cables are all labeled as such with higher cable ampacity ratings than the DeadBreak rating, and therefore the 4/0 cable would likely need a higher ampacity DeadBreak to utilize the full marginal capacity benefit. At this time, the Department finds OTP's 1/0 to 4/0 cable standard to be reasonable. The marginal cost savings of a 2/0 standard should be weighed against inventory and replacement costs to stock additional equipment. The Department finds this type of analysis to be highly valuable, and seeks additional analysis of this manner in future IDP filings.

While OTP makes a sufficient case for its 1/0 to 4/0 cable size step, OTP does not provide justification for its 1 MVA to 2.5 MVA substation transformer step. OTP could alternatively choose a 1.5 MVA or 2.0 MVA transformer as the next step, which would represent a 50 and 100 percent relative increase in capacity as opposed to a 150 percent increase in capacity. The Department expects OTP's transformer costs to scale with size, and therefore this standard may add significant cost to OTP. As stated earlier in this section, OTP is mostly experiencing stagnant growth, and therefore such a large increase in capacity will likely not be utilized.

The Department requests OTP present in reply comments a cost effectiveness analysis of a 1.5 MVA and 2.0 MVA substation transformer sizing standard compared to its 2.5 MVA standard.

In summary, OTP performs infrequent targeted distribution studies that identify capacity and other mitigation needs on OTP's distribution system. OTP mitigates its N-0 capacity risks at 90 percent loading, and mitigates its N-1 risks without consideration of the probability of N-1 contingencies when N-1 mitigations are feasible. OTP's forecast accuracy in recent years has been within an acceptable range. OTP's 200- and 600-amp line capacity standards are reasonable, and the Department will draw a final conclusion for OTP's 1 MVA to 2.5 MVA substation transformer capacity standard in the Department's reply comments.

D. RELIABILITY

The Department responds to the following notice topic:

> *Notice Topic 6: Other Areas of Otter Tail Power's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

The Department's review of OTP's 2025 IDP reliability-related filing suggests that OTP has a general need for continued reliability and resiliency investment but has not provided analytical justification for increased spending on major reliability programs and whether the programs are targeted, prudent, and cost-effective for ratepayers. OTP's 2025 IDP and 2024 SRSQ[38] point to concentrated reliability

[38] *In the Matter of Otter Tail Power Company 2024 Annual Safety, Reliability and Service Quality Report and Proposed SAIFI, SAIDI, and CAIDI Reliability Standards for 2025*, Otter Tail Power Company, Report, April 1, 2025, Docket No. E017/M-25-30, (eDockets) 20254-217089-01 (hereinafter "2024 SRSQ")

issues on specific feeders and a mix of potentially useful tools, such as undergrounding, asset replacement, and operational improvements. The Department finds the justification for these investments to be lacking in quantified reliability outcomes or transparent comparisons with lower-cost alternatives. The Department's recommendations focus on strengthening the information, justification, and prioritization systems that underlie OTP's reliability portfolio. The Department believes that this strategy will more effectively balance reliability gains with customer affordability and risk.

D.1. Reliability Performance and Outage Drivers

OTP's 2024 normalized Minnesota reliability performance, from the 2024 SRSQ, is shown in Table 2. The Department's 2024 SRSQ initial comments further identify persistent worst-performing feeders, which includes the Fergus Falls North Feeder (Ottertail City Substation) as a worst performer for the "last six years" and the Morris North Feeder (Wheaton Substation) as a worst performer for the "last two years."[39] The filing also documents a long 907-minute interruption for 39 customers downstream of the Morris South feeder due to failed underground cable on November 29, 2024.[40]

Table 2: OTP's Normalized Reliability Performance vs. 2023 IEEE Benchmark[41]

Metric	2024 OTP Performance	2023 IEEE Benchmark
SAIDI	141.55	121.00
SAIFI	1.16	1.00
CAIDI	122.22	139

Table 3 shows the causes of outages in OTP's distribution system for 2023 and 2024. For both years, the top three causes of outages were: material or equipment failure, squirrel, and maintenance, which account for almost 50 percent of all outages in both years.

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[39] *Otter Tail Power Company's 2024 Annual Safety, Reliability and Service Quality Report and Proposed SAIFI, SAIDI, and CAIDI Reliability Standards for 2025,* Department, Comments, July 11, 2025, Docket No. E017/M-25-30, (eDockets) 20257-220872-01 (hereinafter "Department's 2024 SRSQ Initial Comments").
[40] *Id.,* Table 5 at 17.
[41] *Id.,* Table 3 at 11.

Table 3: Summary of OTP Outages by Cause and Frequency in 2023 and 2024.[42]

2023 – MN Distribution Outages by Cause

Cause	Outage Count
Material or equipment failure	303
Squirrel	213
Maintenance	203
Weather	201
Tree on the line	156
Cause unknown	143
Public	120
Animal caused, not squirrel	51
Equipment fault or operation	24
Fire	10
Downstream customer issue	10
2023 Total	1434

2024 – MN Distribution Outages by Cause

Cause	Outage Count
Maintenance	220
Material or equipment failure	217
Squirrel	177
Tree on the line	167
Cause unknown	156
Weather	129
Public	108
Animal caused, not squirrel	35
Fire	19
Downstream customer issue	14
Equipment fault or operation	10
2024 Total	1252

The Department recommends that OTP, in its reply comments, provide a short narrative linking each major reliability-driven program in Appendix B, by MN IDP Category, to specific outage causes, reported in Table 3. The narrative should also quantify, where feasible, the share of each program's Minnesota spend that is directed at each primary cause category.

D.2. Reliability-Driven Spending

Table 4: OTP 2025 IDP Table 10- Historical Distribution Spend for Reliability and Power Quality Upgrades

2020	2021	2022	2023	2024
$886,530	$2,093,766	$6,207,152	$6,672,603	$8,670,094

Table 5: Forecasted 5-year Distribution Spend for Minnesota (with WMP) for System Expansion or Upgrades for Reliability and PQ[43]

2025	2026	2027	2028	2029
$1,557,548	$1,350,924	$1,530,000	$1,017,500	$845,000

Table 4 shows OTP's historical distribution spend for reliability and power quality upgrades from 2020-2024. Table 5 shows the forecasted distribution spend for system expansion upgrades for reliability and power quality for 2025-2029. The 2025-2029 forecasted distribution spend average is 74 percent lower than the historical spending average for reliability and power quality upgrades.

[42] IR 5.
[43] IR 11.

The Department requests that OTP, in reply comments, explain the reasoning behind the significant reduction in the forecasted budget for reliability and power quality upgrades from 2025-2029.

The Department requests that OTP, in reply comments, report its reliability metrics outcomes, categorized with workstation and substation, from the reliability and power quality investments made from 2020-2024. These metrics should include actual SAIDI, SAIFI, CAIDI, and customer minutes of outage (CMO), where applicable.

The Department recommends the Commission require OTP, in its next IDP, to develop clear reporting metrics for its reliability projects (e.g., miles converted, segments addressed) and provide a clear methodology for selecting segments in its distribution system for reliability and power quality upgrades.

D.3. Strategic Undergrounding

OTP's 2025 IDP identifies several reliability and resiliency needs and presents a portfolio of age-related renewal and hardening programs, including a Strategic Overhead-to-Undergrounding (OH-to-UG) Line Conversion Program and a dedicated Undergrounding (UG) Asset Replacement budget category within its System Infrastructure Renewal Initiative (SIRI) framework.[44] In the IDP, the Company explains that its SIRI OH-to-UG program "is intended to improve reliability, resiliency, and system performance by proactively replacing poor performing and/or hard to access overhead line sections, with new UG cable infrastructure," particularly in "mature neighborhoods prone to frequent outages" and areas with "little or no access for restoration without damaging customer property."[45]

To prioritize OH-to-UG spending, OTP states that Area Engineers "utilize the following criteria: safety concerns; number of customers impacted; historical outage history; limited access for outage restoration; limited access for routine vegetation management and maintenance; [and] feasibility to remove OH line from back lot lines, and install new UG infrastructure on front lot lines, or along roads."[46]

The Department requests that OTP, in reply comments, explain the reasoning behind classifying OH-to-UG conversion projects to two MN IDP Categories (PQ & Reliability Upgrades and Age Related/Asset Renewal) in Appendix B.

D.4. Value of Reliability

The Department is concerned that the lack of quantitative analysis in OTP's strategic OH-to-UG projects could lack quantitative analysis; the Department is correspondingly concerned that the lack of

[44] 2025 IDP—at 44-47.
[45] *Id.,* at 46.
[46] *Ibid.*

quantitative analysis may lead to subjective decision-making and investments. This process stands in contrast to that of Xcel Energy, which in its 2025 IDP[47] presented a scenario analysis in which 49 selected feeders were estimated to avoid 10.5 million customer minutes out (CMO) annually with an indicative benefit-cost ration (BCR) of 1.5, based on ICE customer interruption cost values and an assumed $1.5 million per mile undergrounding cost.[48] OTP's 2025 IDP cites qualitative goals and prioritization criteria for its SIRI OH-to-UG and UG Asset Replacement programs but does not provide feeder-level projections of avoided outage minutes, SAIDI/SAIFI improvement projects, or project-specific BCRs for its Minnesota undergrounding-related spending. In response to Department IR 30, which asked OTP if they use a monetized value of customer minutes of outages (CMO) to compare costs, OTP states:

> Otter Tail has not yet measured the value of reliability. When selecting projects for upcoming budgets, a review of historical reliability data is a major factor. Circuits or parts of the system that have performed poorly in terms of reliability are given higher priority for improvements. Section 9.F of the IDP report covers additional project planning criteria besides reliability.[49]

The Department recommends the Commission require OTP, in its next IDP, 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.

The 2025 IDP's Appendix B (Forecasted Spend Detail) shows annual budgets for Strategic OH-to-UG Conversions, Underground Primary Replace, and WMP-related OH-to-UG and inspection programs, but the Company does not tie these dollars to quantified Minnesota reliability benefits or to specific poor-performing feeders:

> OTP does not perform a standalone cost-benefit or predictive analysis specific to each overhead-to-underground (OH-to-UG) conversion project. However, OTP maintains and reviews historical feeder performance data for circuits where OH-to-UG projects have been completed. This historical data clearly demonstrates substantial improvements in reliability metrics following project completion, including significant reductions in outage frequency and duration. These post-project performance gains provide

[47] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, Xcel, Compliance Filing, October 31, 2025, Docket No. E002/M-25-142, (eDockets) 202510-224538-01, (hereinafter "Xcel's 2025 IDP")
[48] *Id.,* at 14-15.
[49] IR 30.

> strong empirical evidence that OH-to-UG conversions materially improve system reliability and customer service outcomes.[50]

While targeted undergrounding may be a reasonable tool that OTP deploys on at least some of its documented poor-performing feeders, it does not yet demonstrate that the scale and location of those expenditures are optimized for OTP's Minnesota ratepayers.

The Department requests that OTP, in reply comments, provide a short summary table for all Minnesota strategic OH-to-UG project planned or completed during 2025-2029. This table should specify which criteria (safety, customer impacted, outage history, restoration access, vegetation-management access, backlot vs. front-lot routing) were determinative in selecting that project. Additionally, OTP should identify any feeders that met several criteria but were not selected and explain the reasons for their exclusion.

D.5. Reliability Examples and Use of Mitigation Methods

In its 2024 SRSQ, OTP explains that its action plan emphasizes Outage Management System (OMS) deployment, GIS data improvements, vegetation management, and targeted upgrades on poor-performing feeders.[51] The Department's 2024 SRSQ initial comments note that it anticipates OTP's new OMS, implemented in December 2022, "will take several years of data reported from the OMS to begin to be able to assess trends in the Company's reliability metrics included in the Annual Report."[52]

The Department's 2024 SRSQ initial comments also note examples of OTP's mitigation approach for specific feeders:

- Fergus Falls: the Company reports that it completed a project in June 2024 "to replace existing overhead primary lines with underground cabling" and that, based on prior conversions, it "anticipates improved reliability for this feeder as well."[53]
- Morris: OTP's 2024 SRSQ identifies the feeder as a repeat worst performer and documents a 15-hour outage for 39 customers tied to a bad underground section on the Morris South feeder, which led to an OH-to-UG conversion project in November 2024.[54,55]

[50] IR 16.
[51] 2024 SRSQ – at 15-17.
[52] Department's 2024 SRSQ Initial Comments– at 14.
[53] *Id.*, at 17.
[54] *Id.*, at 18.
[55] 2024 SRSQ – at 36.

The Department requests that OTP, in reply comments, provide, for at least Fergus Falls and Morris, pre-project and post-project feeder-level SAIDI, SAIDI, and CAIDI values for at least the most recent 12-24 months.

D.6. Cost Information

To understand the relative economics of overhead and underground construction, the Department requested in IR 17, the generic cost information for new one-mile sections of overhead and underground feeders and taps. OTP's response is shown in Table 6, normalized costs relative to a one-mile single-phase overhead tap.

Table 6: OTP IR Table- Generic Estimates for a New Build Typical One Mile Section of Overhead (OH) and Underground (UG) feeders and tap lines. Costs have been normalized relative to 1 mile of single phase overhead tap construction.[56]

Type	Phase	Relative Cost/Mi
Overhead Tap	1	1.00
Overhead Feeder Low End	3	1.33
Overhead Feeder High End	3	1.50
Underground Tap	1	0.79
Underground Feeder Low End	3	1.69
Underground Feeder High End	3	4.60[57]

The Department notes that these generic estimates show a single-phase underground tap (0.79) as less expensive than a single-phase overhead tap (1.00), which is atypical relative to the general industry understanding that underground distribution is usually more expensive than comparable overhead construction on a per-mile basis.

The Department requests that OTP, in reply comments, explain why its normalized generic cost estimates show underground taps as less costly than overhead taps, including: 1) what specific cost components (labor, materials, easements, restoration) are included for each case; 2) whether different design assumptions (e.g., conductor size, trenching conditions, service configuration) apply to the tap cases; and 3) whether these values reflect Minnesota specific or system-wide averages.

D.7. Alternative Methods to Improve Reliability and Power Quality

Appendix B of OTP's 2025 IDP shows that its Minnesota distribution forecasts include sustained, multiyear spending on Strategic OH-to-UG Conversions, Underground Primary Replace, and WMP- related OH-to-UG, SCADA reclosers, inspection, and cutout replacement from 2025 through

[56] IR 17.
[57] High end range represents directional boring of very large underground cable which drives up costs.

2029.[58] Further, Appendix B shows a SIRI Porcelain Cut-Out Replacement Program and a Distribution Pole Replacement Program that also provide reliability and resiliency benefits, many of which are further accelerated on WMP "high-risk feeders."[59] While the exact Minnesota only totals for undergrounding and underground replacement are spread across several line items, the Department is concerned that OTP is committing to a material, long lived undergrounding portfolio without providing Minnesota- specific projections of avoided outage minutes, SAIDI/SAIFI reductions, or per project BCRs.

The Department's initial comments on Xcel's 2025 IDP highlight that overhead-to-underground conversions are capital- intensive. DOE benchmarking shows cost ranges from roughly $0.16–$0.48 million per rural mile up to several million dollars per urban mile, with cost- effectiveness dependent on "discount rates, under-grounding replacement cost, overhead T&D lifespan, value of lost load, reliability impact from undergrounding, and customers per line mile."[60] The Department also emphasized that "enhanced vegetation management, FLISR deployment, and backlot O&M expenses" must be formally quantified as alternatives to undergrounding.[61] In OTP's 2025 IDP, the WMP section notes that WMP-based programs "also provide tremendous reliability benefits in addition to reducing wildfire risk," including burying all steel and copper wire across moderate to very high WMP risk areas and replacing all porcelain cutouts on high-risk feeders over three years.[62] Yet, OTP's 2025 IDP does not distinguish between expenditures justified primarily by wildfire risk and those justified primarily by conventional reliability in Minnesota, nor does it quantify the Minnesota reliability benefits from these WMP OH-to-UG and asset health programs.

The Department concludes that OTP has not demonstrated that its Minnesota undergrounding and underground replacement budgets are optimized relative to lower-cost options such as enhanced vegetation management, sectionalizing, reclosers, animal guards, overhead rebuilds, and backlot O&M strategies. The Department also finds that OTP has not shown that WMP-related undergrounding is appropriately attributed between wildfire risk reduction and conventional reliability benefits.

The Department recommends that targeted undergrounding be evaluated alongside other reliability mitigation methods that can materially reduce outage minutes on targeted feeders.

[58] 2025 IDP – Appendix B.
[59] *Id.,* at 47.
[60] Department Initial Comments on Xcel's 2025 IDP – 81 at Table 8.
[61] *Id.,* at 82
[62] 2025 IDP – at 47.

E. AGE RELATED REPLACEMENTS AND ASSET RENEWAL

The Department responds to the following notice topic:

> *Notice Topic 6: Other Areas of Otter Tail Power's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

Age Related Replacements and Asset Renewal projects and their potential deferrals represent the highest risks for reliability. Outages at the substation or feeder level can affect hundreds to thousands of customers, and the Department does not seek to increase the frequency of these events. However, the possibility of large outage events does not mean that spending in the Age Related Replacements and Asset Renewal category should go unscrutinized, particularly given its magnitude in OTP's budget. No utility would replace a normally functioning transformer after only ten years, so there is a limit to when these projects are necessary. The Department seeks to test these limits to verify that OTP optimizes the balance between capital costs and reliability.

E.1. Budget Categories

Age Related Replacements and Asset Renewal are OTP's largest spending category in its forecasted 2025 to 2029 budget, at 47.8 percent of OTP's budget. Table 7 shows the Department's summary of OTP's spending projects over $500,000. The table represents $66.4 million out of OTP's planned $84.8 million in the Age Related Replacement spending category. Of this subtotal, $23.1 million is for OTP's Wildfire Mitigation Plan (WMP), which is discussed in the next section. After subtracting the cost of OTP's WMP, OTP's 2025 Dollar Age Related Replacements and Asset Renewal budget in 2025 – 2029 is $58.3 million and OTP's 2025 Dollar Age Related Replacements and Asset Renewal budget in 2020 – 2024 was $44.6 million, which is an increase of 30.7 percent. The Department expects that if the WMP is not funded, that some double digit fraction of OTP's WMP-related expenditures would be converted to normal Age Related Replacement and Asset Renewal spending, and therefore the 30.7 percent increase is anticipated to be conservative.

Table 7: Summary of OTP's Age-Related Replacements and Asset Renewal Budget Categories Over $500,000

Spending Category	**2025-2029 Cost**
Underground Replacement	$10,887,500
WMP Inspection	$9,630,000
WMP New Underground	$9,120,000
General Distribution Replacement	$8,875,000
Substation New/Rebuild	$7,400,000
Underground New	$5,810,000
Cut-Out Replacement	$4,750,000
WMP Cut Out Replacement	$3,850,000
Other	$2,720,000
Voltage Regulator	$1,575,000
Pole Replacement	$1,250,000
WMP Fuse Replacement	$542,700
Total	**$66,410,200**

Source: 2025 IDP – Appendix B

The Department's primary focus in OTP's Age Related Replacements budget regards the timing and need for asset replacement. In OTP's response to Department IR 29, OTP provides a summary of the depreciation service lives OTP uses for asset depreciation, which is shown in Table 8. Regarding Table 8, OTP states that "these are financial depreciation values and not necessarily what the expected life might be for an asset in the field."[63]

Table 8: Summary of Depreciation Service Life[64]

Asset Type	**Average Service Life**
Distribution Poles	364 Poles, Towers & Fixtures – 72 Years
Distribution Insulators	365 Overhead Conductor & Devices – 68 Years
Pad mount Transformers	368 Line Transformers – 45 Years
Pole mount Transformers	368 Line Transformers – 45 Years
Underground Cable	367 Underground Conductor – 50 Years

Table 8 provides a reference point by which to analyze the timing of asset health replacement needs for OTP. The Department notes that 362 Substation Equipment is also listed with a 45-year service life.[65]

[63] IR 29.
[64] *Ibid*.
[65] *In the Matter of Otter Tail Power Co.'s Petition for Approval of its 2024 Annual Review of Depreciation Certification*, Otter Tail Power Company, Report, April 4, 2025, Docket No. E017/D-24-302, (eDockets) 20254-217272-02.

The Department focuses its analysis on four main spending categories in OTP's Age Related Replacements and Asset Renewal Budget: Undergrounding, General Distribution Replacement, Substations, and Cut-Out Replacement. Collectively, these budget categories account for $37.7 million of OTP's non-WMP expenditures, which is equivalent to 57.8 percent of OTP's non-WMP budget.

E.2. Undergrounding Budget

OTP's 2025 to 2029 undergrounding budget is $16.7 million covering 12 projects, of which $10.9 million is composed of 4 Underground Replacement projects and $5.8 million is composed of 8 New Undergrounding projects.

The Department differentiates underground replacement projects from new underground projects on the basis of existing versus potential reliability improvements and cost. While the Department approves of OTP's strategy to select undergrounding projects that are at the end of life, which therefore should not trigger double payments on infrastructure, New Undergrounding projects can pose significant cost increases and should be evaluated for this cost effectiveness.

The Department recommends that all of OTP's New Undergrounding projects under its Age Related Replacement Budget undergo the same cost effectiveness analysis as undergrounding projects in the System Expansion or Upgrades for Reliability and Power Quality budget category.

OTP describes its Underground Asset Replacement projects as follows:

> Otter Tail Power has a large influx of 1970s vintage underground cable which is past its useful life and was highlighted in previous IDPs. In addition, un-jacketed, #2 Aluminum, Ridge-Lock, and flat strap cable designs have shown a history of failures and are in need of replacement. To proactively replace this cable and other failing underground cables, the annual UG replacement budget has been created. This budget is specifically for replacement of existing UG assets; largely UG cable. However, there are times when other UG equipment replacements may be warranted and included in the budget as well. Otter Tail Power's goal is to replace the at-risk cable identified for this program by the end of 2035. To prioritize the replacement spending, Area Engineers at Otter Tail Power utilize the following criteria:
>
> • Customers impacted
>
> • Prior record of cable failures
>
> • Historical reliability performance

- Cable vintage
- Cable type(s)
- Soil conditions
- Looped line vs radial line
- Constructability and/or access concerns[66]

OTP's four Underground Replacement projects will be evaluated on the basis of their age compared to OTP's depreciation values, which is listed at 50 years in Table 3. OTP does not provide this information in its IDP, and therefore the Department requests OTP to provide this information in its reply comments:

The Department requests that OTP present, in reply comments, an explanation of how old its four undergrounding projects are, and describe any reasons why each planned project is scheduled to be replaced before or after the 50 year depreciation period. The discussion should include OTP's criteria used to prioritize Underground Asset Replacement projects.

E.3. General Distribution Replacement Budget

OTP's 2025 to 2029 General Distribution Replacement budget is $9.6 million. OTP describes this budget category as follows:

> This budget is developed and funded annually to address very near-term and urgent failing components. Replacement spending is used for any immediate risk to safety and reliability. The following items are examples of projects that are included within the Replace budget:
>
> - Failed or tipped insulators
> - Distribution transformer replacements
> - Decayed/Damaged poles
> - Frayed conductor
> - Failed or weeping transformers
> - Failed substation components

[66] 2025 IDP —at 45.

> Projects funded under this budget are generally not identified years in advance. Instead, the budget is used for one-off replacement items that are identified throughout the year from visual inspections from field personnel.[67]

This budget category is reactive in nature and is likely composed of many small projects that would be difficult for OTP to report in its IDP. In order to analyze these expenditures, the Department covers OTP's inspection programs at the end of this section.

E.4. Substation Budget

OTP's 2025 to 2029 Substation budget is $7.4 million covering nine projects, of which $4.1 million is composed of five Rebuild projects, $2.0 million is composed of two Consolidation projects, and $1.3 million is composed of two New Substation projects.

OTP describes its Substation Replacement Budget as follows:

> This budget is designed for overall condition failures of substations and associated equipment. As stated in section 6, Otter Tail Power has 177 distribution substations in Minnesota system which are the start of the distribution delivery system and a key component of ensuring reliable service. Ensuring these substations are safe and reliable is a core part of the age-replacement spending plans.
>
> Projects within the budget include the examples below:
>
> • New rock or new fence to ensure access to substation is secure
>
> • New foundations
>
> • Substation access work
>
> • Complete substation rebuilds
>
> In addition to the same prioritization items noted as part of the UG program, the substation program also has additional weight placed on removal of Carte single phase substation transformers. These transformers have been failing prematurely and lead to long extended outages for customers and are a priority to replace. Carte transformers are very light-weight and mounted on wood pole platform substations, whereas new replacement transformers are heavier and require a concrete mounting

[67] *Ibid*.

> pad within the substation design. The permanent replacement generally requires a full substation re-build and often time re-location.[68]

OTP's nine substation projects will be evaluated on the basis of their age compared to OTP's depreciation values, which is listed at 45 years, as discussed in Section III.E.1. OTP does not provide this information in its IDP, and therefore the Department requests OTP to provide this information in its reply comments.

The Department requests that OTP present, in reply comments, an explanation of how old its nine substation projects are, and describe any reasons why each planned project is scheduled to be replaced before or after the 45 year depreciation period.

For OTP's two Consolidation and two New Substation projects, the Department seeks additional justification for why OTP is pursuing new and consolidated substations compared to replacing the substations like for like. The Department understands from OTP's IDP the general reasons why these projects are planned, however the Department seeks project-specific information.

The Department requests that OTP present, in reply comments, an explanation of why OTP's two substation Consolidation projects and two New Substation projects are necessary compared to replacing the substations like for like.

Finally, the Department analyzes OTP's substation projects based on their right-sizing. As discussed in Section III.C – Capacity, the Department does not have data on OTP's substation utilization at this time. Without this information, the Department assumes that OTP's substations are utilized to a similar extent to Minnesota Power (MP), based on a similar rural character, nearly flat load growth, and high Age-Related spending. The Department references its comments regarding substation right-sizing during asset replacement from its Initial Comments on MP's 2025 IDP, which state:

> The time to right-size MP's equipment is during asset replacement. Oversizing equipment protects against future upgrades, but it also increases costs in the near term because larger assets are more expensive. Given that the majority of MP's system is not capacity constrained, MP has an opportunity to right-size its old equipment to avoid paying for oversized system assets that may never be fully utilized. Right sizing equipment could spare MP's ratepayers from significant impacts that are expected from MP's Age Related Replacements and Asset Renewal budget. While the Department expects a significant portion of MP's budget to be covered by existing rates, the Department does not expect MP's spending plan to be fully covered by existing rates. MP's budget is 2-3 times higher than its

[68] 2025 IDP —at 45-46.

> historical spending, and this trend will be sustained for over a decade. In addition, transformer costs are several times higher than prices dating back just a few years ago, which means that existing rates will not sustain depreciation-level spending, let alone accelerated spending.[69] [citation omitted]

The Department requests that OTP explain, in reply comments, how the Company plans to address the risk of oversized system assets in its planned Age Related Replacements and Asset Renewal projects.

E.5. Cut-Out Replacement Budget

OTP's 2025 to 2029 Cut-Out Replacement budget is $4.8 million. An additional $3.9 million is marked for Cut-Out Replacements under the WMP.

OTP provides the following explanation for its Cut-Out Replacement Program:

> The SIRI Porcelain Cut-Out Replacement Program is intended to improve safety, reliability, and system performance by changing out distribution class porcelain cutouts to polymer cutouts. This program includes also installing wildlife protection materials on poles and distribution equipment, along with inspecting/tightening electrical equipment connections on selected distribution feeders. Legacy porcelain cut-outs have a history of failure in the field that cause safety and reliability concerns. Otter Tail Power has a goal to replace all porcelain cut-outs by year-end 2033.[70]

OTP provides very little detail about the need for this program in its IDP. Direct Testimony from Witness Riewer in OTP's 2025 Rate Case provides slightly more detail about the program:

> Legacy porcelain cut-outs have a history of failure in the field that cause safety and reliability concerns. By proactively replacing these legacy porcelain cut-outs, OTP is able to improve reliability. In addition, the installation of cover up and animal guard further prevents outages due to animal contacts and thus improves reliability. For example, OTP has over

[69] *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Department, Comments, March 13, 2026, Docket No. E015/M-25-140, (eDockets) 20263-229266-01, at 19.
[70] 2025 IDP —at 46-47.

> 300 animal contact-related outages per year across its distribution system.[71]

OTP's Cut-Out Replacement Program appears to be mostly proactive in nature. The Department expects that some of OTP's cut-out replacements currently happen under OTP's General Distribution Replacement budget when the cut-outs are at the end of their useful life. Therefore, the reliability benefits of proactively replacing cut-outs should be weighed against the deferral benefits of avoiding capital expenditures before the cut-outs are at the end of their useful life.

The Department recommends that the Commission require OTP to provide a cost benefit analysis of its Cut-Out Replacement Program in OTP's 2027 IDP that weighs the reliability benefits of the program against the deferral benefits of replacing cut-outs at the end of their useful life.

The Department is not opposed to OTP's plan to replace cut-outs with improved hardware at the end of a cut-out's useful life. The requested analysis intends to prove whether a proactive program for replacements is in the ratepayer interest.

E.6. Inspection Programs

The Department's primary interest in inspection programs and failure rates relates to the probability of equipment failure and resulting outage events. Inspection programs establish failure rates, and failure rates establish the cost of reliability. In IR 15, the Department asked OTP to describe its asset inspection programs. OTP responds as follows:

> 2. OTP completes annual distribution substation inspections. These inspections are used to evaluate substation condition and prevent larger reliability issues. OTP has historically completed opportunistic distribution inspections of the distribution system beyond the fence of the substation. OTP has recently instituted a new Advanced Distribution Line Inspection Program that is discussed in OTPs rate case in addition to continuing opportunistic inspections.
>
> a. OTP does not have failure rates by age.[72]

OTP's reference to its Advanced Distribution Line Inspection Program appears to pertain only to OTP's WMP.[73] Based on OTP's response to the Department Information Request 15, it appears that OTP does not have a robust inspection program established outside of its substations, and OTP does not track

[71] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota,* Direct Testimony of Michael J. Riewer, Otter Tail Power, October 31, 2025, Docket No. E017/GR-25-359, (eDockets) 202510-224484-12 (hereinafter: "Riewer Direct").
[72] IR 15.
[73] Riewer Direct— at 12.

failure rates as part of these inspection programs. Based on this information, the Department concludes on a preliminary basis that the relative size of OTP's General Distribution Replacement Budget, which is 5.0 percent of OTP's distribution budget, is explained by OTP's lack of inspections and regular replacement programs for its general distribution system. The opportunistic nature of OTP's inspections means that OTP either conducts these inspections when it has extra time, or waits until equipment fails to replace the infrastructure. Without information on failure rates, OTP does not know at what time it is most cost effective to replace OTP's infrastructure. The Department intends to address this issue further in OTP's 2027 IDP.

F. WILDFIRE

On October 31, 2025, the same day its IDP was filed, Otter Tail also filed its rate case, which includes wildfire spending for its 2026 test year.[74] Otter Tail witness Riewer discusses OTP's wildfire expenditures in two main IDP budget categories: Asset Health and Grid Modernization.[75] Riewer discusses that OTP has historically considered wildfire risk within its territory but not necessarily as directly as it does in its ongoing rate case and its current IDP.[76] Riewer discusses more frequent drought conditions in OTP's service territory and other environmental changes as causes for increased wildfire risk, and thus the Company's more direct consideration of wildfire in its regulatory filings.[77] Riewer also states, briefly, that credit rating agencies and insurance providers have both approached the Company regarding its wildfire mitigation strategies.[78] Riewer's testimony in OTP's rate case includes approximately $5.44 million in capital costs (which is an estimated $0.544 million revenue requirement) and $0.490 million related expenses, for a total of $1.034 million in wildfire-related Asset Health and Grid Modernization spends specific to Minnesota.[79] In its IDP, OTP includes $33.92 million in Wildfire Mitigation Program capital cost spending for next five years that is planned beyond existing rates; the spending for wildfire mitigation listed in the IDP will drive a need for additional cost recovery.[80]

It is important to note that wildfire mitigation expenditures are being considered in both the ongoing rate case and the IDP and highlights the Department's concern regarding sufficient record development on wildfire expenditures prior to cost recovery. As a new topic in both the IDP and the rate case, the Department is concerned that there has not been an opportunity—prior to the ongoing contested case—for stakeholders and regulators to consider the wildfire risk in Otter Tail's service territory and the adequate mitigation measures for proven risk. The Department, as it has stated in the other utilities' 2025 IDP proceedings, concludes that a contested cost recovery proceeding is not the

[74] Riewer Direct— at 8.
[75] Riewer Direct— at 4.
[76] *Id*., at 3.
[77] *Ibid.*
[78] *Ibid.*
[79] Riewer Direct —at 5-7; Department sum of OTP MN rows of Tables 1, 2, and 3.
[80] 2025 IDP— at 36 and Table 12.

location in which stakeholders and regulators should learn of and analyze wildfire expenditures for the first time. The Department concludes that initial review in the IDP process would allow for analysis by interested parties without the resource constraints imposed within a contested cost recovery case.

The Department understands that much of a utility's routine planning and operational practices work to mitigate wildfire—such as vegetation management practices to remove hazard trees and mitigate contact with utility infrastructure or regular pole inspection cadences. With the modifications to the IDP process as discussed throughout these comments, the Department believes the Company's distribution budget, relating to the business-as-usual categories, could be more properly evaluated and managed. The Department is concerned about the deviation from usual practice to address wildfire mitigation. If a utility, for example, is planning to enhance its routine vegetation management plan to expand the managed tract around its lines in response to increased wildfire risk, the project may result in a costly increase to the Company's distribution budget, specifically to address wildfire risk. The Department concludes that reporting on how the utility's routine distribution planning is addressing wildfire risk as well as proposals for programs to specifically address wildfire risk would aid in record development ahead of any potential cost recovery proceeding. Proposals should also include any proactive spending to expedite routine projects (i.e. replacement of fire-risk infrastructure before end of life) so that the cost effectiveness of such proactive planning can be evaluated by interested parties and regulators.

The Department was able to review OTP's Wildfire Mitigation Plan as attached to Riewer's direct testimony in the Company's current rate case.[81] OTP's Wildfire Mitigation Plan reads as a report of the Company's current practices, including the Company's wildfire risk assessment, but does not rise to the level of analysis and evidence for an eventual cost recovery proceeding that the Department is proposing for future plans. The Department envisions a utility's Wildfire Mitigation Plan to resemble a Transportation Electrification Plan. The plan would first include reporting on how the Company is quantifying and mapping risk, as well as how the risk is being mitigated by routine utility planning or operations. Next, should there be a proposal for additional spending to address wildfire risk specifically, the utility would include those proposals, including a full cost benefit analysis, in its plan for review by regulators and stakeholders. The Department finds OTP's Wildfire Mitigation Plan, as attached to Riewer's direct testimony, to be most similar to the reporting component of the Department's Wildfire Mitigation Plan proposal. Future Wildfire Mitigation Plans should be tailored to OTP's Minnesota territory, however.

The Department recommends that the Commission require Otter Tail to file its future (outside of the current rate case test year) Minnesota-specific Wildfire Mitigation Plan with the Commission as an attachment or supplement to its IDP. The Department recommends the Commission require OTP to include at least the following in its Wildfire Mitigation Plan:

[81] Riewer Direct— Schedule 2.

- **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).**
- **A definition of "wildfire" as it is used for utility identification, planning and mitigation.**
- **A discussion of its risk modelling, mapping and project prioritization process within its Wildfire Mitigation Plan.**
- **Quantification of actual wildfire risk in OTP's territory based on the probability and size of a fire, and land use.**
- **Wildfire risk should be compared to other reliability and safety risks as well as the wildfire risk experienced in OTP's other jurisdictions.**
- **Quantification of wildfire damages by event size, including OTP-owned and other property damage, applicable liability, and any other costs OTP deems reasonable to include.**
- **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.**
- **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.**
- **Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the approved wildfire mitigation measures, showing that wildfire-related outages in OTP's territory decreased by 50 percent; the average length of wildfire-related outage decreased by 20 percent.[82]).**
- **A full cost benefit analysis of any wildfire mitigation proposals.**

F.1. Wildfire Risk Assessment

Otter Tail commissioned a wildfire risk mapping initiative in collaboration with wildfire risk experts at EDM International, Inc. (EDM).[83] EDM developed a geospatial wildfire risk map tailored to OTP's operational footprint. OTP states its map integrates multiple national datasets—including LANDFIRE fuel models, USGS topography National Weather Service fire weather data, and U.S. Census population density—to assess and classify wildfire risk using adjective class ratings ranging from Very Low to Very

[82] Values are arbitrary given as examples for how OTP could demonstrate the efficacy of its wildfire mitigation plan.
[83] 2025 IDP— at 22.

High.[84] OTP states its adjective class ratings specify the potential for wildfire ignition and spread and are designed to support both strategic planning and real-time operational decision-making.[85]

According to OTP's Wildfire Mitigation Plan, EDM considered many factors in conducting the fire risk assessment, including historical fires, landcover fuel models, flame length intensity, elevations, slope, aspect, structures, population density, critical customers, and sensitive lands.[86] In describing EDM's process, OTP states:

> They performed the risk analysis by building a landscape model using 0.53-acre (30-meter) hexagons, evaluating the risk in each hexagon, and assigning appropriate risk attributes to each hexagon. We established boundaries by creating a five-mile buffer to each side of the centerline of and in a radius around our facilities. The table below, Figure 7, accounts for the land area (i.e., number of square miles) included in the landscape/population wildfire risk analysis by HFA risk classification and the associated percentages for each HFA rank.[87]

OTP includes the following table regarding the distribution of its identified hazardous fire areas (HFA).[88] It is important to note that OTP's wildfire mitigation plan is service-area-wide and includes parts of North and South Dakota as well as Minnesota. Throughout its wildfire mitigation plan attached to Riewer's direct testimony in the Company's ongoing rate case, OTP states it intends to focus mitigation measures in the moderate, high and very high HFA rank areas.

Table 9: HFA Distribution in OTP Service Area[89]

Table 2 - HFA Distribution in OTP Service Area

Fire Risk Levels		HFA Distribution	
Color	HFA Rank	Square Miles by HFA Rank	Percent Square Miles
	Fire Resistant	22,087.88	43.09%
	Very Low	15,781.93	30.79%
	Low	10,088.51	19.68%
	Moderate	1,953.20	3.81%
	High	993.38	1.94%
	Very High	355.71	0.69%
	Total	51,260.62	100.00%

[84] *Ibid.*
[85] *Ibid.*
[86] Riewer Direct— Schedule 2, at 17.
[87] *Id.*, at 18.
[88] Riewer Direct—Schedule 2, Table 2 – HFA Distribution in OTP Service Area, at 18.
[89] *Ibid.*

Otter Tail states its map varies from the FEMA map[90] because it evaluated additional factors specific to its service area, including the landscape, fire fuel, and urban interface and used more recent data sets. OTP states that its consultants used raw datasets from wildfirerisk.org (WRO) to create OTP's wildfire risk map and its outputs.[91] WRO datasets were created by the U.S. Department of Agriculture and the U.S. Forest Service at the direction of Congress to provide guidance and mitigation prioritization assistance to elected officials, land use planners, fire managers, and others.[92] OTP states it used the following baseline data in developing its wildfire risk map:

- Wildfire Hazard Potential (WHP): "An index that quantifies the relative potential for wildfire that may be difficult to control, used as a measure to help prioritize where fuel treatments may be needed" (WRO, 2024).

- Burn Probability (BP) (or Wildfire Likelihood): "The annual probability of wildfire burning in a specific location" (WRO, 2024).

- Conditional Flame Length (CFL): "Most likely flame length at a given location if a fire occurs, based on all simulated fires; an average measure of wildfire intensity" (WRO, 2024).

- Risk to Potential Structures (RPS) (or Risk to Homes): "A measure that integrates wildfire likelihood and intensity with generalized consequences to a home on every pixel. For every place on the landscape, it poses the hypothetical question, 'What would be the relative risk to a house if one existed here?'" (WRO, 2024).

- Housing Unit Risk (HU Risk): "This layer incorporates all primary elements of wildfire risk. It integrates wildfire likelihood and intensity with the generalized susceptibility of homes, and it also incorporates housing density" (WRO, 2024).[93]

As noted above, in relation to Otter Tail's identified HFA, the Otter Tail's wildfire mitigation plan is service-area-wide—including parts of North and South Dakota as well as Minnesota. The Department asserts that a Minnesota-specific assessment of wildfire risk, very similar to the service area wide analysis, would be necessary to develop the need, costs, and benefits of Minnesota-specific wildfire mitigation. The Department asserts that future WMP filed with OTP's IDP should include land use, HFA, and mapping specific to Minnesota.

[90] *Id*., at 16-17.
[91] *Id*., at 18.
[92] *Ibid*.
[93] *Id*., at 19.

F.2. Asset Health

Otter Tail plans to complete four wildfire mitigation projects focused on asset health spending within the 2025-2029 IDP forecasts:

> 1. Replace all distribution porcelain cut outs on WMP (wildfire mitigation plan) high risk feeders over the course of 3 years;
>
> 2. Ground line inspection of all distribution poles on WMP high risk feeders and mitigate any reject poles over the course of the next 4-5 years;
>
> 3. Bury all steel and copper distribution wire that transverses moderate, high and very high WMP areas over the course of approximately 5 years;
>
> 4. Replace all expulsion fuses with non-expulsion/vacuum fuses in 2026 in high wildfire risk areas.[94]

OTP states that its wildfire mitigations also provide "tremendous reliability benefits" in addition to wildfire risk reduction.[95] OTP state that its wildfire mitigation proposals, outside of the expulsion fuse program, already exist in its System Infrastructure and Reliability Improvement philosophy.[96] However, the additional spends identified here are aimed at proactively reducing wildfire event risk on the system.[97]

As discussed in subsections E.5. and E.2. of the present comments, the Department is concerned both about OTP moving forward with its proactive replacement of porcelain cutouts and its undergrounding of distribution wire without sufficient cost-benefit analyses. The Department understands that much of the work proposed to reduce wildfire risk would be completed eventually under the company's planning philosophy, however, proactive (before the assets reach end of life) replacement of equipment or undergrounding of distribution wire should be accurately weighed against replacement at the end of life.

In its rate case, OTP witness Riewer discusses the Company's proposed wildfire-related porcelain cut-out replacement program work for its 2026 test year.

> When porcelain cut-outs begin to fail, they are prone to insulation leakage. When insulation breaks down in this manner, it is more likely to create pole fires when current conducts through wooden structures. […] OTP has approximately 5,500 cut-outs that are located on distribution feeders that

[94] 2025 IDP— at 47.
[95] *Ibid.*
[96] *Ibid.*
[97] *Ibid.*

> transverse moderate, high, and very high wildfire risk areas. The 2026 plan will address approximately 1,800 of these cut-outs. The remainder will be completed in 2027 and 2028.[98]

Also in the ongoing rate case are expenditures for undergrounding several miles of steel and copper wire that traverses wildfire risk areas in 2026.

> For the wildfire risk portion of the distribution undergrounding program, OTP will be focusing on replacement of copper and steel wire. Copper and steel wire is a known safety and reliability issue within the distribution system because of its age and deteriorated condition. Such wire is often older and in worse condition because it has not been a part of construction and engineering standards for some time. If it fails, it can contribute to ignitions. […] OTP has identified approximately 60 miles of copper and steel distribution line that is located in moderate, high, and very high risk areas. OTP plans to complete approximately 12 miles of steel and copper replacement with underground cable in 2026 within the highest risk areas first. The remaining miles will be replaced thereafter. As OTP refines project scopes for these 60 miles, it's possible some segments may remain overhead for numerous reasons but will be updated with modern cable that is less prone to failure.[99]

OTP's non-expulsion fuse replacement program is specific to the 2026 test year and will focus on replacing approximately 600 traditional fuses located moderate, high and very high wildfire risk areas.[100] OTP explains that traditional fuses are acceptable for use throughout most of the distribution system, however, because a traditional fuse expels heated materials when it operates, a traditional fuse may be a source of ignition in higher fire risk areas. OTP intends to reduce the risk of ignition by replacing traditional fuses with non-expulsion vacuum fuses.[101]

Further, OTP discusses its accelerated ground line inspection plan for its distribution poles in its rate case. The Company intends to complete a ground line inspection of all distribution poles in wildfire risk areas over the next 4-5 years that have not been inspected in that past 10 years.[102] The ground line inspection of distribution poles will include 25,000 total poles and the mitigation of any reject poles that do not meet the strength tests.[103] OTP states that accelerated inspection in wildfire risk areas is

[98] Riewer Direct— at 8.
[99] *Id*., at 13-14.
[100] *Id*., at 15.
[101] *Id.,* at 14-15.
[102] *Id.,* at 13.
[103] *Ibid*.

necessary because, during high wind events, a pole failure can present a high risk of a utility-caused ignition.[104]

Because these mitigation measures are being evaluated in the ongoing rate case, the Department will not offer recommendations in the present comments. However, as mentioned above, the Department asserts that review of wildfire plans and wildfire mitigation proposals should begin in the IDP before the Company proceeds to a rate case for cost recovery. The Department concludes that the IDP is a more accessible venue for stakeholders, and, at its core, is a docketed location for record development on distribution-related expenditures like wildfire mitigation.

F.3. Grid Modernization

The Company's grid modernization initiatives include the deployment of electronic grid reclosers and the development and deployment of a distribution SCADA (dSCADA) system.[105]

OTP plans to prioritize hazardous fire areas for the deployment of electronic reclosers.[106] Otter Tail has identified 101 distribution feeders with oil circuit reclosers located in hazardous fire areas presenting the most wildfire risk.[107] Otter Tail states that oil circuit reclosers are oil insulated devices requiring more maintenance than newer vacuum bottle technology devices.

> These Next Gen electronic reclosers are an upgrade both from a maintenance improvement standpoint as well as improved protection options, and provide engineers with advanced overcurrent coordination flexibility, access to system data such as fault distances, load levels, voltage magnitudes, harmonic content, etc. These are all used to better plan and assess the health of the system to ensure optimal reliability for customers.[108]

OTP plans to target the identified 101 feeders for proactive replacement of oil circuit reclosers with electronic reclosers.[109] OTP anticipates the conversion will take place over the next 6 years.[110]

Otter Tail provides very little discussion of its dSCADA system in the IDP. OTP states that its dSCADA system will enable the Company to monitor and control key Intelligent Electronics Devices across the distribution network.[111] Otter Tail states that when paired with electronic reclosers, the dSCADA

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[104] *Ibid.*
[105] 2025 IDP— at 42.
[106] *Ibid.*
[107] *Ibid.*
[108] *Ibid.*
[109] *Ibid.*
[110] *Ibid.*
[111] *Ibid.*

system will "significantly improve our ability to proactively identify and mitigate wildfire risk(s) to improve the safety and reliability of our ageing electric distribution system."[112]

Otter Tail's ongoing rate case includes both the dSCADA system and a portion of the electronic recloser replacement plan.[113] OTP witness Riewer states that work on the dSCADA system will start in 2026 with development; full deployment of the system is slated for between 2027 and 2028.[114] As stated in the IDP, Riewer explains that the electronic recloser replacement program will happen over 6 years, however Riewer provides additional detail in that approximately 16 reclosers will go into service in 2026.[115] Riewer states OTP's grid modernization program allows OTP to remotely initiate non-reclose functions instantly, rather that dispatching crews to each substation in the affected area. Riewer states that SCADA provides continuous monitoring and allows OTP to proactively identify device failures before the faulty device is called on to operate.[116] Riewer states that electronic reclosers will allow the Company additional flexibility to respond to wildfire conditions as faster trip settings or alternative protection algorithms could be enabled to identify faults more rapidly.[117]

The Department will not provide a recommendation regarding Otter Tail's grid modernization investments related to wildfire mitigation in the present docket because the investments are being evaluated in the Company's ongoing rate case. The Department reiterates the importance of more fulsome wildfire mitigation plans within the IDP going forward.

F.4. Actual Fire Data

It is important to ground OTP's WMP request in actual fire data.

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112 *Ibid.*
113 Riewer Direct— at 16.
114 *Ibid.*
115 *Ibid.*
116 *Id.,* at 17.
117 *Ibid.*

Table 10**:** Summary of OTP Outages by Cause and Frequency in 2023 and 2024

2023 – MN Distribution Outages by Cause

Cause	Outage Count
Material or equipment failure	303
Squirrel	213
Maintenance	203
Weather	201
Tree on the line	156
Cause unknown	143
Public	120
Animal caused, not squirrel	51
Equipment fault or operation	24
Fire	10
Downstream customer issue	10
2023 Total	1434

2024 – MN Distribution Outages by Cause

Cause	Outage Count
Maintenance	220
Material or equipment failure	217
Squirrel	177
Tree on the line	167
Cause unknown	156
Weather	129
Public	108
Animal caused, not squirrel	35
Fire	19
Downstream customer issue	14
Equipment fault or operation	10
2024 Total	1252

Source: IR 5

In 2023, OTP experienced 1,434 outages and 10 of these outages were caused by fire, which is equivalent to 0.7 percent of all outages, which was OTP's least frequent cause of outages. In 2024, OTP experienced 1,252 outages; 19 of these outages were caused by fire, which is equivalent to 1.5 percent of all outages—or OTP's third-least frequent cause of outages.

In OTP's response to the Department Information Request 5, OTP provides additional data on fire outages. **[TRADE SECRET HAS BEEN EXCISED]**

Given these initial estimates, wildfire does not appear to be a significant risk to OTP's system.

The fire outage cause does not mean that the outage was caused by a wildfire. Fire outages could be sourced from domestic sources (building fires), equipment failure, or other sources. The data presented from IR 5 does not differentiate by the type of fire. Therefore, the Department requests OTP to further explain the cause of its fire outages.

The Department requests that OTP present in its reply comments a breakdown of all fire outages caused by wildfire compared to all fire outages caused by any other means. OTP should outline which specific outages in IR 5 correspond to actual wildfires.

In addition, in order to facilitate a public discussion of OTP's dataset in IR 5:

The Department requests that OTP un-redact, as appropriate, the Department's trade secret summary of OTP's outage data from IR 5.

G. PLANNED GRID MODERNIZATION INITIATIVES

The Department responds to the following notice topic:

> *Notice Topic 3.B: Feedback, Comments, and Recommendations on Planned Grid Modernization Initiatives.*

In OTP's response to the Department Information Request 14, OTP provides a summary of its Grid Modernization Projects and their respective budgets, which is shown in Table 11. OTP's AMI,[118] Advanced Load Management (ALM)[119] and UM-Morris Battery[120] projects are all analyzed in other dockets and OTP's WMP is analyzed in the previous section. The remaining Electronic Reclosers and LED Lighting projects are not analyzed in these comments due to their smaller budgets.

Table 11: Summary of OTP's Grid Modernization Projects

Project Name	5-Year Forecast (2025-2029)
AMI	$6,837,055
Advanced Load Management – ALM	$18,329,174
Electronic Reclosers – non WMP	$900,000
Electronic Reclosers and SCADA – WMP	$10,776,667
LED Lighting	$750,000
UM-Morris Battery	$2,900,217

[118] See Docket No. E017/M-23-131.
[119] See Docket No. E017/M-24-186.
[120] See Docket No. E017/M-25-325.

H. NON-WIRES ALTERNATIVES ANALYSIS

The Department responds to the following notice topic:

> *Notice Topic 3.A: Feedback, Comments, and Recommendations on Non-Wires Alternative Analysis.*

As a part of the NWA analysis, OTP must:

> provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.[121]

Additionally, OTP is required to include:

- Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
- A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
- Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed.
- A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.[122]

Overall, much of OTP's NWA discussion mirrors that of its 2023 IDP.[123] In its 2025 IDP, OTP reports that the Company "does not have any distribution load increase driven capacity upgrade projects within the 5-year forecast which are above the $2M threshold requiring a non-wire alternative analysis."[124]

H.1. Project Types

Based on the information provided by OTP, the Department assumes that the projects the Company considers for its NWAs are capacity related.[125] However, OTP provides minimal detail on NWA project

[121] February 20, 2019 Order – at 6-7.
[122] *Id*., at 7.
[123] 2023 IDP at 47-48.
[124] 2025 IDP – at 47.
[125] *Ibid*.

types beyond a reference to its "longstanding history of utilizing non-wire alternatives through our demand response and ECO programs."[126]

If OTP only considers capacity projects, the Department believes that the Company can expand its analysis to address needs beyond capacity.

> In its 2025 IDP, Minnesota Power (MP) states: A non-wires solution may also be suitable to improve reliability by enhancing circuit backup capability in situations where large capital costs projects are needed to create external backup sources. In that case a non-wires solution like a BESS can provide backup power during unplanned outages until crews restore service.[127]
>
> Moreover, MP includes in its 2025 IDP conditions under which NWA projects can be used to improve reliability.[128] In the Cloquet NWA solution, MP applies a FLISR analysis to identify optimal locations for reclosers and sectionalizers to automate switching and limit customer exposure to feeder faults.[129] As MP provides an analysis and example of a reliability project, the utility demonstrates that NWAs can address more than capacity projects.[130]

Therefore, the Department finds the OTP should consider reliability projects if it does not already do so.

The Department requests that OTP, in reply comments, clarify and describe the types of projects it considers for its NWA analysis.

H.2. NWA Analysis Process

Order Point 3 of the Commission 2023 IDP Order also "directs Otter Tail to submit in its next IDP its process for Non-Wires Alternatives analysis."[131] Upon review of OTP's NWA discussion, the Department is uncertain of what Otter Tail's process for its NWA analysis is.

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[126] 2025 IDP – at 48. See 2023 IDP– at 32.
[127] *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Minnesota Power, November 3, 2025, Docket No. E015/M-25-140, (eDockets) 202511-224624-01, at 70.
[128] *Id*., at 71.
[129] *In the Matter of Minnesota Power's 2023 Integrated Distribution Plan*, Minnesota Power, October 16, 2023, Docket No. E015/M-23-258, (eDockets) 202310-19614-01, at 72.
[130] Department Initial Comments on Xcel's 2025 IDP – at 99.
[131] 2023 IDP Order – at 6.

The Department requests that OTP, in reply comments, describe the Company's process for its NWA analysis.

H.3. Morris Flow Battery Project

In its 2025 NWA discussion, Otter Tail Power provides an update on the Morris Flow Battery Project as directed by the Commission.[132] The Department finds that OTP has met the Morris Flow Battery Project reporting requirement.

I. DISTRIBUTED ENERGY RESOURCE (DER) SCENARIOS AND FORECASTS

The Department responds to the following notice topic:

> *Notice Topic 3.D: Feedback, Comments, and Recommendations on Distributed Energy Resources (DER) Scenarios and Forecasts*

The Department does not have any comments on this notice topic.

J. TEP

OTP filed its Transportation Electrification Plan (TEP) as a supplemental filing to its IDP.[133] OTP does not propose any new programs in its 2025 TEP and instead focuses on the TEP filing requirements and associated Commission orders. Further, OTP is not requesting certification of any project in the TEP filing because "[r]ecovery requests for the projects discussed are currently within other dockets."[134] The Department's comments on the TEP focus on notice topics five through eight.

J.1. TEP Filing Requirements

The Department responds to the following notice topic:

> *Did Otter Tail Power adequately address the Commission's TEP filing requirements and prior Orders, as outlined in Attachment A to this notice?*

OTP's TEP is structured to address each of the filing requirements from the Commission's December 8, 2022 Order[135] and the Commission's June 3, 2025 Notice of Approval of Updated Filing

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[132] *Ibid*.
[133] *In the Matter of the Distribution System Planning for Otter Tail Power Company- Transportation Electrification Plan,* Otter Tail Power Company, October 31, 2025, Docket No. E017/M-25-141, (eDockets) 202511-224606-02 (hereinafter "2025 TEP").
[134] *Id*., Filing Cover Letter.
[135] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure and In the Matter of Distribution System Planning for Otter Tail Power Company, Order*, December 8, 2022, Docket Nos. E-999/CI-17-879 and E017/M-21-612, (eDockets) 202212-191192-01

Requirements.[136] The Department has reviewed OTP's TEP in its entirety and concludes that OTP has addressed each of the TEP filing requirements of the aforementioned Orders.

In addition, the Department analyzes OTP's TEP under the relevant statute, Minn. Stat. § 216B.1615.[137] Subdivision 1 of Minn. Stat. § 216B.1615 defines relevant terms. Subdivision 2 defines the contents of the TEP that public utilities are required to file. Subdivision 3 gives the Commission the authority to approve, modify, or reject a TEP and the rubric under which the decision is to be made. Finally, subdivision 4 of the statute gives the Commission authority to approve cost recovery under Minn. Stat. § 216B.16[138] for investments made and expenses incurred under an approved plan.

The Department also recognizes the importance of electrifying Minnesota's transportation sector consistent with the Commission's February 1, 2019 Order in Docket No. E999/CI-17-879 ("EV Inquiry Order"):

> 1. Electrification Is In Public Interest: The Commission finds that electrification of Minnesota's transportation sector can further the public interest in:
>
> > a. *Affordable, economic electric utility service* by improving utility system utilization/efficiency and placing downward pressure on utility rates through increased utility revenues and better grid utilization;
> > b. *Renewable energy* use by increasing electricity demand during hours when renewable energy is most prevalent on the system and developing tariffs that correlate renewable energy resources to electric vehicle charging; and
> > c. *Clean energy* by reducing statewide greenhouse gas and other environmentally harmful emissions.[139]

J.2. Statutory Criteria

J.2.1. Minn. Stat. § 216B.1615, subd. 3(1)

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[136] *In the Matter of Otter Tail Power's 2025 Integrated Distribution Plan, Notice of Approval of Updated Filing Requirements*, June 3, 2025, Docket Nos. E017/CI-18-253, E017/M-23-380, and E017/M-25-141, (eDockets) 20256-219519-01, at Order Point F.
[137] Minn. Stat. § 216B.1615 (2023).
[138] Minn. Stat. § 216B.16 (1sp2025)
[139] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Order Making Findings and Requiring Filings,* February 1, 2019, Docket No. E999/CI-17-879, (eDockets) 20192-149933-01, (hereinafter: "EV Inquiry Order") at Order Point 1.

Minn. Stat. § 216B.1615, subd. 3(1) requires Commission consideration of whether the TEP proposals are reasonably expected to "improve the operation of the electric grid."

The Commission's EV Inquiry Order established that transportation electrification "can further the public interest in affordable, economic electric utility service by improving utility system utilization/efficiency and placing downward pressure on utility rates through increased utility revenues and better grid utilization."[140] The Commission also established that optimized EV integration includes charging during periods of low demand and high renewable energy generation and promoting load management.[141]

OTP discusses that managing EV loads remains a priority for the Company; Otter Tail states it has promoted off-peak rates to customers to align charging with low-cost energy periods.[142] Otter Tail is excited about its Advanced Metering Infrastructure project which will provide the Company and customers with interval metering data. Once the meter deployment is completed, the Company looks forward to leveraging its residential time of day pilot to encourage customers to move EV charging to low-cost time periods and to avoid the upfront costs of a second meter to measure EV charging or other off-peak usage.[143] OTP states participant enrollment is underway for its residential time of day pilot that is scheduled to begin by the end of 2025.[144]

Otter Tail also discusses its $500 rebate through its ECO triennial plan (2026-2026) for any hardwired level 2 charger installed on an off-peak rate. The Company also notes its recently approved EV load management credit rate option that targets customers with only a general service meter—the rate allows the customer to participate in managed EV charging and earn a credit without the need for installation of a second meter.[145] Otter Tail states the EV load management credit rate will allow the Company to better manage the electric grid and avoid energy purchases during high price periods that impact all customers' energy costs; specifically, OTP states, this type of load management allows for more dynamic control that allows for daily variance in timing to optimize for market conditions.[146]

The Department concludes OTP has satisfied this criterion.

J.2.2. Minn. Stat. § 216B.1615, subd. 3(2)

Minn. Stat. § 216B.1615, Subd. 3(2) requires Commission consideration of whether the TEP proposals are reasonably expected to "increase access to the use of electricity as a transportation fuel for all

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[140] EV Inquiry Order —at Order Point 1.a.
[141] *Id*., at Order Point 3.
[142] 2025 TEP— at 5.
[143] Id., at 5.
[144] *Ibid.*
[145] *In the Matter of Otter Tail Power Company's 2023 Integrated Distribution Plan, Commission Order*, February 3, 2026, Docket No. E017/M-23-380, (eDockets) 20262-227791-01.
[146] 2025 TEP— at 4.

customers, including those in low- and moderate-income communities, rural communities, and communities most affected by air emissions from the transportation sector."

Otter Tail cites its ECO portfolio in its TEP, which includes programs to expand outreach about electric transportation. OTP states it offers rebates for new and used battery electric vehicles, new and used plug-in hybrid vehicles, and electric school buses through its ECO program. Other OTP ECO programs include rebates for hardwired level 2 chargers installed on an off-peak rate and electric panel rebates for upgrades to ensure a customer's electric service is large enough for the addition of EV charging.[147] As mentioned above, OTP also has a soon-to-launch residential time of day rate and a newly approved EV load management credit rate. Each of which allows a customer to participate in off-peak charging without the costs to install a second, off-peak meter.
OTP also engages in educational outreach initiatives to provide community members, and auto dealers with information about the Company's programs and to answer questions about charging solutions and EV technology.[148]

Otter Tail states that it is exploring a commercial level 2 charging option, as well as multi-family and low-income electric vehicle charging options for the next TEP and the next ECO Triennial Plan, respectively.[149] Otter Tail states it has begun testing a lower cost level two charging option that contains billing capabilities for commercial, multifamily, and low-income programs that would be utilized in any proposed plan.[150]

Otter Tail states that there are only 270 customer-owned electric vehicles in the Company's Minnesota Service territory as of filing the TEP. Of those, 169 are battery electric vehicles and 101 are plug-in hybrid electric vehicles.[151] The Company explains that its territory is very rural and spread-out, limiting adoption and the impacts of added load.[152] The Department acknowledges the location of Otter Tail's service territory, but asserts that the Company, through its EV programs, can have an impact on EV adoption and charging behavior in its territory. The Department notes that, because most charging is done at home, access to home charging could be a barrier for OTP customers, especially in rural, spread-out communities that often lack public transportation infrastructure.

The Department requests that OTP, in reply comments, update tables 1 and 2 of its TEP[153] to indicate the number of and expenditures related to level 2 charger rebates provided by the Company in the last five years and the planned rebates for the next five years.

[147] 2025 TEP— at 1-2.
[148] *Id*., at 2.
[149] *Ibid.*
[150] *Ibid.*
[151] *Id*., at 9.
[152] *Id.,* at 16.
[153] *Id*., at 8.

J.2.3. Minn. Stat. § 216B.1615, subd. 3(3)

Minn. Stat. § 216B.1615, subd. 3(3) requires Commission consideration of whether the TEP proposals are reasonably expected to "increase access to publicly available electric vehicle charging for all types of electric vehicles."

OTP provides Table 3 in its TEP, which lists 19 known publicly accessible Level 2 charging stations with a total of 32 plugs.[154] Otter Tail states it has actively supported electric vehicle education and awareness initiatives that have resulted in partnerships with interested site locations in installing public level 2 charging stations. In these partnerships, OTP provided a level 2 charger to be installed by the site host and assists with education and equipment selection.[155] The partnerships have resulted in publicly available chargers being installed in Level 2 chargers in Crookston, Bemidji, Fergus Falls, and Morris.[156] The Company also notes that its EV charging infrastructure has installed 2 of 10 level 2 chargers that will be installed in communities to expand the Company's education and awareness outreach activities. The two chargers that have been installed are located in Frazee and Canby.[157]

OTP states that a main roadblock to increasing installations is the need for billing capabilities and the overall cost of the previously available options. Otter Tail states that it is currently testing level 2 chargers that have networked billing capabilities and lower upfront costs at its Fergus Falls campus. Otter Tail believes that the reduced upfront costs of the chargers it is testing may contribute to increased customer installations of level 2 chargers and partnerships for the remaining eight education sites.[158]

The Company also provides Table 4 of its TEP listing the known publicly accessible direct current fast charging stations. The Company lists 7 publicly available fast chargers. OTP states that it has four DCFC on its DCFC service time-of-day pilot rate.[159] The Company has received very few requests for DCFC installations outside of a NEVI application request.[160]

The Department concludes that OTP has satisfied this criterion.

J.2.4. Minn. Stat. § 216B.1615, subd. 3(4)

Minn. Stat. § 216B.1615, subd. 3(4) requires Commission consideration of whether the TEP proposals are reasonably expected to "support the electrification of medium-duty and heavy-duty vehicles and associated charging infrastructure."

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[154] *Id*., at 12.
[155] *Ibid.*
[156] *Ibid.*
[157] *Ibid.*
[158] *Ibid.*
[159] Id., at 13.
[160] *Ibid.*

Otter Tail states that most of its fleet electrification has occurred at public schools with electric school buses.[161] OTP serves three electric school buses currently, all of which received funding through state and federal funding opportunities. OTP states it also offers a $5,000 rebate through ECO for electric school buses.[162]

OTP states it was notified in October of 2024 that it was awarded funding from the DOE for Smart Grid initiatives. Part of the funding would have been for eight electric buses and the accompanying infrastructure to pilot a “school network” that would allow neighboring schools to utilize the electric buses to transport students participating in extracurricular activities.[163] The grant was terminated by DOE in 2025 with the determination that:

> “[t]his project does not effectuate the Department of Energy’s priorities of ensuring affordable, reliable, and abundant energy to meet growing and/or address the national emergency declared pursuant to Executive Order 14156 […] this project is not consistent with this Administration’s goals, policies or priorities.”[164]

Beyond the electric school buses in its territory, OTP reports that no other transit, medium- or heavy-duty electric vehicles are known within its territory.[165] The Company also cites projects at its customer service centers in discussing fleet electrification. Company employees are encouraged to drive OTP electric fleet vehicles while attending off-site meetings to become more familiar with the tech and be more informed when speaking with customers. The Company has installed EV chargers at its customer service centers to ensure employees can utilize the technology when travelling between OTP communities for meetings.[166] The Company is also working on installing chargers for employee personal vehicles as a test case for new level 2 charging equipment.[167]

The Department concludes OTP has satisfied this criterion.

J.2.5. Minn. Stat. § 216B.1615, subd. 3(5)

Minn. Stat. § 216B.1615, subd. 3(5) requires Commission consideration of whether the TEP proposals are reasonably expected to “reduce statewide greenhouse gas emissions, as defined in section 216H.01, and emissions of other air pollutants that impair the environment and public health.”

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161 *Id.,* at 4.
162 *Ibid.*
163 *Ibid.*
164 *Ibid.*
165 *Id*., at 9.
166 *Id*., at 6.
167 *Ibid*.

The Department found very little discussion of emission reductions in OTP TEP, as required by Minn. Stat. § 216B.1615, subd. 3(5).

The Department requests that OTP discuss, in reply comments, how its Transportation Electrification portfolio addresses the requirement of Minn. Stat. § 216B.1615 subd. 3(5).

J.2.6. Minn. Stat. § 216B.1615, subd. 3(6)

Minn. Stat. § 216B.1615, subd. 3(6) requires Commission consideration of whether the TEP proposals are reasonably expected to "stimulate nonutility investment and the creation of high-quality jobs for local workers."
OTP has both a rebate for hardwired level 2 chargers installed on an off-peak rate and an electrical panel upgrade rebate. By following a rebate structure rather than a utility-owned infrastructure structure, a customer is allowed to seek out the local electrical contractor of their choice to complete the work.

The Company also states that it continues to evaluate a make-ready program for public DC fast chargers. OTP explains that the make-ready program will involve utilities extending infrastructure beyond the meter—such as transformers, underground line extensions, and mounting pads—to reduce capital costs for third-party developers. All infrastructure beyond the metering point would need to be contracted out, offering, OTP states, no cost savings aside from the capital contribution itself.[168] The Company is exploring other options for the make-ready program, such as leveraging the Company's approved Electrical Service Agreement, which includes a three-year revenue guarantee which would allow the Company to recover costs for line extensions and transformers if customer revenue thresholds are met.[169] If the make-ready structure is maintained when the program is ultimately proposed, the Department reiterates that the work on the customer side of the meter will allow customers to choose the contractor of their choice.

The Department concludes that OTP satisfied this criterion.

J.2.7. Minn. Stat. § 216B.1615, subd. 3(7)

Minn. Stat. § 216B.1615, subd. 3(7) requires Commission consideration of whether the TEP proposals are reasonably expected to "educate the public about the benefits of electric vehicles and related infrastructure."

Otter Tail provides a summary of its EV education initiatives in its TEP. OTP states that the Company attends several ride and drive events in collaboration with local utilities, businesses, and community

[168] *Id*., at 2-3.
[169] *Ibid.*

members.[170] OTP states that the events usually target the residential sector and cover the latest technologies, financial outlook, and utility charging offerings.[171] The interest on the Commercial side mostly comes from public schools interested in funding opportunities for electric school buses. OTP states that it educates schools on rate options, charger installation options and estimated energy costs.[172] The Company also states it utilizes social media to feature EV related events, news, and information during its "drive electric week."[173]

The Department concludes that OTP satisfied this criterion.

J.2.8. Minn. Stat. § 216B.1615, subd. 3(8)

Minn. Stat. § 216B.1615, subd. 3(8) requires Commission consideration of whether the TEP proposals are reasonably expected to "be transparent and incorporate reasonable public reporting of program activities, consistent with existing technology and data capabilities, to inform program design and commission policy with respect to electric vehicles."

Otter Tail provides public reporting in several dockets, including its annual EV report in docket no. E017/M-20-181, and docket no. E999/CI-17-879. OTP is also subject to the reporting requirements of ECO to the extent that its EV-related rebates are part of its ECO triennial plans.

The Department concludes that OTP satisfied this criterion.

J.2.9. Minn. Stat. § 216B.1615, subd. 3(9)

Minn. Stat. § 216B.1615, subd. 3(9) requires Commission consideration of whether the TEP proposals are reasonably expected to "reasonably balance the benefits of ratepayer funded investments in transportation electrification and impacts on utility rates."

Transportation electrification in OTP's territory is in a relatively nascent state. Otter Tail explains that there are 270 customer-owned EVs in the Company's territory and, outside of electric school buses, there have not been any transit, medium- or heavy-duty EVs in the Company's territory.[174] The Company states that the characteristics of its territory (rural and spread out) limit EV adoption and the impacts to the system of added load.[175] The Company notes that as adoption eventually increases and the impacts of the added load increase, system upgrade costs may become more of an issue.[176] Due to the relatively early phase of transportation electrification in Otter Tail's territory, the Department is

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[170] *Id*., at 6.
[171] *Ibid.*
[172] *Ibid.*
[173] *Id.,* at 6-7.
[174] *Id*., at 9.
[175] *Id*., at 16.
[176] *Ibid.*

not immediately concerned that the Company's TEP portfolio is causing an imbalance of ratepayer investments and utility rates.

However, OTP's Table 2, depicting five-year future spending on all transportation electrification initiatives, presents quite a range of potential spending on things such as O&M Charging Infrastructure expenditures and ECO Rebate expenditures.[177] The Department concludes that greater discussion of the variability of transportation electrification spending would be helpful.

The Department requests that OTP, in reply comments, explain the range of anticipated future transportation electrification spending depicted in its Table 2.

J.2.10. Minn. Stat. § 216B.1615, subd. 3(10)

Minn. Stat. § 216B.1615, subd. 3(10) requires Commission consideration of whether the TEP proposals are reasonably expected to "appropriately balance the participation of public utilities and private enterprise in the market for transportation electrification and related services."

This statutory criterion primarily implicates public charging infrastructure and the risks associated with investor-owned utility investments in this market, up to and including utility ownership of EV charging stations. As discussed above, OTP directly serves the public charging market with its DCFC project. Accordingly, the Commission's IDP filing requirement 3.E.5 requires OTP to discuss divestment strategies for its DCFC sites as the conclusion of the pilot program. The Department discusses potential concerns with the Company's DCFC pilot further below (subsection B.4.1 of the present comments).

J.3. Equitable Customer Outcomes

The Department responds to the following notice topic:

> *Are there gaps in Otter Tail Power's transportation electrification programs the Commission should address to ensure equitable customer outcomes?*

At the current stage, OTP's equity-related commitments in the 2025 TEP are, like transportation electrification in its territory, still nascent. The Company states that it has no specific multi-family offering yet and has not received any requests from multi-family housing customer tenants or landlords with a request to install charging options in multi-dwelling units. While OTP states that it "does not currently have any specific multi-family offerings that are differentiated from its offerings to all residential customers," it is "reviewing multi-family and low-income electric vehicle charging options to be included in the Company's 2027-2029 ECO plan to directly target barriers to adoption for

[177] *Id.,* at 8.

this sector of customers."[178] The Department notes that the absence of requests may itself reflect barriers: split incentives between landlords and tenants, lack of billing capability, lack of clear turnkey options, and limited customer awareness. The Company's current testing of a lower-cost networked Level 2 charging option that could be used for commercial, multi-family, and low-income programs is therefore promising.[179]

OTP's rural service territory brings about a different set of challenges. The Department views that equitable customer outcomes in rural service areas are not only a question of income, but also a question of distance, market absence, and limited private sector deployment. With regards to that, the Department appreciates OTP's DCFC buildout. However, gaps and opportunities exist in increasing affordability and durability of the EV projects in the 2025 TEP. The Company explains that many DCFC sites are not generating enough revenue to cover O&M, which raises long-term sustainability concerns. If these sites become increasingly expensive to maintain without commensurate use, OTP's customers could face a challenge where the infrastructure exists, but the business model remains fragile.

J.4. Other Issues

The Department responds to the following notice topic:

> *Are there other issues or concerns related to this matter?*

J.4.1. DCFC Pilot

The Company explains that, in its DCFC Pilot, the usage revenues often do not offset standard O&M costs. OTP explains:

> The current limitation of a majority of network and maintenance services is that they are based on set rates that do not effectively scale with usage. Until usage revenues exceed O&M costs, the sites lose money and long-term success for any divestment partner would be limited, potentially resulting in the decommission of the site.[180]

The Department identifies that the current rate issue to be significant because it bears directly on whether utility-owned DCFC is a transitional market-making tool or a longer-term regulated asset class in areas unattractive to private developers. OTP also projects a potentially large future capital range of $2 million to $5 million (see Table 2) in the next five years for DCFC infrastructure upgrades if divestment proves non-viable.

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[178] 2025 TEP – at 2.
[179] *Ibid.*
[180] *Id.*, at 6.

The Department requests that OTP, in reply comments, provide a five-year cost-benefit projection of its DCFC fleet, detailing rural-specific fixed and variable maintenance costs alongside targeted utilization strategies to improve revenue ratios. This analysis must include a clear roadmap toward financial self-sufficiency to protect non-EV-driving ratepayers from long-term O&M subsidies.

Table 12**:** OTP Table 2- Budget allocation for the next 5-years on all transportation electrification initiatives, broken down across the sections of its budget.

Budget Category (Distribution, IT, Transmission, etc.)	Capital	Expenditure
MN EV DCFC Infrastructure Upgrade*	$2,000,000 - $5,000,000	
Marketing and Communication		$50,000 - $250,000
NEVI Support	< $50,000	
O&M Charging Infrastructure		$50,000 - $250,000
ECO Rebates – off peak charging, electric vehicles, electric school buses		$100,000 - $500,000

*Estimate of potential upgrade cost for improving charging sites if divestment is considered a non-viable option.

J.4.2. EV Load Management Program

The Company proposed a new EV Load Management Rate,[181] an EV Credit Rider, that is designed to reduce both upfront installation costs and lower electricity bills for participants. The Petition, in Docket No. E-017/M-23-380 was recently approved by the Commission. OTP proposed a monthly bill credit of $9 for single Level 2 and $13 for multiple level L2 chargers. In its Petition, the Company writes:

> [t]he proposed charging credit is designed to target customers who only have a residential or farm service meter at their residence. There are several factors that might deter customers from installing a second off-peak service or switching to a time-of-day rate, such as chosen heating/cooling equipment, installation costs, or estimated usage. By not placing an EV charger on these second meter rates the risk of charging occurring during peak times is present and considered unmanaged. The EVCR credit aims to support this subset of customers in participating in and shifting EV charging to more economical periods, helping optimize system efficiency and reducing overall costs for all customers. EV owners, who do not currently have a second off-peak service, could see significant savings by not having to install a second meter. Further, by participating in direct

[181] *In the Matter of Otter Tail Power Company's 2023 Integrated Distribution Plan*, *Commission Order*, February 3, 2026, Docket No. E-017/M-23-380, (eDockets) 20262-227791-01 (hereinafter "EV Load Management Order")

> demand control the customer will receive a monthly credit, reducing the overall energy cost of charging their electric vehicle.[182]

In the EV Load Management Rate Petition, the Company stated that through the new rate and bill credit, "the Company can better align EV load with off-peak periods, enhancing grid reliability and operational efficiency."

The Department requests that OTP, in reply comments, provide the expected customer count, expected load shift, expected avoided system costs associated with the proposed EV Load Management Rate.

J.4.3. Forecasting and Medium/Heavy-Duty Adoption

The Company provides three light-duty EV growth scenarios (Low, Medium, and Aggressive) but elected to omit forecasts for the medium- and heavy- duty vehicles, citing low negligible current registrations and minimal expected near-term growth. While the Department acknowledges the nascent state of MHD adoption, it finds that Company's broader forecasting methodology problematic. Specifically, the Company's "Medium" growth scenario relies on a 37 percent year-over-year growth rate derived from statewide Minnesota Department of Transportation (MnDOT) registration data.

The Department cautions that applying a statewide growth metric to the Company's predominantly rural service territory likely overstates near-term adoption. Historical uptake rates and recent academic literature suggest that rural adoption curves lag significantly behind state averages due to unique geographical and infrastructure barriers. For instance, recent studies in similar rural jurisdictions indicate that consumer intent to purchase battery electric vehicles (BEVs) remains as low as 5 percent with total registrations hovering near 0.3 percent of the total vehicle fleet.[183,184] Consequently, the Department views a 37 percent growth rate as highly aggressive given the specific demographic and geographic characteristics of the Company's service territory.

J.5. Approve, Reject or Modify

The Department responds to the following notice topic:

> *Should the Commission approve, modify, or reject Otter Tail Power's TEP?*

The Department will make a final recommendation after reviewing OTP's reply comments.

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[182] *In the Matter of Otter Tail Power Company's 2023 Integrated Distribution Plan,* Otter Tail Power Company, Petition, October 3, 2025, Docket No. E017/M-23-380, (eDockets) 202510-223593-01, at 5.
[183] A survey of 1000 rural Michigan resident found that only 5% of respondents would choose a BEV as their next vehicle. Source: Tomkins, Sabina, Sally Yin, Parth Vaishnav, and Anna Stefanopoulou. "Quantifying real and perceived barriers to EV adoption in rural michigan." *Scientific Reports* (2025).
[184] "In 2024, there were 3.4 electric vehicles per 1,000 registered vehicles in rural Pennsylvania." Rural Transportation Trends: Growth in Electric Vehicle Use, Center for Rural Pennsylvania, December 2025.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of Otter Tail's 2025 IDP and the information in the record, the Department has prepared recommendations, which are provided below. The recommendations correspond to the subheadings of Section III above.

REQUESTS FOR ADDITIONAL INFORMATION DURING REPLY COMMENTS:

C. CAPACITY

- C.1. The Department requests OTP present in reply comments, a summary histogram that plots the number of substation transformers in bins of substation transformer utilization (peak load / rated capacity) sized at 10% bin widths, from 0% to 100%, with an overflow bin of ≥ 100%. OTP should provide a second histogram of substation transformer utilization compared to emergency ratings, if this data is readily accessible. These histograms should exclude substations with either 0 measured load or no data logging capabilities
- C.2. The Department requests OTP explain in reply comments how the Company views capacity overload risks at its substations and the need for capacity mitigations with historic or existing substation transformer overloads. As applicable, OTP should discuss why the Company has no plans to mitigate substation transformer capacity overloads at any substation transformers that have not been identified for upgrades.
- C.3. The Department requests OTP present in reply comments, a feeder utilization histogram that is comparable to the Department's requested substation transformer utilization histogram using OTP's Feeder Data Spreadsheet.
- C.4. The Department requests OTP present in reply comments a cost effectiveness analysis of a 1.5 MVA and 2.0 MVA substation transformer sizing standard compared to its 2.5 MVA standard.

D. RELIABILITY

- D.1. The Department recommends that OTP, in its reply comments, provide a short narrative linking each major reliability-driven program in Appendix B, by MN IDP Category, to specific outage causes, reported in Table 3. The narrative should also quantify, where feasible, the share of each program's Minnesota spend that is directed at each primary cause category.
- D.2. The Department requests that OTP, in reply comments, explain the reasoning behind the significant reduction in the forecasted budget for reliability and power quality upgrades from 2025-2029.
- D.3. The Department requests that OTP, in reply comments, report its reliability metrics outcomes, categorized with workstation and substation, from the reliability and power quality

investments made from 2020-2024. These metrics should include actual SAIDI, SAIFI, CAIDI, and customer minutes of outage (CMO), where applicable.

- D.4. The Department requests that OTP, in reply comments, explain the reasoning behind classifying OH-to-UG conversion projects to two MN IDP Categories (PQ & Reliability Upgrades and Age Related/Asset Renewal) in Appendix B.
- D.5. The Department requests that OTP, in reply comments, provide a short summary table for all Minnesota strategic OH-to-UG project planned or completed during 2025-2029. This table should specify which criteria (safety, customer impacted, outage history, restoration access, vegetation-management access, backlot vs. front-lot routing) were determinative in selecting that project. Additionally, OTP should identify any feeders that met several criteria but were not selected and explain the reasons for their exclusion.
- D.6. The Department requests that OTP, in reply comments, provide, for at least Fergus Falls and Morris, pre-project and post-project feeder-level SAIDI, SAIDI, and CAIDI values for at least the most recent 12-24 months.
- D.7. The Department requests that OTP, in reply comments, explain why its normalized generic cost estimates show underground taps as less costly than overhead taps, including: 1) what specific cost components (labor, materials, easements, restoration) are included for each case; 2) whether different design assumptions (e.g., conductor size, trenching conditions, service configuration) apply to the tap cases; and 3) whether these values reflect Minnesota specific or system-wide averages.

E. AGE RELATED REPLACEMENTS AND ASSET RENEWAL

- E.1. The Department requests that OTP present, in reply comments, an explanation of how old its four undergrounding projects are, and describe any reasons why each planned project is scheduled to be replaced before or after the 50 year depreciation period. The discussion should include OTP's criteria used to prioritize Underground Asset Replacement projects.
- E.2. The Department requests that OTP present, in reply comments, an explanation of how old its nine substation projects are, and describe any reasons why each planned project is scheduled to be replaced before or after the 45 year depreciation period
- E.3. The Department requests that OTP present, in reply comments, an explanation of why OTP's two substation Consolidation projects and two New Substation projects are necessary compared to replacing the substations like for like.
- E.4. The Department requests that OTP explain, in reply comments, how the Company plans to address the risk of oversized system assets in its planned Age Related Replacements and Asset Renewal projects.

F. WILDFIRE

- F.1. The Department requests that OTP present in its reply comments a breakdown of all fire outages caused by wildfire compared to all fire outages caused by any other means. OTP should outline which specific outages in IR 5 correspond to actual wildfires.

- F.2. The Department requests that OTP un-redact, as appropriate, the Department's trade secret summary of OTP's outage data from IR 5.

H. NON-WIRES ALTERNATIVES ANALYSIS

- H.1. The Department requests that OTP, in reply comments, clarify and describe the types of projects it considers for its NWA analysis.
- H.2. The Department requests that OTP, in reply comments, describe the Company's process for its NWA analysis.

J. TEP

- J.1. The Department requests that OTP, in reply comments, update tables 1 and 2 of its TEP[185] to indicate the number of and expenditures related to level 2 charger rebates provided by the Company in the last five years and the planned rebates for the next five years.
- J.2. The Department requests that OTP discuss, in reply comments, how its Transportation Electrification portfolio addresses the requirement of Minn. Stat. § 216B.1615 subd. 3(5).
- J.3. The Department requests that OTP, in reply comments, explain the range of anticipated future transportation electrification spending depicted in its Table 2.
- J.4. The Department requests that OTP, in reply comments, provide a five-year cost-benefit projection of its DCFC fleet, detailing rural-specific fixed and variable maintenance costs alongside targeted utilization strategies to improve revenue ratios. This analysis must include a clear roadmap toward financial self-sufficiency to protect non-EV-driving ratepayers from long-term O&M subsidies.
- J.5. The Department requests that OTP, in reply comments, provide the expected customer count, expected load shift, expected avoided system costs associated with the proposed EV Load Management Rate.

PRELIMINARY RECOMMENDATIONS:

D. RELIABILITY

[185] 2025 TEP— at 8.

- D.1. The Department recommends the Commission require OTP, in its next IDP, to develop clear reporting metrics for its reliability projects (e.g., miles converted, segments addressed) and provide a clear methodology for selecting segments in its distribution system for reliability and power quality upgrades.
- D.2. The Department recommends the Commission require OTP, in its next IDP, 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.
- D.3. The Department recommends that targeted undergrounding be evaluated alongside other reliability mitigation methods that can materially reduce outage minutes on targeted feeders.

E. AGE RELATED REPLACEMENTS AND ASSET RENEWAL

- E.1. The Department recommends that all of OTP's New Undergrounding projects under its Age Related Replacement Budget undergo the same cost effectiveness analysis as undergrounding projects in the System Expansion or Upgrades for Reliability and Power Quality budget category.
- E.2. The Department recommends that the Commission require OTP to provide a cost benefit analysis of its Cut-Out Replacement Program in OTP's 2027 IDP that weighs the reliability benefits of the program against the deferral benefits of replacing cut-outs at the end of their useful life.

F. WILDFIRE

- F.1 The Department recommends that the Commission require Otter Tail to file its future (outside of the current rate case test year) Minnesota-specific Wildfire Mitigation Plan with the Commission as an attachment or supplement to its IDP. The Department recommends the Commission require OTP to include at least the following in its Wildfire Mitigation Plan:
    - 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).
    - A definition of "wildfire" as it is used for utility identification, planning and mitigation.
    - A discussion of its risk modelling, mapping and project prioritization process within its Wildfire Mitigation Plan.

- Quantification of actual wildfire risk in OTP's territory based on the probability and size of a fire, and land use.
  - Wildfire risk should be compared to other reliability and safety risks as well as the wildfire risk experienced in OTP's other jurisdictions.
- Quantification of wildfire damages by event size, including OTP-owned and other property damage, applicable liability, and any other costs OTP deems reasonable to include.
- 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.
- 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.
- Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the approved wildfire mitigation measures, showing that wildfire-related outages in OTP's territory decreased by 50 percent; the average length of wildfire-related outage decreased by 20 percent.[186]).
- A full cost benefit analysis of any wildfire mitigation proposals.

[186] Values are arbitrary given as examples for how OTP could demonstrate the efficacy of its wildfire mitigation plan.

Attachments

Attachment A – Compliance Table

Otter Tail Power Company’s 2025 Integrated Distribution Plan

Planning Objectives	How does OTP’s IDP meeting the Commissions planning objectives?	3	OTP discusses IDP planning objectives.
3.A.1	Modeling software	4	OTP discusses its Otter Tail Load Management System (LMS).
3.A.2	Percentage of substations and feeders with monitor & control	6	OTP provides substation and feeder statistics.
3.A.3	Summary of M&V and planned improvements	6	OTP has limited visibility of distribution facilities throughout its system on a real-time basis. Only a small number of OTP's distribution substations have control and monitoring within OTP’s System Operations Energy Management System.
3.A.4	Number of customers with AMI/Smart Meters	6	Nearly all of Otter Tail’s billing meters are manually read today.
3.A.5	Discussion of IRP and IDP relationship	7	The baseline forecast for both the IDP and IRP include, or “net,” the effects of DER trends on the system.
3.A.6	Discuss how DERs and electrification is considered in load forecasting	7	OTP discusses timing of system wide impacts in load forecasting.
3.A.7	IEEE 1547-2018 impacts	4.B	OTP does not anticipated updated requirement to have negative effects. Advanced autonomous inverter control settings could benefit OTP.
3.A.8	Distribution system loss percentages	7.D	OTP's minimum feeder or substation loading reports showed a loading of 0 kWs in many cases. Therefore, Appendix A shows the minimum “non-zero” loading level between daytime hours.
3.A.9	Coincident load at distribution interface	Appendix A	Without demand meters, OTP is unable to know the total loading and use engineering assumptions.
3.A.10	Substation capacity	6	OTP provides this information in Table 5.
3.A.11	See 3.10 – same answer	6	OTP provides this information in Table 5.

3.A.12	Total Miles OH	6	OTP provides this information in Table 6.
3.A.13	Total miles of UG	6	OTP provides this information in Table 6.
3.A.14	Total number of distribution customers	6	OTP provides this information in Table 7.
3.A.15	Costs spent on DER gen installations	4.B	OTP does not keep detailed records to track the cost to review/install a DER.
3.A.16	Total charges to customers for DER	4.B	OTP does not keep detailed records to track the cost to review/install a DER.
3.A.17	DER nameplate gen installations	4.B	OTP provides nameplate gen installs.
3.A.18	DER count installations	4.B	OTP provides count installs.
3.A.19	Existing DER	4.B	OTP provides existing DER.
3.A.20	Queued DER	4.B	OTP provides queued DER.
3.A.21	EVs in Minnesota	7	OTP provides data on EV in service area.
3.A.22	Number and capacity of EV chargers	7	OTP discusses EV charging number.
3.A.23	Units of battery storage	10	OTP has no electric storage on its system.
3.A.24	Savings and demand savings from EE	9.C	Current master control system is old, not vendor supported and has limits. Replacement is planned. OTP has automated metering infrastructure project and update for load management system.
3.A.25	Amount of Controllable Demand	9.C	Current master control system is old, not vendor supported and has limits. Replacement is planned. OTP has automated metering infrastructure project and update for load management system.
Financial Information			
3.A.26	Historical spending in new categories	8	OTP provides historical spending data.
3.A.27	Historical spending in OTP categories	8	OTP provides investment information.

3.A.28	Investments on the system not by OTP	8	OTP provides projected spending data.
3.A.29	Projected spending 5 years into the future	8/Appendix	OTP provides projected capital project spending.
3.A.30	Non-Wires alternatives CBA	10	OTP does not have cost-bene analysis per se but describes planned projects.
DER Deployment			
3.A.31		4.B	OTP provides information on DER deployment/geographical dispersion.
3.A.32		4.B	OTP provides information on areas of high DER penetration.
3.A.33		4.B	OTP provides information on where advanced inverters are needed.
3.A.35		9.C	OTP provides information on system upgrades for EV charging.
3A.36		9.C	OTP provides general information.
Preliminary Hosting Capacity Data			
3.B.1		Appendix A	OTP provides this information in Appendix A.
DER Scenario Discussion			
3.C.1		7	OTP provides this information.
3.C.2		7	OTP provides this information.
3.C.3		7	OTP provides this information.
3.C.4		12	OTP provides this information.
Long-Term Distribution Grid Mod Plan			
3.D.1		4, 7, 8, 9	OTP provides development plan for distribution system.
3.D.2		4, 7, 8, 9	OTP provides development plan for distribution system.
Non-Wire Alternatives			
3.E.1		10	OTP provides discussion on distribution system projects.
3.E.2		10	OTP provides discussion on distribution system projects.

Transportation Electrification Plan			
3.F		7	OTP discusses its TEP plans.
9/9/20 Order in Docket M-19-693		8, 9	OTP discusses its financial information and methodologies used in its 2030 Initiative plans.
9/9/22 Order in Docket M-21-612		8, 9	OTP discusses the status of its 2030 Initiative.
9/12/23 Order in Docket CI-22-624		4, 7	OTP discusses issues associated with the IRA as it relates to EV projects and solar panels.
9/12/24 Order in Docket M-23-380		10	OTP provides discussion on non-wires alternative analysis.
9/12/24 Order in Docket M-23-380		10	OTP provides discussion on Morris project.
9/12/24 Order in Docket M-23-380		7	OTP provides discussion project.
9/12/24 Order in Docket M-23-380		4, 5, 7, 8, 9, Appendix A	OTP provides discussion. With respect to providing detailed demographic data, OTP states that its DER deployment is not high enough to warrant detailed data collection regarding income/race.
2023 Minn. Laws Ch. 60, Art. 12, Sec. 12, Minn. Stat. 216B.1615		7	OTP discusses plan.
12/8/22 Order in Dockets CI-17-879, M-21-612		7	OTP discusses plan.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz
Date Received: November 26, 2025
Date Due: December 22, 2025
Date of Response: December 22, 2025
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please provide a list the following data for 2023 and 2024:
A. Each outage event on the distribution system
B. Location of the outage
C. Cause of the outage
D. Estimated customer minutes of outages experienced

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Attachments: 1

Attachment 1 to MN-DOC-005-PUBLIC.pdf

Response:
Attachment 1 to IR MN-DOC-005 information contains historical and/or projected information on individual customers (the "Protected Data"). The Protected Data is nonpublic data pursuant to Minn. Stat. § 13.02, subd. 9 due to the Commission's January 19, 2017 Order in Docket No. E,G999/CI-12-1344, which requires Otter Tail Power to refrain from disclosing this data without the customers' consent. As nonpublic data, the Protected Data also constitutes not public data, as defined in Minn. Stat. § 13.02, subd. 8a and is protected data under Minn. R. 7829.0100, subp. 19a(A).

Please see Attachment 1 in response to Information Request MN-DOC-005 for the Informational details such as location, cause, customer minutes, date and time, and number of customers impacted are specified.

Total Minnesota distribution only, non-normalized, outages in 2023 and 2024 equals 2,686 events.

2023: 1,434 outage event records
2024: 1,252 outage event records

Additional summary information is as follows below:

CSC	2023 MN Dist. Outage Count
Bemidji	235
Crookston	243
Fergus Falls	643
Morris	313
2023 Total	1434

CSC	2024 MN Dist. Outage Count
Bemidji	278
Crookston	143
Fergus Falls	589
Morris	242
2024 Total	1252

2023 – MN Distribution Outages by Cause

Cause	Outage Count
Material or equipment failure	303
Squirrel	213
Maintenance	203
Weather	201
Tree on the line	156
Cause unknown	143
Public	120
Animal caused, not squirrel	51
Equipment fault or operation	24
Fire	10
Downstream customer issue	10
2023 Total	1434

2024 – MN Distribution Outages by Cause

Cause	Outage Count
Maintenance	220
Material or equipment failure	217
Squirrel	177
Tree on the line	167
Cause unknown	156
Weather	129
Public	108
Animal caused, not squirrel	35
Fire	19
Downstream customer issue	14
Equipment fault or operation	10
2024 Total	1252

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Information Request:
Please provide the actual 2018-2024 energy sales to OTP's Minnesota retail customers that are served at the distribution level or at a cost of service that is tied to distribution charges. To elaborate on the cost of service component, please include sales to any transmission-level customers whose rates include distribution cost allocation.

Attachments: 1

Attachment 1 to IR MN-DOC-006.xlsx

Response:

Please see Attachment 1 to IR MN-DOC-006 for 2018-2024 energy sales to OTP's Minnesota retail customers that are served at a cost of service that is tied to distribution charges. These energy sales are based on kWh sales adjusted for line losses to the generation level. There are no transmission-level customers whose rates include distribution cost allocation.

It should be noted that this information coupled with OTP’s distribution spend alone should not be used to determine rate impacts. As stated in the 2025 MN IDP, there are only a handful of projects in the IDP that are not covered by existing rates.

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Date of Response: December 22, 2025
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please provide the following information for each substation and feeder line operated by OTP:

A. Rated Capacity
B. Technical Planning Standard Capacity that triggers a need for a capacity upgrade
C. 3-year highest peak load observed

For any system assets that do not have the available data, please summarize the number of assets by type [substation / feeder] that are affected and explain why the data is not available.

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Attachments: 1

Attachment 1 to IR MN-DOC-008.xlsx

Response:

A. Substation Data only provided. See Attachment 1 to IR MN-DOC-008.xlsx.
   It should be noted the substation kVA is the rated capacity of the substation transformer. There may be other equipment or technical reasons (i.e. voltage support) that could limit the total substation load capacity.
B. There is not a simplified way to determine each substation's planning capacity. OTP Distribution Engineering does a specific study on the substation and feeder for each new load or DER addition, to determine if existing system capacity is adequate. One approximation that is discussed in OTP's MN IDP is minimum loading. This is discussed in OTP's MN IDP under section 7.D and attachment A.
C. 3-year highest peak load observed is not available.
   a. OTP does not currently have the capability to provide accurate 3-year highest peak load observed at MN substations due to our AMI substation meter upgrades, data integration development and data historian status.
   b. OTP has 333 feeders in Minnesota which do not have load data measurement equipment installed.

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Date Due: December 22, 2025
Date of Response: December 22, 2025
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please provide:
A. Actual expenditures for OTP's O&M separated by the internal O&M budget categories for the years 2018 through 2024.
B. Forecasted expenditures for OTP's internal O&M budget categories for the years 2025 and 2026.
C. Actual capital expenditures by OTP's internal budget categories for years 2018 through 2024.
D. Forecasted capital expenditures by OTP's internal budget categories for years 2025 through 2029.

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Attachments: 0

Otter Tail tracks expenses through required FERC account codes. Below in Table 1 are the historical amounts for operations and maintenance accounts for the years 2018 through 2024 as requested under part A. Below in Table 2 is the historical capital spend in the same FERC categories for the years 2018 through 2024 as requested under part C.

A. Table 1 – Historical O&M Amounts

	O&M Type	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24
Operating	Generation - Other Power Gen	3,854,138	3,871,612	4,192,213	5,117,473	6,812,562	9,160,739	9,776,666
	Generation - Steam	17,080,920	15,146,691	15,078,754	12,967,858	13,585,138	11,732,169	13,353,322
	Generation - Hydraulic	84,997	70,876	55,365	40,694	96,000	40,986	57,678
	Transmission	25,052,854	26,974,047	24,483,537	27,642,209	31,754,509	30,005,134	29,548,516
	Distribution	8,009,283	8,523,043	7,977,264	8,458,598	7,760,822	8,430,641	9,128,891
	Generation - Other Power Sup	379,690	378,865	430,877	468,979	473,797	481,755	491,827
	Regional Market Expenses	819,272	726,369	842,233	886,487	800,367	771,502	899,507
40 Operating Total		**55,281,153**	**55,691,502**	**53,060,243**	**55,582,298**	**61,283,196**	**60,622,926**	**63,256,409**
Maintenance	Generation - Other Power Gen	828,204	627,407	755,524	4,519,368	5,232,759	6,137,965	6,033,831
	Generation - Steam	14,202,252	14,576,578	8,593,200	11,538,396	12,208,951	9,683,485	8,821,022
	Generation - Hydraulic	237,599	261,812	259,338	258,944	311,282	274,404	325,223
	Transmission	4,356,282	3,403,964	3,779,565	3,681,188	4,688,100	5,761,801	5,757,035
	Distribution	10,258,546	9,806,551	9,093,190	8,664,477	9,542,873	11,705,400	10,190,695
	Regional Market Expenses	280,206	239,647	257,038	229,437	247,043	246,956	247,475
50 Maintenance Total		**30,163,089**	**28,915,959**	**22,737,855**	**28,891,810**	**32,231,008**	**33,810,011**	**31,375,280**
		85,444,241	**84,607,462**	**75,798,098**	**84,474,109**	**93,514,203**	**94,432,937**	**94,631,689**

Table 2 – Historical Capital Expenditure Amounts

Activity	Activity Description	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24
0290	Construct Dist Facilities	11,610,649	9,229,359	15,817,210	21,644,551	25,156,335	36,242,400	43,970,543
0360	Construct Generating Plant	17,711,160	144,326,451	149,559,483	21,561,265	47,176,321	37,974,297	130,392,446
0920	Market Research		-6,583					
1140	Construct General Plant	2,230,935	2,316,668	5,708,022	5,691,886	7,957,840	14,193,736	13,768,382
1145	Purchase Intangible Plant	17,560,355	0	2,846,324	975,440	8,197,744	8,884,195	212,644
1510	Construct Trans Facilities	121,501,298	21,972,846	32,277,952	26,867,359	29,886,471	49,377,366	47,647,182
Grand Total		**170,614,396**	**177,838,740**	**206,208,991**	**76,740,501**	**118,374,711**	**146,671,993**	**235,991,197**

Table 3 below shows the 2025 and 2026 forecasted O&M amounts as requested under part B of the IR

Table 3 – 2025 and 2026 Forecasted O&M Amounts

	2025	2026
Steam Power Generation	$ 23,705,285	$ 27,722,213
Hydraulic Power Generation	331,163	444,301
Other Power Generation	8,980,582	19,522,547
Wind Production	5,977,799	-
Solar Production	289,789	-
Other Power Supply	533,509	553,788
Total Power Production	**$ 39,818,128**	**$ 48,242,848**
Transmission	$ 13,306,515	$ 16,693,114
Regional Market Expenses	1,099,787	1,261,808
Distribution	17,787,162	25,362,851
Energy Storage	40,864	-
Customer Accounts	11,081,289	10,251,315
Customer Service	2,577,021	3,545,644
Sales	448,992	542,611
Administrative & General	59,064,904	63,590,521
Total O&M	**$ 105,406,534**	**$ 121,247,864**

Table 4 below shows the forecasted distribution capital spend as presented in the IDP as it pertains to part D of this IR.

Table 4 – Forecasted 5-year Distribution Spend for Minnesota (with WMP)

Category[1]	**2025**	**2026**	**2027**	**2028**	**2029**
Age Related Replacements and Asset Renewal	$13,566,296	$19,652,727	$16,184,098	$17,578,333	$17,862,500
System Expansion or Upgrades for Capacity	$1,600,000	$2,015,000	$3,050,000	$2,250,000	$770,000
System Expansion or Upgrades for Reliability and PQ	$1,557,548	$1,350,924	$1,530,000	$1,017,500	$845,000
New Customer Projects and New Revenue	$5,632,000	$5,450,000	$6,415,000	$6,235,000	$5,960,000
Grid Modernization and Pilot Projects	$12,341,857	$14,232,929	$7,149,068	$5,025,092	$1,744,167
Projects Related to local(or other) Government Requirements	$137,500	$142,500	$147,500	$152,500	$157,500
Metering	$250,000	$500,000	$625,000	$643,750	$663,063
Other	$401,750	$812,500	$912,500	$762,500	$237,500
Electric Vehicle Programs (See TEP-Table 14)					
Grand Total	**$35,486,951**	**$44,156,581**	**$36,013,167**	**$33,664,676**	**$28,239,730**

[1] All costs specific to Minnesota. When system wide costs were not broken down by state or a part of larger programs (i.e. metering) a 50 percent allocator was applied to represent Minnesota only costs. Fifty percent is used because approximately half of company energy and demand use resides within Minnesota.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 25, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
OTP lists several Asset Health programs. For each listed Asset Health Program, please describe, as applicable:

1. The 5-year budget
2. Whether OTP has an inspection program a. If so, please present data on failure rates by age
3. Whether OTP conducts any analysis on the cost effectiveness of the program a. If so, explain what measures OTP uses and how these measures determine the value of the program
4. Whether OTP analyzes benefits of any individual projects under the program.

Attachments: 0

Response:

1. See Appendix B of OTP 2025-2027 MN IDP for the various projects and programs in the 5-year budget. Program names within Appendix B follow those described in the Asset Health section of the report.
2. OTP completes annual distribution substation inspections. These inspections are used to evaluate substation condition and prevent larger reliability issues. OTP has historically completed opportunistic distribution inspections of the distribution system beyond the fence of the substation. OTP has recently instituted a new Advanced Distribution Line Inspection Program that is discussed in OTPs rate case in addition to continuing opportunistic inspections.
    a. OTP does not have failure rates by age
3. Inspection programs have not historically been evaluated for cost effectiveness. Inspection processes are considered utility best practices.
4. See similar response to 3 above for inspection programs.

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Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 19, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
For OTP's Strategic Undergrounding Program, please describe:
1. Whether OTP estimates the reduction in customer minutes of outage for the program, and for individual projects
2. How OTP determines that a strategic undergrounding project is net cost beneficial to ratepayers

Attachments: 0

Response:

1. OTP does not perform a standalone cost-benefit or predictive analysis specific to each overhead-to-underground (OH-to-UG) conversion project. However, OTP maintains and reviews historical feeder performance data for circuits where OH-to-UG projects have been completed. This historical data clearly demonstrates substantial improvements in reliability metrics following project completion, including significant reductions in outage frequency and duration. These post-project performance gains provide strong empirical evidence that OH-to-UG conversions materially improve system reliability and customer service outcomes.
2. Proactive replacement of aging overhead distribution facilities with underground infrastructure materially reduces exposure to weather-related outages and improves overall system resiliency. From a long-term planning perspective, OH-to-UG conversions can be considered cost-effective due to avoided operations and maintenance expenses, including reduced emergency restoration activity, overtime labor, contractor support, and travel costs associated with storm response and unplanned outages. In addition, underground facilities eliminate the need for ongoing rotational vegetation management along overhead corridors, resulting in reduced tree-trimming expenditures over the life of the asset. These projects also reduce the potential for property damage and customer disruption associated with emergency access by utility vehicles and equipment. Collectively, these benefits support OTP's distribution system planning objectives related to reliability, safety, and prudent cost management. Additional information regarding the OH-to-UG program, including planning criteria and prioritization considerations, is provided in Section 9.F of the IDP.

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Date Due: February 26, 2026
Date of Response: February 25, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please provide generic, per-mile cost estimates to install a new build typical section of overhead and underground feeders and tap lines.

Attachments: 0

Response:

The below table shows "generic estimates" for a new build typical one mile section of overhead (OH) and underground (UG) feeders and tap lines. Costs have been normalized relative to 1 mile of single phase overhead tap construction.

Type	Phase	Relative Cost/Mi
Overhead Tap	1	1.00
Overhead Feeder Low End	3	1.33
Overhead Feeder High End	3	1.50
Underground Tap	1	0.79
Underground Feeder Low End	3	1.69
Underground Feeder High End	3	4.60*

*High end range represents directional boring of very large underground cable which drives up costs

For actual projects, a Work Order estimate is created through our design system software for each project so all the construction unit and project specific variables associated are accounted for.

Lastly, it should be noted that UG distribution provides lifecycle benefits in reliability, resilience, safety, maintenance, and risk reduction that are not fully captured by upfront capital cost comparisons. While OH distribution remains appropriate in many applications, particularly in low-density or lower-risk areas, UG distribution can offer long-term value when deployed in locations where reliability, safety, environmental exposure, and system resilience are key considerations.

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Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 25, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
OTP states:
It should be noted that design standards create system capacity "step changes." For example, underground feeder design standards are rated at either 200 or 600 ampacity, or substation transformer sizing which is standardized to future purchases of 1 MVA or 2.5 MVA. This helps maintain efficient installation, and stock inventory of replacement asset materials. In doing so, building of the distribution system can appear "overbuilt" in terms of capacity. However, the system was not overbuilt at all but rather efficiently planned, designed and constructed to handle future growth.

Please provide:
1. A summary of each relevant capacity design standard for substation transformers, overhead feeders, underground feeders, overhead tap lines, underground tap lines, and any other relevant equipment.
2. An estimate of the difference in cost to install equipment described in 1. if the capacity exceeds the lower design standard by 10 percent, and the new equipment is rated at half of the next design standard capacity.

Attachments: 0

Response:

OTP distribution construction is guided by its internally developed and maintained, Material and Construction Standards book. This book contains thousands of pages outlining design standards that have been developed over many years. Summarizing that document is not feasible. Instead, OTP provides an example of how total construction costs are impacted by a move from one standard material to another; reflecting a step change in ampacity.

Table below illustrates medium voltage (MV) underground (UG) Cable Industry sizes as well as OTP Standard sizes (highlighted in blue) along with Ampacity, purchase price, and installation costs. All costs are normalized relative to OTP Standard 1/0 MV UG cable. Total installed costs are shown in high and low end ranges on the far right four columns. Again, these are normalized relative to the material costs of the OTP 1/0 MV cable.

Industry Standard MV Cable Sizes	Ampacity	DeadBreak Connections Ampacity	Relative Ampacity	Purchase Price $/ft (Relative)	Install Cost low (1 Ph Primary - Lateral) $/FT	Install Cost low (3 Ph Primary - Feeder) $/FT	Install Cost High (Boring 1 Ph Primary Lateral) $/FT	Install Cost High (Boring 3 Ph Primary Feeder) $/FT	Relative Installed Total $/FT Low Lateral	Relative Installed Total $/FT High Lateral	Relative Installed Total $/FT Low Feeder	Relative Installed Total $/FT High Feeder
2 sol	168	200	0.77	0.82	0.75	1	3	5	0.90	2.18	N/A	N/A
2 str	168	200	0.77	0.84	0.75	1	3	5	0.91	2.19	N/A	N/A
1 sol	193	200	0.89	0.9	0.75	1	3	5	0.94	2.23	N/A	N/A
1 str	193	200	0.89	0.93	0.75	1	3	5	0.96	2.25	N/A	N/A
1/0 sol	218	200	1.00	1	0.75	1	3	5	1.00	2.29	2.29	4.57
1/0 str	218	200	1.00	1.03	0.75	1	3	5	1.02	2.30	2.34	4.62
2/0 str	248	200	1.14	1.18	0.75	1	3	5	1.10	2.39	2.59	4.88
3/0 str	284	200	1.30	1.23	0.75	1	3	5	1.13	2.42	2.68	4.97
4/0 str	324	600	1.49	1.33	0.75	1	3	5	1.19	2.47	2.85	5.14
250 str	360	600	1.65	1.36	0.75	1	3	5	1.21	2.49	2.90	5.19
350 str	389	600	1.78	1.4	0.75	1	3	5	1.23	2.51	2.97	5.26
500 str	468	600	2.15	1.46	N/A	1.2	N/A	5	N/A	N/A	3.19	5.36
750 str	569	600	2.61	1.63	N/A	1.2	N/A	5	N/A	N/A	3.48	5.65
1000 str	642	600	2.94	1.67	N/A	1.2	N/A	5	N/A	N/A	3.55	5.72
1250 str	688	600	3.16	1.78	N/A	1.2	N/A	5	N/A	N/A	3.74	5.91
1500 str	726	600	3.33	1.82	N/A	1.2	N/A	5	N/A	N/A	3.81	5.98

*OTP Standard MV UG Cable Sizes
*Ampacity limited by Connections
*Connection Ampacity not fully utilized
*Base unit for caculation of costs

In summary, if 1/0 sol cable capacity is exceeded by 10%, necessitating an increase step to next standard cable size of 4/0, installed cost increases to range of 1.19-2.47 for laterals and 2.85-5.14 for feeders.

Similarly, if 1/0 sol capacity is exceeded by 10% and an additional standard of 2/0 was added, total installed cost increase to a range of 1.10-2.39 for laterals and 2.59-4.88 for feeders.

By having a step change from 1/0 to 4/0 instead of 1/0 to 2/0 (non-OTP standard), corresponds to a 3-8% installed cost adder for laterals and a 5-10% cost adder for feeders. However, ampacity changes from a 200 amp limitation to 600 amp limitation. The other benefits of maintaining standards are discussed in the IDP in Section 4.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 18, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please describe:

1. The planning standard or standards that OTP uses to determine if a capacity upgrade is needed for feeders, tap lines, transformers, or other equipment.
2. How OTP coordinates capacity upgrades with projects identified for reliability and/or age-related replacements.
3. How OTP coordinates 2. with storm-related asset replacements.

Attachments: 0

Response:

1. Otter Tail Power begins planning for system upgrades once a facility has been identified as exceeding 90% of its' thermal rating near peak demand through telemetry data or through planning studies. However, some equipment, such as transformers for example, can handle short-duration thermal overloads better than other facilities can. Therefore, in certain circumstances, OTP does allow transformers to exceed their thermal rating, as long as it's for short durations, before requiring a transformer upgrade. This can be necessary given the long-lead times and difficulties in procuring new transformers. It should be noted that with AMI data, the granularity in which this analysis can be completed will be much greater than historical. OTP is anxious to start using the demand information from the newly installed AMI system.

2. OTP Engineers follow our construction standards regarding capacity when designing construction WO's. To determine capacity needs on projects, distribution design engineers will coordinate with our distribution studies team to understand various loading levels throughout the distribution system. This helps guide what construction standards to follow.

3. Storm related replacements follow the same construction standards regarding capacity as discussed in item #2. During storm restoration, there is no time for engineering loading studies so at a minimum, like for like capacity materials are used.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 18, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please explain if OTP includes the risk of contingency events (N-1) in its capacity planning standards.

- If OTP does include N-1 capacity planning, please explain how the probability of these events is accounted for within OTP's planning standards.

Attachments: 0

Response:

Otter Tail Power strives to provide redundancy for our customers to increase both customer satisfaction and system reliability. Therefore, in cases where redundancy on the distribution system is feasible or exists already, OTP does include N-1 contingency events in our distribution planning standards. The probability of the N-1 events occurring has not been historically considered, which is consistent with transmission planning standards as well.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 23, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
When OTP needs to replace a system asset, please describe:

1. How many forecasted years OTP will consider in its analysis. a. If the forecast varies by project or asset type, please provide a summary of how the forecast varies in different scenarios.
2. What data OTP includes in its analysis of the need for asset replacement.
3. How forecast uncertainty is accounted for in OTP's asset replacement methodology.

Attachments: 0

Response:

Otter Tail uses many different data sources when determining if an asset(s) on the system needs replacement. Some of these data sources include historical reliability information, inspection reports, and asset vintage data. Further discussion on OTPs asset health & age-related programs are listed in the IDP under section 9.F.

For the distribution system, the following table shows some of the depreciation values that Otter Tail uses in its financials. Note these are financial depreciation values and not necessarily what the expected life might be for an asset in the field.

Asset Type	Average Service Life
Distribution Poles	364 Poles, Towers & Fixtures – 72 Years
Distribution Insulators	365 Overhead Conductor & Devices – 68 Years
Pad mount Transformers	368 Line Transformers – 45 Years
Pole mount Transformers	368 Line Transformers – 45 Years
Underground Cable	367 Underground Conductor – 50 Years

To account for forecast uncertainty, or the risk of assets failing before they are scheduled for replacement is handled through general budgets. In Appendix B, there is a line item in each of the 5-year forecasts for General Distribution Replace. Many break/fix type projects are completed under this budget. In addition, contingency amounts within budgets account for uncertainty.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 20, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Please explain how OTP quantifies the value of reliability. The response should:

1. Describe if OTP uses a monetized value of customer minutes of outages (CMO) to compare to costs, or some other metric. a. If OTP uses a monetized CMO value, please outline how the value of different customer classes (i.e. residential vs commercial & industrial) factors into the quantification of value of individual projects. The response should include a breakdown of how the CMO value varies between classes.
2. Include a representative example how of the value of reliability is quantified.
3. Describe how the value of reliability is integrated into OTP's existing decision making processes.

Attachments: 0

Response:

Otter Tail has not yet measured the value of reliability. When selecting projects for upcoming budgets, a review of historical reliability data is a major factor. Circuits or parts of the system that have performed poorly in terms of reliability are given higher priority for improvements. Section 9.F of the IDP report covers additional project planning criteria besides reliability.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Krystal Binversie
Date Received: January 15, 2026
Date Due: February 26, 2026
Date of Response: February 19, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
On Pages 11-13, OTP describes its planning study process. Please explain:
1. How OTP determines the need for a targeted distribution planning study.
2. What planning processes provide data on the need for a targeted distribution planning study.

Attachments: 0

Response:

1. Historically, OTP would determine the need for a targeted distribution planning study in one of two ways:

    a. When notified of a planned expansion or load addition, the Area Engineer would inform OTP's Distribution Studies Engineer to conduct a targeted planning study to identify any system deficiencies related to the new load.
    b. The Distribution Studies Engineer reviews our historical studies to identify towns or systems not studied in over three years, then conducts targeted assessments to gauge current system health. This may also be prompted by issues noted in OTP's internal Feeder Data Spreadsheet, discussed further in response to question #2.

2. Following the completion of our Advanced Metering Infrastructure (AMI) meter rollout, OTP plans to utilize the interruption, reliability, and demand data from our AMI fleet to identify distribution systems that need a planning study in a more proactive manner.

    - Feeder Data Spreadsheet: OTP tracks substation and feeder loading percentages and power factors annually. This helps identify areas with poor power factors or load/DER growth nearing capacity, which then triggers targeted distribution planning studies.
    - Annual Load-Flow Analyses: Each summer, the Delivery Planning department conducts general load-flow analyses. These analyses, along with input from local Area Engineers and trends from the Feeder Data Spreadsheet, help pinpoint areas needing more in-depth study.
    - Advanced Metering Infrastructure (AMI): Once the AMI rollout is complete, OTP will use detailed customer-level telemetry from advanced meters to enhance future planning studies (e.g., 5-10 year forecasts). This will allow more precise, proactive identification of system issues, supporting better decision-making and improving reliability and customer satisfaction.

OTTER TAIL POWER COMPANY
Docket No: E017-M-25-141

Response to: MN Department of Commerce
Analyst: Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz
Date Received: February 19, 2026
Date Due: March 02, 2026
Date of Response: March 02, 2026
Responding Witness: Mike Riewer, Manager, System Infrastructure & Reliability (218) 739-8565

Information Request:
Provide total forecasted energy sales figures for the years 2025 – 2030, in a format that allows for the data to be readily compared to the actual energy sales figures (for the years 2018 – 2024), which were provided in OTP's response to IR No. 6. Please provide these forecasted figures as public data.

Attachments: 1
Attachment 1 to IR MN-DOC-037.xlsx

Response:

Please see Attachment 1 to IR MN-DOC-037 for 2025-2030 energy sales forecast to OTP's Minnesota retail customers (not System sales as provided in IR MN-DOC-007) that are served at a cost of service that is tied to distribution charges. These energy sales are based on kWh sales adjusted for line losses to the generation level. There are no transmission-level customers whose rates include distribution cost allocation.

Year	MN E2 without Transmission Customers
2025	1,827,458
2026	1,845,961
2027	1,849,722
2028	1,852,805
2029	1,854,072
2030	1,854,852

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of people by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E017/M-25-141

Dated this **7th** day of **April 2026**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Daniel	Abelson	daniel.abelson@metc.state.mn.us	Metropolitan Council		390 Robert Street N. St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
2	Brian	Allen	brian.allen@allenergysolar.com	All Energy Solar, Inc		1642 Carroll Ave Saint Paul MN, 55104 United States	Electronic Service		No	M-25-141
3	Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar		721 W 26th st Suite 211 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-141
4	Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences		1954 Buford Ave Saint Paul MN, 55108 United States	Electronic Service		No	M-25-141
5	Janet	Anderson	jcainstp@icloud.com	-		1799 Sargent St. Paul MN, 55105 United States	Electronic Service		No	M-25-141
6	Jay	Anderson	jaya@cmpas.org	CMPAS		7550 Corporate Way Suite 100 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-141
7	MK	Anderson	anderson@fresh-energy.org	Fresh Energy		408 St Peter Street Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141
8	David	Assaf	daassaf@flaherty-hood.com	Flaherty & Hood, P.A.		525 Park Street Suite 470 St. Paul MN, 55102 United States	Electronic Service		No	M-25-141
9	Donna	Attanasio	dattanasio@gwu.edu	George Washington University		2000 H Street NW Washington DC, 20052 United States	Electronic Service		No	M-25-141
10	John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance		1313 5th St SE Ste 303 Minneapolis MN, 55414 United States	Electronic Service		No	M-25-141
11	Anjali	Bains	bains@fresh-energy.org	Fresh Energy		408 Saint Peter Ste 220 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141
12	Mark	Bakk	mbakk@lcp.coop	Lake Country Power		26039 Bear Ridge Drive Cohasset MN, 55721 United States	Electronic Service		No	M-25-141
13	Jared	Ballew	jared.ballew@ev.energy	EV.ENERGY CORP		726 18th St. Des Moines IA, 50314 United States	Electronic Service		No	M-25-141
14	Shay	Banton	shayb@irecusa.org	Interstate Renewable Energy Council		600 H Street NE Apt. 341 Washington DC, 20002 United States	Electronic Service		No	M-25-141
15	Laura	Beaton	beaton@smwlaw.com	Shute, Mihaly & Weinberger LLP		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
16	Mathias	Bell	mathias@weavegrid.com	WeaveGrid		375 Alabama Street, Suite 325 San Francisco CA, 94110 United States	Electronic Service		No	M-25-141
17	Jeff	Benson	jbenson@southcentralelectric.com	South Central Electric Association		PO Box 150 71176 Tiell Drive St. James MN, 56081 United States	Electronic Service		No	M-25-141
18	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-141
19	Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-141
20	Barb	Bischoff	barb.bischoff@nngco.com	Northern Natural Gas Co.		CORP HQ, 714 1111 So. 103rd Street Omaha NE, 68124-1000 United States	Electronic Service		No	M-25-141
21	Ingrid	Bjorklund	ibjorklund@avisenlegal.com	Avisen Legal		901 S. Marquette Ave. #1675 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
22	Ingrid	Bjorklund	ingrid@bjorklundlaw.com	Bjorklund Law, PLLC		855 Village Center Drive #256 North Oaks MN, 55127 United States	Electronic Service		No	M-25-141
23	William	Black	bblack@mmua.org	MMUA		Suite 200 3131 Fernbrook Lane North Plymouth MN, 55447 United States	Electronic Service		No	M-25-141
24	Kenneth	Bradley	kbradley@environmentminnesota.org			2837 Emerson Ave S Apt CW112 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-141
25	Jon	Brekke	jbrekke@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-141
26	Kathleen	Brennan	kbrennan@spencerfane.com	Spencer Fane LLP		100 South Fifth Street, Suite 2500 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
27	Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric		2411 W. Bridge St PO Box 485 Owatonna MN, 55060-0485 United States	Electronic Service		No	M-25-141
28	Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company		215 South Cascade Street	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						PO Box 496 Fergus Falls MN, 56538-0496 United States				
29	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
30	Ed	Brolin	ed.brolin@rwe.com	RWE Clean Energy		100 Summit Lake Drive Suite 210 Valhalla NY, 10595 United States	Electronic Service		No	M-25-141
31	Christopher	Browning	christopher.browning@nexteraenergy.com			null null, null United States	Electronic Service		No	M-25-141
32	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	M-25-141
33	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-141
34	Jerry	Byer	jbyer@itasca-mantrap.com	Itasca-Mantrap Electric Cooperative		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	M-25-141
35	Jennifer	Cady	jjcady@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-141
36	Daniel T	Carlisle	todd-wad@toddwadena.coop	Todd-Wadena Electric Cooperative		550 Ash Ave NE PO Box 431 Wadena MN, 56482 United States	Electronic Service		No	M-25-141
37	Douglas M.	Carnival	dcarnival@carnivalberns.com	McGrann Shea Carnival Straughn & Lamb		800 Nicollet Mall Ste 2600 Minneapolis MN, 55402-7035 United States	Electronic Service		No	M-25-141
38	Pat	Carruth	pat@mnvalleyrec.com	Minnesota Valley Coop. Light & Power Assn.		501 S 1st St. PO Box 248 Montevideo MN, 56265 United States	Electronic Service		No	M-25-141
39	Gabriel	Chan	gabechan@umn.edu			130 Hubert H. Humphrey Center 301 19th Ave S Minneapolis MN, 55455 United States	Electronic Service		No	M-25-141
40	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	M-25-141
41	Eric	Clement	eclement@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-141
42	City	Clerk	gregg.engdahl@ci.stcloud.mn.us	City of St. Cloud		400 Second St. S	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						St. Cloud MN, 56301 United States				
43	Joshua	Cohen	josh.cohen@swtchenergy.com	SWTCH Energy, Inc.		Greentown Labs 444 Somerville Avenue Somerville MA, 02143 United States	Electronic Service		No	M-25-141
44	Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC		26 Winton Road Meredith NH, 32535413 United States	Electronic Service		No	M-25-141
45	Steve	Coleman	stevecolemanpuma@gmail.com			231 Winifred St W Saint Paul MN, 55107 United States	Electronic Service		No	M-25-141
46	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-141
47	Kevin	Cray	kevin@communitysolaraccess.org	CCSA		1644 Platte St Denver CO, 80202 United States	Electronic Service		No	M-25-141
48	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	M-25-141
49	Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-141
50	George	Damian	gdamian@cleanenergyeconomymn.org	Clean Energy Economy MN		13713 Washburn Ave S Burnsville MN, 55337 United States	Electronic Service		No	M-25-141
51	Lisa	Daniels	lisadaniels@windustry.org	Windustry		201 Ridgewood Ave Minneapolis MN, 55403 United States	Electronic Service		No	M-25-141
52	James	Darabi	james.darabi@solarfarm.com			2355 Fairview Ave #101 St. Paul MN, 55113 United States	Electronic Service		No	M-25-141
53	Cody	Davis	cdavis@epeconsulting.com	Electric Power Engineers (ELPC/VS)		null null, null United States	Electronic Service		No	M-25-141
54	Danielle	DeMarre	danielle.demarre@allenergysolar.com	All Energy Solar		1264 Energy Lane St Paul MN, 55108 United States	Electronic Service		No	M-25-141
55	Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures		3500 Bloomington Ave. S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-141
56	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
57	Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative		1302 S Union St Rock Rapids IA, 51246 United States	Electronic Service		No	M-25-141
58	Cheryl	Dietrich	cheryl.dietrich@nexteraenergy.com	NextEra Energy Resources, LLC		700 Universe Blvd E1W/JB Juno Beach FL, 33408 United States	Electronic Service		No	M-25-141
59	Diane	Dietz	diane.dietz@state.mn.us		Department of Commerce	Suite 280 85 Seventh Place East St. Paul MN, 55101-2198 United States	Electronic Service		No	M-25-141
60	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
61	Kristin	Dolan	kdolan@meeker.coop	Meeker Cooperative Light & Power Assn		1725 US Hwy 12 E. Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-141
62	Renee	Doyle	guydoyleelectric@gmail.com	Doyle Electric Inc.		PO Box 295 Amboy MN, 56010 United States	Electronic Service		No	M-25-141
63	Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate		75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul MN, 55155 United States	Electronic Service		No	M-25-141
64	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	M-25-141
65	John R.	Dunlop, P.E.	jdunlop@resminn.com	Renewable Energy Services		Suite 300 448 Morgan Ave. S. Minneapolis MN, 55405-2030 United States	Electronic Service		No	M-25-141
66	Hannah	Dunn	hannah.dunn@oakdalemn.gov	City of Oakdale		1584 Hadley Ave N Oakdale MN, 55104 United States	Electronic Service		No	M-25-141
67	Kelly	Dybdahl	kdybdahl@llec.coop	Lyon-Lincoln Electric Cooperative, Inc.		205 W. Hwy. 14 Tyler MN, 56178 United States	Electronic Service		No	M-25-141
68	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-141
69	Dick	Edwards	dedwards@ci.maple-grove.mn.us	City of Maple Grove		12800 Arbor Lakes Parkway P O Box 1180 Maple Grove MN, 55311-6180 United States	Electronic Service		No	M-25-141
70	William	Ehrlich	wehrlich@tesla.com	Tesla, Inc.		3500 Deer Creek Rd Palo Alto CA, 94304 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
71	Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE		28477 N Lake Ave Frontenac MN, 55026-1044 United States	Electronic Service		No	M-25-141
72	Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte		100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul MN, 55155 United States	Electronic Service		No	M-25-141
73	R. Neal	Elliot	rnelliott@aceee.org	American Council for an Energy-Efficient Economy		ACEEE 529 14th St NW Ste 600 Washington DC, 20045 United States	Electronic Service		No	M-25-141
74	Nadav	Enbar	nenbar@epri.com	EPRI		1117 Quince Ave Boulder CO, 80304 United States	Electronic Service		No	M-25-141
75	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	M-25-141
76	Christian	Fenstermacher	christian.fenstermacher@owatonnautilities.com	Owatonna Municipal Public Utilities		PO Box 800 208 S Walnut Ave Owatonna MN, 55060 United States	Electronic Service		No	M-25-141
77	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	M-25-141
78	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	M-25-141
79	Kornbaum	Frank	fkornbaum@mnpower.com			null null, null United States	Electronic Service		No	M-25-141
80	Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	M-25-141
81	David	Freestate	dfreestate@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-141
82	Katelyn	Frye	kfrye@mnpower.com	Minnesota Power		30 W Superiot St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-141
83	Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-141
84	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
85	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-141
86	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-141
87	Sean	Gosiewski	sean@afors.org	Alliance for Sustainability		2801 21st Ave S Ste 100 Minneapolis MN, 55407 United States	Electronic Service		No	M-25-141
88	Scott	Greenbert	scott@nautilussolar.com	Nautilus Solar Energy, LLC		396 Springfield Aver, Ste 2 Summit NJ, 07901 United States	Electronic Service		No	M-25-141
89	Sarah	Groebner	sgroebner@redwoodelectric.com	Redwood Electric Cooperative		60 Pine St Clements MN, 56224 United States	Electronic Service		No	M-25-141
90	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	M-25-141
91	Cody	Gustafson	cgustafson@mnpower.com			null null, null United States	Electronic Service		No	M-25-141
92	Tom	Guttormson	tom.guttormson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd Ramsey MN, 55303 United States	Electronic Service		No	M-25-141
93	Natalie	Haberman	townsend@fresh-energy.org	Fresh Energy		408 St Peter St # 350 St. Paul MN, 55102 United States	Electronic Service		No	M-25-141
94	Nicholas	Haeg	haeg@fresh-energy.org			12298 Bass Trail Sauk Centre MN, 56378 United States	Electronic Service		No	M-25-141
95	James	Haler	jhaler@southcentralelectric.com	South Central Electric Association		71176 Tiell Dr P. O. Box 150 St. James MN, 56081 United States	Electronic Service		No	M-25-141
96	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-141
97	Donald	Hanson	dfhanson@ieee.org			P. O. Box 44579 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-141
98	John	Harlander	john.c.harlander@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
99	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	M-25-141
100	Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.		701 E. Cary Street	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Richmond VA, 23219 United States				
101	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
102	Tiana	Heger	theger@mnpower.com	Minnesota Power		30 W. Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
103	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	M-25-141
104	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	M-25-141
105	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
106	Mari	Hernandez	mari@irecusa.org	IREC		null null, null United States	Electronic Service		No	M-25-141
107	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	M-25-141
108	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	M-25-141
109	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	M-25-141
110	Casey	Horan	choran@edf.org	Environmental Defense Fund		123 Mission St San Francisco CA, 94105 United States	Electronic Service		No	M-25-141
111	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	M-25-141
112	Frank	Hornstein	frank.hornstein@minneapolismn.gov	City of Minneapolis		350 South 5th Street Minneapolis MN, 55415 United States	Electronic Service		No	M-25-141
113	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington DC, 20006 United States	Electronic Service		No	M-25-141
114	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
115	Jan	Hubbard	jan.hubbard@comcast.net			7730 Mississippi Lane Brooklyn Park MN, 55444 United States	Electronic Service		No	M-25-141
116	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-141
117	Reuben	Hunter	bhunter@madisonei.com	Madison Energy Investments		8100 Boone Blvd Suite 430 Vienna VA, 22182 United States	Electronic Service		No	M-25-141
118	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	M-25-141
119	John S.	Jaffray	jjaffray@jjrpower.com	JJR Power		350 Highway 7 Suite 236 Excelsior MN, 55331 United States	Electronic Service		No	M-25-141
120	Robert	Jagusch	rjagusch@mmua.org	MMUA		3025 Harbor Lane N Minneapolis MN, 55447 United States	Electronic Service		No	M-25-141
121	Chris	Jarosch	chris@carrcreekelectricservice.com	Carr Creek Electric Service, LLC		209 Sommers Street North Hudson WI, 54016 United States	Electronic Service		No	M-25-141
122	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	M-25-141
123	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
124	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
125	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD, 57042 United States	Electronic Service		No	M-25-141
126	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	M-25-141
127	Julie	Jorgensen	julie@greenmark.us.com	Greenmark Solar		4630 Quebec Ave N New Hope MN, 55428-4973 United States	Electronic Service		No	M-25-141
128	Kevin	Joyce	kjoyce@tesla.com			null null, null United States	Electronic Service		No	M-25-141
129	Mahmoud	Kabalan	mahmoud.kabalan@stthomas.edu	University of St Thomas		2115 Summit Ave. Mail OSS100 School of Engineering	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Saint Paul MN, 55105 United States				
130	Camille	Kadoch	ckadoch@raponline.org	Regulatory Assistance Project		50 State Street Suite 3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-141
131	Cliff	Kaehler	cliff.kaehler@novelenergy.biz	Novel Energy Solutions LLC		4710 Blaylock Way Inver Grove Heights MN, 55076 United States	Electronic Service		No	M-25-141
132	Ralph	Kaehler	ralph.kaehler@gmail.com			13700 Co. Rd. 9 Eyota MN, 55934 United States	Electronic Service		No	M-25-141
133	Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC		260 Salem Church Road Sunfish Lake MN, 55118 United States	Electronic Service		No	M-25-141
134	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	M-25-141
135	Jack	Kegel	jkegel@mmua.org	MMUA		3025 Harbor Lane N Suite 400 Plymouth MN, 55447-5142 United States	Electronic Service		No	M-25-141
136	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	M-25-141
137	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
138	Tom	Key	tkey@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-141
139	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	M-25-141
140	Jack	Kluempke	jack.kluempke@state.mn.us		Department of Commerce	85 7th Place East Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
141	Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP		222 South Ninth Street Suite 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
142	Steve	Kosbab	skosbab@meeker.coop	Meeker Cooperative Light and Power		1725 US Hwy 12 E Litchfield MN, 55355 United States	Electronic Service		No	M-25-141
143	Nathan	Kostiuk	nathan.c.kostiuk@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-07 Minneapolis	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55401 United States				
144	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	M-25-141
145	Michael	Krause	michaelkrause61@yahoo.com			1200 Plymouth Avenue Minneapolis MN, 55411 United States	Electronic Service		No	M-25-141
146	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
147	Corrina	Kumpe	ckumpe@mysunshare.com			null null, null United States	Electronic Service		No	M-25-141
148	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-141
149	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
150	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-141
151	Burnell	Lauer	blauer.sundial@gmail.com	Sundial Solar		3209 W. 76th St #305 Edina MN, 55435 United States	Electronic Service		No	M-25-141
152	Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures		315 Manitoba Ave Ste 200 Wayzata MN, 55391 United States	Electronic Service		No	M-25-141
153	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
154	Benjamin	Levine	blevine@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
155	Becky	Li	bli@rmi.org			17 State St 25th floor unit 2500 New York NY, 10004 United States	Electronic Service		No	M-25-141
156	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
157	Carl	Linvill	clinvill@raponline.org			50 State Street Suite #3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-141
158	Phillip	Lipetsky	greenenergyproductsllc@gmail.com	Green Energy Products		PO Box 108 Springfield MN, 56087 United States	Electronic Service		No	M-25-141
159	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicillet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-141
160	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
161	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	M-25-141
162	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
163	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-141
164	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-141
165	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-141
166	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	M-25-141
167	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
168	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-141
169	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
170	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	M-25-141
171	Jason	Maur	jason.maur@renesolapower.com	Renesola Power Holdings, LLC		850 Canal Street 3rd Floor	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Stamford CT, 06902 United States				
172	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-141
173	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-141
174	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	M-25-141
175	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	M-25-141
176	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-141
177	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	M-25-141
178	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	M-25-141
179	Tim	Mergen	tmergen@meeker.coop	Meeker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	M-25-141
180	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	M-25-141
181	Brian	Millberg	fwengineering@comcast.net			695 Grand AVe #222 Saint Paul MN, 55105 United States	Electronic Service		No	M-25-141
182	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
183	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-141
184	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-141
185	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
186	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	M-25-141
187	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
188	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
189	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-141
190	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-141
191	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	M-25-141
192	Anthony	Nelson	amnelson@otpco.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	M-25-141
193	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	M-25-141
194	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
195	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	M-25-141
196	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
197	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy		426 17th Street, Suite 700 Oakland CA, 94612 United States	Electronic Service		No	M-25-141
198	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141
199	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	M-25-141
200	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light		200 1st Street SE PO Box	Electronic Service		No	M-25-141

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				Company		351 Cedar Rapids IA, 52406-0351 United States				
201	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	M-25-141
202	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	M-25-141
203	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-141
204	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	M-25-141
205	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticelllo MN, 55362 United States	Electronic Service		No	M-25-141
206	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
207	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	M-25-141
208	Wendi	Olson	wolson@otpco.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
209	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	M-25-141
210	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
211	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
212	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	M-25-141
213	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-141
214	Dean	Pawlowski	dpawlowski@otpco.com	Otter Tail Power Company		PO Box 496 215 S.	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Cascade St. Fergus Falls MN, 56537-0496 United States				
215	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
216	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	M-25-141
217	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-141
218	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	M-25-141
219	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
220	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	M-25-141
221	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	M-25-141
222	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	M-25-141
223	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	M-25-141
224	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	M-25-141
225	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	M-25-141
226	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-141
227	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	M-25-141
228	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
229	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	M-25-141
230	Generic Notice	Regulatory	regulatory_filing_coordinators@otpco.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
231	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	M-25-141
232	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-141
233	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	M-25-141
234	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
235	Michael	Riewer	mriewer@otpco.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-141
236	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-141
237	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	M-25-141
238	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	M-25-141
239	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-141
240	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
241	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	M-25-141
242	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-141
243	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapolis MN, 55407 United States				
244	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	M-25-141
245	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	M-25-141
246	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	M-25-141
247	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
248	Elena	Saxonhouse	elena.saxonhouse@sierraclub.org	Sierra Club Environmental Law Program		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	M-25-141
249	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	M-25-141
250	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
251	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-141
252	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington MN, 55024 United States	Electronic Service		No	M-25-141
253	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	M-25-141
254	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-141
255	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
256	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	M-25-141
257	Rob	Scott Hovland	rob.scott-hovland@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-141
258	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						CA, 90049 United States				
259	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	M-25-141
260	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	M-25-141
261	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	M-25-141
262	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	M-25-141
263	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-141
264	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	M-25-141
265	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-141
266	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	M-25-141
267	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	M-25-141
268	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	M-25-141
269	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	M-25-141
270	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
271	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	M-25-141
272	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
273	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-141
274	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	M-25-141
275	Karl	Sonneman	karl17@hbci.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	M-25-141
276	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
277	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-141
278	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141
279	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
280	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
281	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	M-25-141
282	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
283	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-141
284	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-141
285	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	M-25-141
286	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	M-25-141
287	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN,	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55373 United States				
288	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	M-25-141
289	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	M-25-141
290	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-141
291	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	M-25-141
292	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
293	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-141
294	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
295	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	M-25-141
296	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	M-25-141
297	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-141
298	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-141
299	Adam	Tromblay	atromblay@noblesce.com	Nobles Cooperative Electric		P.O. Box 58 Slayton MN, 56127-0058 United States	Electronic Service		No	M-25-141
300	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-141
301	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-141
302	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
303	Gary	Van Winkle	gvanwinkle@mylegalaid.org	Mid-Minnesota Legal Aid		111 N Fifth St Ste 100 Minneapolis MN, 55403 United States	Electronic Service		No	M-25-141
304	John	Vaughn	nik@rreal.org	Rural Renewable Energy Alliance		3963 8th Street SW Backus MN, 55435 United States	Electronic Service		No	M-25-141
305	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	M-25-141
306	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	M-25-141
307	Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-141
308	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	M-25-141
309	Robert J.V.	Vose	rvose@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-141
310	Stacy	Wahlund	swahlund@otpco.com	Otter Tail Power Company		215 S. Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-141
311	Sarah	Walinga	swalinga@solarcity.com	Energy Freedom Coalition		3055 Clearview Way San Mateo MN, 94402 United States	Electronic Service		No	M-25-141
312	Kevin	Walker	kwalker@beaconinterfaith.org	Beacon Interfaith Housing Collaborative		null null, null United States	Electronic Service		No	M-25-141
313	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	M-25-141
314	Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-141
315	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	M-25-141
316	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	M-25-141
317	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN,	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101 United States				
318	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	M-25-141
319	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-141
320	John	Williamson	john.williamson@state.mn.us	Minnesota Department of Labor and Industry		443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-141
321	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	M-25-141
322	Danielle	Winner	danielle.winner@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-141
323	Heidi	Winter	hwinter@co.murray.mn.us	Murray County		2500 28th Street PO Box 57 Slayton MN, 56172 United States	Electronic Service		No	M-25-141
324	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	M-25-141
325	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-141
326	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	M-25-141
327	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-8920 United States	Electronic Service		No	M-25-141
328	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188-1022 United States	Electronic Service		No	M-25-141
329	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	M-25-141

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
330	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	M-25-141
331	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-141