2023 TRANSPORTATION ELECTRIFICATION PLAN (TEP)

INTRODUCTION

The transportation sector is the leading source of emissions in Minnesota, and electrification of the transportation sector will bring substantial environmental benefits.[1] Because of this, the State of Minnesota has a goal of electrifying 20 percent of all light duty vehicles by 2030.[2] Xcel shares this ambitious target—by 2030 the company wants to enable one out of five vehicles across its eight-state service territory to be electric. An electric vehicle (EV) powered with Xcel Energy electricity is more than 55 percent cleaner than a conventional gas-powered vehicle, and that percentage will continue to grow as we decarbonize our system. When paired with our groundbreaking corporate objective to reduce electric generation emissions 80 percent below 2005 levels by 2030, with zero carbon emissions across our service territories by 2050, Xcel Energy is striving to deliver significant environmental benefits to our communities, provide cost savings by enabling driving at around or less than $1 per gallon equivalent for residential customers, and keep bills low for all customers.

Accomplishing our transportation and emissions goals requires thoughtful planning to not only support the overall adoption of EVs but, importantly, encourage charging of EVs at beneficial times for our system and all our customers.

This TEP presents proposals for new EV-related offerings as well as modifications to our existing pilots and programs. The Company submits five proposals. These five proposals include:

- An expansion plan for the current EV Subscription Service Pilot,
- A Home Wiring Rebate program to help reduce upfront charging infrastructure costs and encourage managed charging,
- Expanded Residential Advisory Services,
- Support for Electric School Bus projects to support Vehicle-to-Grid (V2G) demonstrations, and
- Bridge funding for both the Fleet EV Service and Public Charging Pilots to continue supporting important commercial electrification projects.

[1] For information on greenhouse gas emissions sources in Minnesota, see the 2023 Biennial Greenhouse Gas Emissions Reductions Report, available at Greenhouse gas emissions in Minnesota 2005-2020 (state.mn.us).
[2] Minnesota Department of Transposition (MnDOT), Minnesota Pollution Control Agency and the Great Plains Institute, Accelerating Electric Vehicle Adoption: A Vision for Minnesota (2019), https://www.pca.state.mn.us/sites/default/files/p-gen4-13.pdf (hereinafter the Vision).

The Company is pleased to provide these proposals and other information for the Commission's consideration at this time and plans to continue to build off the information and proposals in this TEP and the learnings from our pilots in the future. To do so, we intend to file a supplement to this TEP in 2024. Our supplement will likely include a proposal to transition our Fleet EV Service and Public Charging Pilots into permanent programs if the data from the pilot programs supports a permanent program. The supplement may also include additional support for school bus electrification. We look forward to providing additional learnings to inform a potential permanent commercial charging program proposal and to align our school bus efforts with the Minnesota Department of Commerce's (Department) new school bus funding program. Finally, we are also evaluating ways to support the greater development of public direct current fast charging (DCFC) options in our service territory. We look forward to additional discussion on this topic and will look for opportunities to include a future proposal to support public DCFC.

This year's TEP is the first time the Company is submitting our vision of the future of transportation electrification in conjunction with the Integrated Distribution Plan (IDP). The Company submits this TEP pursuant to the Commission's December 8, 2022 ORDER[3], the Commission's August 23, 2023 ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS[4], and 2023 Minn. Laws Ch. 60, Art. 12, § 12, Subd. 2.

Information previously included in the Company's TEP reports, such as information about number of EVs in our service territory, information about public EV charging stations in our territory, and EV forecasts are now included within the IDP. To aid in navigating this new presentation of the TEP, the Company has provided a compliance matrix, as Appendix H1, which shows all reporting requirements related to transportation electrification and provides references to their location in this year's submissions.

Included with this TEP filing are the following appendices:

Appendix H1	Compliance Matrix
Appendix H2	Summary of EV Programs in Other Jurisdictions
Appendix H3	V2G Whitepaper
Appendix H4	EV Subscription Service Pilot Learnings & Final Report

[3] Docket Nos. E999/CI-17-879 and E002/M-21-694
[4] Docket No. E002/M-22-432

Appendix H5	EVAAH – Subscription Pricing
Appendix H6	EV Accelerate At Home (EVAAH) – Subscription Tariff and Customer Service Agreement Proposed Changes
Appendix H7	Overview of Residential Home Wiring Rebate Amounts
Appendix H8	Residential EV Program Portfolio Ecosystem
Appendix H9	Discussion of School Bus Demonstration Proposal Topics from Docket No. E999/CI-17-879
Appendix H10	Commercial EV Pilot Project-by-Project Detail
Appendix H11	Commercial EV Pilot Application Review & Scoring Process
Appendix H12	Cost-Benefit Analysis (CBA)
Appendix H13	Proposed Tariff Changes – Waiving Cost Sharing Requirement

The balance of this TEP is organized as follows:

- *Section I* – Xcel Energy's Transportation Electrification Efforts. Includes discussion of the history of our TEP filings in Minnesota, our transportation electrification efforts in Minnesota, and Xcel Energy's transportation electrification efforts in other jurisdictions.
- *Section II* – Ongoing EV Developments. Includes discussions of proactive grid reinforcement projects, our plans to facilitate greater fleet electrification, public charging infrastructure needs, public charging considerations, improvements we have made to our advisory services, and streamlining our internal processes.
- *Section III* – New Program Proposals and Budgets. Includes discussion and details about the proposals included in this TEP, including reporting requirements, proposed budgets, expected participation, and our CBA analysis of these proposals.
- *Section IV* – Cost Recovery, Accounting Treatment, and Bill Impacts. Includes a discussion of our proposed methods for recovering costs related to our proposals in this TEP, accounting treatment for the proposed rebates, and the bill impacts of our proposals.
- *Section V* – Proposed Tariff Changes. Includes a discussion of the proposed tariff changes, including those ordered by the Commission in our recent electric rate case.

I. XCEL ENERGY'S TRANSPORTATION ELECTRIFICATION EFFORTS

The Company has undertaken substantial efforts to implement EV programs and create customer offerings that address barriers to EV adoption and support broader transportation electrification in its Minnesota service territory. Given the Company's decades of experience building and operating critical energy infrastructure effectively and reliably, the Company is uniquely positioned to help our customers understand the cost savings and emissions reduction benefits of electric transportation and to bring these benefits to our customers.

The Company's guiding principles for its Clean Transportation Program Portfolio, which were developed through work with stakeholders, help inform its EV offerings (Guiding Principles). The Guiding Principles are to:

- Empower customers with information, tools, and options;
- Increase access to electricity as a transportation fuel in an equitable manner;
- Encourage efficient use of the power grid and integrate renewable energy;
- Improve air quality and decrease carbon emissions;
- Ensure reliability, interoperability, and safety of equipment;
- Leverage public and private funding opportunities;
- Provide benefits to all customers, both EV drivers and non-EV drivers; and
- Ensure transparency and measure results.

In addition to designing its EV offerings to align with these Guiding Principles, the Company's current efforts seek to address three key barriers to EV adoption:

- **Lack of information and awareness**. Over the last few years, the Company has provided education and undertaken outreach to inform customers of the benefits of switching to EVs. Despite that, there is more work needed to increase awareness of EVs and their benefits. Enhanced education and outreach can help increase information availability and awareness for EVs and managed charging programs.
- **Upfront costs.** The lifecycle economics continue to improve for EVs. Among other factors, improvements are driven by decreasing battery costs, as well as automobile manufacturers increasing their production and offering a variety of new models in numerous price ranges. However, upfront costs for the vehicles and the necessary charging infrastructure remain a barrier to EV adoption along with an accessible, affordable, and reliable charging infrastructure. The Company helps customers address these upfront cost barriers through our portfolio of residential and commercial pilots and programs.
- **Suboptimal incentives to charge when energy costs are lowest.** Increasing numbers of EVs in the Company's service territory poses a dilemma: EVs could either be a beneficial resource to the grid or create challenges depending on charging patterns. The Company helps manage demand through a

combination of pricing and load management (e.g., "managed charging"), to minimize the costs to the system and to promote efficient grid operation related to this new EV load. Xcel Energy has been a leader in this space, through its pilots and rates approved by Commissions in different service territories, including three-period rate designs for residential and commercial customers that encourage charging during the most beneficial time of day in Minnesota.

In this section, the Company sets out the TEP process in Minnesota and the current state of its transportation electrification efforts in Minnesota as well as other jurisdictions.

A. History of Transportation Electrification Plans in Minnesota

The requirement to submit TEPs originally arose from a Commission Inquiry into Electric Vehicle Charging and Infrastructure.[5] While the Company had begun its transportation electrification efforts several years before, the Company submitted its first TEP to the Commission in June 2019. The Order requiring TEPs also highlighted the Commission's general view of transportation electrification, namely that "electrification is in the Public Interest" and that utilities in Minnesota have a role in "[f]acilitating the electrification of Minnesota's transportation sector."

The Company had been submitting EV Annual Reports since 2016.[6] Those annual reports are intended to be a historical look at the operations of our EV-related programs and activities and feature extensive data about program participation, charging usages, and costs incurred, along with descriptions of our education and outreach activities. The Company submitted its most recent compliance filing on its EV activities in Minnesota as a part of our 2023 Annual EV Report filed in June 2023.[7]

Serving as a companion to the annual reports, the Company's TEPs offer a look forward into the Company's view of transportation electrification, how the Company could facilitate participation in a variety of electrification efforts, and our plans for future programs. The Company filed TEPs concurrently with its EV Annual Reports

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[5] *See* ORDER MAKING FINDINGS AND REQUIRING FILINGS (February 1, 2019), Docket No. E999/M-17-879.
[6] Submitted in Docket No. E002/M-15-111, along with various other dockets related to specific EV programs.

in both 2020 and 2021. However, in the Commission's order accepting the TEP filed in 2020, the Commission approved a biennial filing schedule for TEPs and added the requirement to include greater budget information as well as additional information about system upgrades related to transportation electrification.[8] Subsequent to the filing of our 2021 TEP, the Commission issued an additional order which combined the TEP filing process with the Integrated Distribution Planning process, and suspended the requirement to submit TEPs on June 1 of each biennium. This Order also established a revised set of reporting requirements for both the IDP and the TEP.

In the Spring of 2023, the Minnesota Legislature adopted 2023 Minn. Laws Ch. 60, Art. 12, § 12, Subd. 2., which sets forth a framework for TEPs and the Commission review thereof.

B. Transportation Electrification Efforts in Minnesota

1. *Current Programs*

Table 1 below summarizes the Company's EV-related pilots and programs, including those that have already been approved and those that are under development.

Table 1[9]
Summary of Xcel Energy's EV-related Pilots and Programs

Program	Status	Docket Number	Implementation Status
Residential EV Service Rate	Commission Authorized, Order Date: June 22, 2015	E002/M-15-111	In Operation.
Residential EV Service Pilot	Commission Approved, Order Date: May 9, 2018	E002/M-17-817	Pilot complete and replaced by the permanent EVAAH program.
Fleet EV Service Pilot	Commission Approved, Order Date July 17, 2019; Extension of Pilot Term Approved by	E002/M-18-643	In Operation. Closed to new enrollment – fully subscribed.

[8] *See* ORDER ACCEPTING 2020 TRANSPORTATION ELECTRIFICATION PLANS, ADOPTING ADDITIONAL INFORMATION REQUIREMENTS, AND ESTABLISHING BIENNIAL FILING REQUIREMENT (April 16, 2021), Docket No. E999/M-17-879.
[9] Provided in Compliance with Order Point F.1 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

Program	Status	Docket Number	Implementation Status
	Commission, Order Date December 5, 2022.		
Public Charging Pilot	Commission Approved, Order Date July 17, 2019; Extension of Pilot Term Approved by Commission, Order Date December 5, 2022.	E002/M-18-643	In Operation. Closed to new enrollment – fully subscribed.
Residential EV Subscription Service Pilot	Commission Approved, Order Date October 7, 2019 Modification Approved by Commission, September 28, 2020	E002/M-19-186	In Operation. Closed to new enrollment – fully subscribed.
EV Home Service (known as EV Accelerate At Home [EVAAH]; Successor and replacement program for Residential EV Service Pilot)	Commission Approved, Order Date October 6, 2020	E002/M-19-559	Launched in December 2020. In Operation.
General TOU Service Tariff Pilot	Commission Approved, Order Dates July 16, 2021, February 1, 2023, and June 9, 2023	E002/M-20-86	Pilot with two rate options approved by Commission launched in October 2023. Pilot includes special considerations to encourage and allow participation of EV charging providers.
Multi-Dwelling Unit (MDU) EV Service Pilot	Commission Approved, Order Date July 2, 2021 Modification Approved by	E002/M-20-711	In Operation. Closed to new enrollment – budget fully allocated.

Program	Status	Docket Number	Implementation Status
	Commission, September 21, 2023		
Financial Recovery Proposal EV-related offerings (EV Rebates, Public Fast-Charging Network, Xcel Energy Fleet Electrification acceleration)	Public Fast-Charging Network Approved by Commission, Order Date April 27, 2022	E002/M-20-745	Development of seven fast charging locations in progress. Company fleet electrification was addressed in the Company's rate case (Docket No. E002/GR-21-630).
Load Flexibility Pilot Programs EV-related projects (EV Optimize Your Charge Pilot, V2G Demonstration)	Commission Approved, Order Date March 15, 2022	E002/M-21-101	EV Optimization Pilot (referred to as Optimize Your Charge) is currently in operation. V2G demonstrations not yet in development.

Table 2 below is a summary of the number of participants and total energy consumed for our current EV programs that are in operation. Please note that Peak Demand information is currently available for only our EVAAH program.[10]

Table 2[11]
Xcel Energy's EV-related Pilots and Programs Participation and Energy Usage[12]

EV Program	Number Participants[13]	Total Energy Consumed (MWh)	Peak Demand (MW)
Residential EV Service Rate	1,491	5,692	N/A
EVAAH	1,999	5,793	6.6

[10] Demand information is not available for the other programs either due to it not being tracked (Residential EV Charging Service Tariff and EV Subscription Service Pilot) or due to the metering and billing issues experienced through mid-2023 for our Commercial EV pilots. Our metering and billing issues are discussed in greater detail in our 2023 Annual EV Report submitted on June 6 in Docket No. E002/M-15-111, along with supplements filed on June 30, 2023 and August 23, 2023.
[11] Provided in Compliance with Order Point A.34 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
[12] Data from our 2023 Annual EV Report submitted in Docket No. E002/M-15-111.
[13] Represents actively participating customers. For the Commercial EV Pilots (Fleet, Public, and MDU), that only includes sites that are in-service.

EV Program	Number Participants[13]	Total Energy Consumed (MWh)	Peak Demand (MW)
EV Subscription Service Pilot	127	590	N/A
Fleet EV Service Pilot	13	779,472	Unavailable at this Date
Public Charging Pilot	60	388	Unavailable at this Date
MDU Pilot	6	10	Unavailable at this Date
Residential EV Optimize Your Charge Pilot	98	N/A	N/A
Commercial EV Optimize Your Charge Pilot	1[14]	N/A	N/A

We provided greater information about all our ongoing EV efforts in our 2023 EV Annual Report.[15]

2. *Spending on Transportation Electrification*

Table 3 provides a summary of the Company's expenditures for its transportation electrification portfolio and efforts for the previous 5 years. The Company notes that it has included forecasted spend for the remaining months of 2023.

Table 3[16]
Transportation Electrification Spending: 2019 – 2023
($ in Millions)

Budget Category	Capital	O&M	Marketing and Communications	Other	Total
Distribution	$1.4	$0.0	$0.0	$0.0	$1.4
EVSI	$14.9	$0.0	$0.0	$0.0	$14.9
EVSE	$1.9	$0.0	$0.0	$0.0	$1.9

14 This represents one fleet, participating via six charging stations.
15 Filed June 6, 2023 in Docket No. E002/M-15-111, available here: searchDocuments.do (state.mn.us). Provided in Compliance with Order Point F.9 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
16 Provided in Compliance with Order Points A.26.i and F.10 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

Budget Category	Capital	O&M	Marketing and Communications	Other	Total
O&M & Mrktg Comm.	$0.0	$2.3	$1.7	$0.0	$4.0
Cost of Goods Sold[17] (Pre-Pay Option)	$0.0	$0.0	$0.0	$0.7	$0.7
EV Cost Tracker (Deferred)	$0.0	$0.0	$0.0	$2.6	$2.6
Total	$18.2	$2.3	$1.7	$3.3	$25.5

3. Distribution System Upgrades Responsive to Company Program Participation[18]

With respect to residential, EV-related system upgrades, we are not aware of any distribution system upgrades that have been made to date.

The drivers for residential EV-related distribution system upgrades stem from two primary causes: individual residential load increases and cumulative incremental growth. Identifying the need for these upgrades is particularly difficult. The primary reason is that there are situations where one or multiple customers begin charging an EV—thus adding load—without notifying the Company. In these situations, the Company typically becomes aware of the need for a system upgrade when those individual customers, or the customers being fed from the same transformer, notice and report a negative impact on their electric service (e.g., flickering lights, low voltage, momentary loss of power, or other similar effects). Once an issue is known, the Company assesses the system, considering existing loading, number of customers, equipment being used, size of the equipment, service distance, and service transformer size. Whether the customer will be responsible for the costs of any such upgrades is determined from this analysis.

Historically, determination of customer responsibility was governed by a revenue justification policy called the revenue/expenditure ratio. If construction costs are in excess of 3.5 times the anticipated increased annual revenue, then the customer is

[17] Represents the cost of charging equipment for customers who choose the pre-pay option and paid for the equipment upfront.
[18] Provided in Compliance with Order Point A.35 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

responsible for the excess expenditures.[19] This is still the case for customers who are not participating in one of the Company's tariffed EV programs and pilots. However, since approximately 2020, Company policy is to no longer charge customers for distribution system upgrades if they are participating in one of our EV options.[20]

In contrast, with respect to public and fleet charging projects and the growth in those applications, the Company has begun to see the need for additional EV-related system upgrades. Table 4 below shows the total upgrade costs for active projects by Company program since June 2021, the date of our last TEP filing. The table also includes the average costs per upgrade. These costs were paid by the Company as participants in the commercial EV pilots are not responsible for system upgrade costs.

Table 4
Distribution System Upgrade Costs
June 2021 through September 2023

Program	Total Upgrade Cost	Number of Projects Requiring Upgrades	Average Upgrade Cost Per Project
Fleet	$191,974	10	$19,197
Multi-Dwelling Unit	$12,436	1	$12,436
Public Charging	$948,112	71	$13,354

4. *Residential and Managed Charging Options*[21]

Our Residential EV Service Rate launched on August 1, 2015, as a voluntary option to provide residential customers an incentive to charge their EVs during off-peak hours. We then developed a Residential EV Service Pilot in 2018, which has subsequently been replaced by our permanent EVAAH program in 2020, to provide a turnkey service that delivers ongoing charging and upfront cost savings to customers through attractive off-peak time-of-use (TOU) pricing and the avoidance of installing a second meter, the latter of which is required to take service under the original Residential EV Service Rate. Since the program launched, participation has increased from 100 customers to more than 2,000, and we continue to observe high customer (>90 percent) satisfaction and charging activity occurring outside of on-peak hours. For the

[19] Provisions are included in our Electric Rate Books in Section 6, Sub-section 5.2 (Sheet Nos. 6-26 and 6-27)
[20] We are proposing a change in our EV-related tariffs to reflect this policy more clearly. The proposed changes are shown in Appendix H13.
[21] Provided in Compliance with Order Points F.2.b and F.4 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879 and Order Point 4A of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.

latest information regarding the EVAAH program, please refer to our 2023 EV Annual Report. EVAAH is the only permanent EV infrastructure program that the Company operates in Minnesota. As discussed in detail below, we have recently proposed modifications to streamline the customer experience and enhance the program's eligibility requirements.

Our Residential EV Subscription Service Pilot was launched in February 2020. That pilot provides many of the same benefits of EVAAH but incentivizes customers to charge off-peak for a preset monthly fee, offering customers certainty in monthly charging costs.

We launched our MDU EV Service Pilot in 2021, which is designed to promote and study Multi-Dwelling Unit (MDU) charging and increase charging availability to a larger range of customers in the residential segment. To facilitate greater EV access at affordable-housing MDUs, the Company has partnered with HOURCAR to install charging equipment at several affordable-housing locations through this pilot. These HOURCAR sites are designed to provide easier access, through car sharing, to customers who may not utilize electrified transportation in other ways. We are in the process of completing 35 projects in this pilot and are looking forward to collecting learnings to help inform future program proposals for this unique residential customer segment.

Just last year, we launched a managed charging pilot as part of our Load Flexibility portfolio, called Optimize Your Charge.[22] This program incentivizes customers to charge during set off-peak times with an annual bill credit. Customers can select their preferred off-peak charging window and set their charging schedule via their vehicle or charging station in accordance with that window. If customers charge at least 25 percent of the time within that off-peak timeframe, they will receive a bill credit.

The Company recently proposed modifications to its EVAAH program that intend to streamline the customer experience and enhance the program's eligibility requirements.[23] Of particular importance, these modifications would simplify the program by incorporating removal fees into the monthly customer charge, updating customer charge pricing to reflect updated Company costs, and broaden customer eligibility by expanding the definition of eligible EVs and enabling a Bring-Your-Own-Charger (BYOC) charger option.

[22] Docket No. E002/M-21-101.
[23] *See* our September 12, 2023 Petition in Docket No. E002/M-19-559.

In this TEP, the Company is proposing two key programs to help facilitate greater residential charging options that are geared toward reducing barriers to EV adoption and increasing managed charging participation. The first proposal is to expand the successful EV Subscription Service Pilot as a permanent, tariffed offering under EVAAH, as the *EV Accelerate At Home – Subscription* option. The Company provides more details on this proposal in Section III.A. Second, the Company is proposing to introduce a *Home Wiring Rebate Program* that will help reduce high upfront charging infrastructure costs associated with charging at home and drive more managed charging. This proposal is discussed in Section III.B.

5. *Fleet Electrification*[24]

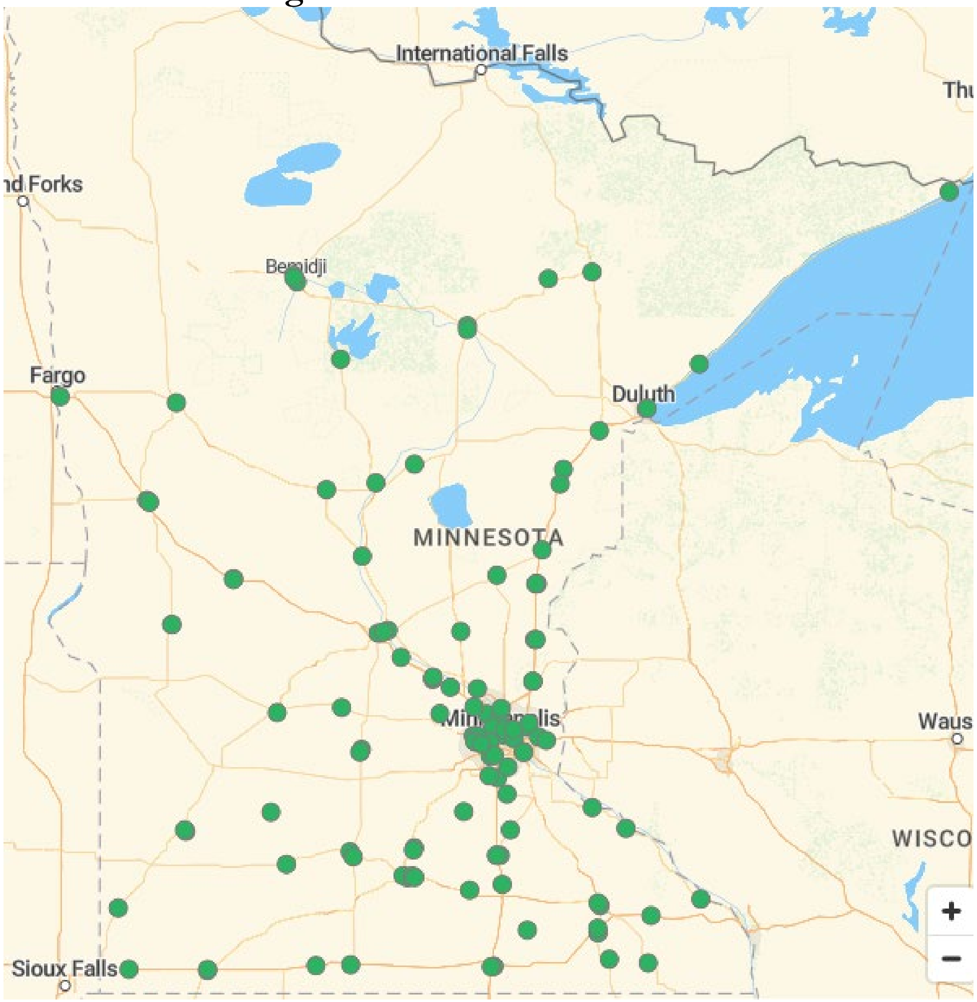
The Company currently operates a Fleet EV Service Pilot, which provides make-ready EV supply infrastructure (EVSI) to participating public sector fleets to reduce upfront costs and technical barriers to fleet adoption of EVs.[25] The pilot has helped the Company understand how charging behavior and utilization of TOU rates impacts public sector fleet operators and the electric grid. We now currently have 14 completed, in-service projects with an additional 10 moving through design and construction phases. Projects consist of many municipalities across a variety of civic departments, public transit service providers, state and regional agencies, and a school bus operator. The Company has closed the pilot to incremental enrollment as it has reached its approved budget, and we are working on collecting data and learnings with the existing pool of projects to help inform future program proposals.

6. *Public Charging*[26]

Public fast chargers play an essential role in the EV ecosystem. The need for fast charging applies to EV drivers across a variety of use cases, from planned and emergent charging during long-distance travel to everyday charging for drivers that live in multi-unit dwellings without charging access. Figure 1 below shows the locations of Minnesota's existing DCFC stations as of August 2023, showing a concentration of stations in the Twin Cities metro.[27]

[24] Provided in Compliance with Order Point F.2.d of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
[25] The Fleet EV Service Pilot was approved by the Commission. Order Dated July 17, 2019 in Docket No. E002/M-18-643
[26] Provided in Compliance with Order Point F.2.a of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
[27] U.S. Department of Energy Alternative Fuels Data Center (August 2023)

Figure 1
Existing Public DCFC Station Stations[28]



Shown above, within the Company's service territory, there are 57 fast charging stations, referred to hereafter as charging hubs, which include multiple individual charging ports. The 57 fast charging stations in the Company's service territory include 214 ports.

Nationally, EV drivers' satisfaction with public fast charging declined from July 2022 to July 2023 across all charging providers, except Tesla and SemaConnect.[29] Table 5 below shows the public fast charging hubs and ports within the Company's service territory broken out by charging network provider. Approximately two thirds of these

[28] Alternative Fuels Data Center (Data as of August 2023)
[29] J.D. Power 2023 U.S. Electric Vehicle Experience Public Charging Study – Confidential information. Please note that SemaConnect is now known as Blink Charging.

ports are Tesla chargers, which historically have been open for use only by Tesla drivers.

Table 5
Public Fast Charging Hubs and Ports in the Company's MN Service Territory by Network Provider[30]

Network Provider	Hubs	Charging Ports
Blink Network	2	2
ChargePoint Network	7	7
Electrify America	2	12
EV Connect	7	14
eVgo Network	1	6
Non-Networked	10	14
SHELL_RECHARGE	4	8
Tesla	15	142
Volta	1	1
ZEFNET	8	8
Total	**57**	**214**

The decline in driver satisfaction with fast charging appears to have been driven primarily by sharp drops in driver satisfaction across three critical factors of the public fast charging experience: charger availability, speed of charging, and ease of charging. In Minnesota, like other Midwestern states, EV drivers report higher levels of satisfaction with public fast charging than the national average, though they face the same industry-wide issues.[31] According to J.D. Power, public charging is the least satisfying aspect of owning an EV.[32]

Alongside an overall decline in drivers' satisfaction with public fast charging over the past year, the public fast charging market underwent significant changes this summer. Since May, most major vehicle original equipment manufacturers (OEMs), charging equipment manufacturers, and public fast charging network providers in the United States announced plans to begin using Tesla's North American Charging Standard (NACS) charging connector design.[33] Tesla has also announced plans to open its

[30] Ibid.
[31] Ibid.
[32] J.D. Power 2023 U.S. Electric Vehicle Experience (EVX) Ownership Study – Confidential information
[33] Opening the North American Charging Standard | Tesla

Supercharger network,[34] which has achieved the highest public fast charging satisfaction rates in the industry for three years in a row,[35] to various non-Tesla drivers.

Beginning in 2025, non-Tesla vehicle OEMs, including Ford and General Motors, have committed to equipping their vehicles with a NACS charging port. Prior to these announcements, the most widely used charging standard in the United States had been the Combined Charging System (CCS) port, which is also the standard required for charging stations funded by the federal National Electric Vehicle Infrastructure (NEVI) Program.

It remains to be seen how the industry's alignment around the NACS charging port design and the availability of Tesla's Supercharger network will impact driver satisfaction and the future of the EV-charging industry. For example, unlike CCS, NACS is not yet an official charging standard certified by an international standards organization.[36] This means there may be significant challenges in achieving interoperability among EVs and public charging networks that use NACS, potentially delaying a best-in-class public fast charging experience for drivers. Additionally, a lot more goes into creating a reliable, customer friendly charging experience outside of the charger connector, such as software and system management, communication networks, charger cables, etc., which also remain to be standardized.

[34] FACT SHEET: Biden-Harris Administration Announces New Standards and Major Progress for a Made-in-America National Network of Electric Vehicle Chargers | The White House; Ford EV Customers to Gain Access to 12,000 Tesla Superchargers; Company to add North American Charging Standard Port in Future EVs (May 25, 2023) https://media.ford.com/content/fordmedia/fna/us/en/news/2023/05/25/ford-ev-customers-to-gain-access-to-12-000-tesla-superchargers--.html; GM embraces Tesla's EV charging system, Wall Street cheers, David Shepardson and Joseph White (June 9, 2023) https://www.reuters.com/technology/gm-ceo-discuss-future-ev-charging-with-musk-twitter-2023-06-08/; Volvo just became the latest EV maker to move to Tesla's charging standard, John Rosevar (June 27, 2023) https://www.cnbc.com/2023/06/27/volvo-adopts-teslas-ev-charging-standard.html; Polestar will adopt North American Charging Standard to enable access to Tesla Supercharger network in USA and Canada (June 29, 2023) https://media.polestar.com/us/en/media/pressreleases/669136; Mercedes-Benz adopts Tesla's NACS, first German automaker to do so, Fred Lambert (July 7, 2023) https://electrek.co/2023/07/07/mercedes-benz-adopts-tesla-nacs/

[35] J.D. Power 2023 U.S. Electric Vehicle Experience Public Charging Study – Confidential information

[36] SAE is in the midst of a process to standardize NACS as J3400 by the end of 2023: The Roadmap for Tesla's NACS EV Plug Is Plaid-Fast (msn.com)

7. *Education and Awareness (Advisory Services)*[37]

The Company operates an expansive set of EV education and awareness initiatives to inform customers and the public about the benefits of owning an EV and our EV-related rates and programs. These initiatives, known as the Company's Advisory Services, are available via multiple channels, including sponsored public events, digital media, online tools, and offerings that help dealers and other trade allies such as electricians, address barriers to selling EVs and installing charging infrastructure.

a. *Education and Awareness Activities*

A focus of the Company's efforts to educate and inform customers about the benefits of EVs and the Company's programs is to connect with them by providing relevant information where they are engaging with digital platforms and content. Advertising channels include search engine marketing, social-media, digital media, and traditional media such as TV. Calls to action are intended to drive traffic to our website and resources for EV information and programs, such as the EV Advisor Online Tool, discussed in more detail below.

The Company also sponsors public events to engage relevant audiences, aligning with partners who also support increased adoption of EVs and access to the benefits of transportation electrification. Our educational assets include our interactive "EV garage" that offers customers a simulated home charging set up and hands-on experiences with EVs and home charging equipment. We also provide various EV models at events for display and "ride & drive" experiences.

b. *EV Advisor Online Tool*

Education and Awareness activities, like search engine optimization and social media campaigns, are all primary customer engagement drivers and designed to direct to our EV website and EV Advisor Online Tool.

The EV Advisor Online Tool provides personalized information on EVs and programs to help customers find the right option for their lifestyle and charging needs, and the Company has included funding in the budgets set forth in this filing to improve the Online Tool. The Online Tool currently provides the following customer resources:

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[37] Provided in Compliance with Order Point F.7 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

- Various new and pre-owned EVs available in the market and options to compare models;
- Environmental impacts of EVs;
- Costs and benefits of EVs, including fuel and maintenance costs;
- Auto Dealers who are knowledgeable about EVs and current inventory at select dealer locations;
- Rate and managed charging program recommendations, including information encouraging customers to charge during off-peak periods.

c. Trade Ally Engagement

Trade Allies are experienced businesses offering EV industry goods and services that the Company partners with to help make customers' EV journeys easier. For example, the Company partners with important trade allies like electricians that have experience installing Level 2 chargers and auto dealers who sell EVs. We currently provide local dealer partners with services that directly address barriers they face selling EVs, including EV training for personnel, information, resources, and tools to be shared with mutual customers, and plan to proactively grow and foster this network over time. Trade allies can also help share information about other resources to support transportation electrification such as state vehicle purchase rebates.

Electricians are important trade allies and sources for referrals to our managed charging programs. The Company will continue to build its trade network for electricians who are interested in installing EV charging infrastructure. The Company conducts trainings, which include specific information about the EV market, Company electric rates, managed charging programs, renewable programs, and specific metering and distribution standards and considerations. The Company believes that continued collaboration with electricians will help enable an improved customer experience and lead to increased enrollment in managed charging programs. More details about the Company's Trade Ally Engagement activities can be found in our 2023 Annual EV Report.[38]

C. Transportation Electrification Efforts in Other Jurisdictions

In addition to its transportation electrification efforts in Minnesota, Xcel Energy has extensive transportation electrification efforts in market in its other jurisdictions. Xcel Energy has received approval of EV programs in Colorado for Public Service

[38] Submitted June 6, 2023 in Docket No. E002/M-15-111.

Company of Colorado (PSCo), in Wisconsin for Northern States Power Wisconsin (NSP-W), and in New Mexico for Southwestern Public Service Company (SPS). In addition, Xcel Energy has also submitted proposals for EV programs in Texas for SPS.

Most notably, the Company has seen great success in Colorado through the implementation of its EV charging programs. The Colorado programs have seen continued growth this year, with a significant uptick in demand for the EVSI programs, which include commercial and multifamily offerings. In October 2023, the Company reported an increase from 69 to 162 active ports in EVSI programs since our last report in April 2023, and 1,283 additional ports in the pipeline. Overall satisfaction ratings with our EVAAH program in Colorado are very high, at 96 percent. When participants were asked if they would refer EVAAH to a friend, 94 percent of respondents reported that they are highly likely to recommend it.[39]

The Company continues to pursue EV programs in other jurisdictions as well, with residential, commercial, and multifamily EV charging infrastructure programs approved in Wisconsin.[40] The Company also has proposed additional investments in public charging and expanded advisory services in Wisconsin that are currently pending regulatory approval.[41] Table 6 below summarizes the approved EV charging infrastructure investments in other jurisdictions, along with the amount of investment we have requested but is not yet approved.

Table 6
Cumulative EV Charging Infrastructure Investment by State
($ in Millions)

State	Approved Investment	Pending Approval
Colorado	$108	$439
Wisconsin	$22	$2
New Mexico	$3	$0
Texas	$0	TBD[42]

[39] Colorado TEP Semi-Annual Report - Oct. 2023
[40] Final Order, Application of Northern States Power Company-Wisconsin for Approval of Electric Vehicle Programs, Docket No. 4220-TE-113 (July 11, 2023)
[41] Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rate, Docket No. 4220-UR-126
[42] While SPS has proposed new programs in its current rate case, the recovery of any costs associated with these EV programs will be proposed in a subsequent rate case.

Appendix H2 provides a detailed list of relevant filings in other jurisdictions with a list of the included pilots and programs. The appendix also includes links to the filings or instructions of how to find the filings on the relevant utility commission website.

II. ONGOING EV DEVELOPMENTS

In addition to the pilots and programs currently in place and described above, the Company continues to assess and develop programming to support transportation electrification in its service territory. In this section, the Company presents its ongoing EV-related program developments, analysis of how it can best meet customer EV-related needs in the future, and new program proposals.

A. Proactive Grid Reinforcement in Anticipation of EV Growth

A key facet of access to affordable, reliable charging is a reliable electric grid. Specifically, supplying the infrastructure to integrate the number of EVs detailed in the State's 2030 goal presents unprecedented challenges to the electric distribution system and the existing planning processes for adding capacity. The three primary challenges are discussed here.

First, the scale and timing of a new commercial EV load, such as a public charging hub or a fleet charging site, is considerably different than other similarly sized load additions. The electricity demand from a new public charging hub or a fleet charging site could exceed 1MVA of peak demand capacity, matching the peak demand capacity of a new manufacturing facility. But unlike a new manufacturing facility that gives significantly more lead time, the Company rarely has more than a year of advance visibility and coordinated involvement for new commercial EV load. This then reduces the time the Company has to prepare the grid for the additional load.

Second, commercial EV loads do not impact the grid uniformly. These loads are typically concentrated in specific areas. Fleets can develop in "clusters" and public charging hubs often target locations near large traffic flows. The Company anticipates that, as EV adoption moves into all vehicle segments (light-, medium-, and heavy-duty vehicles), the concentrated demand from new fleet charging sites and public charging hubs will quickly outpace the Company's available capacity in specific areas, especially in already developed metropolitan areas.

Third, distribution system upgrades, such as feeder and substation capacity upgrades, can have project lead times ranging from one to ten years, depending on the magnitude of new load and the capacity headroom available across the impacted feeder, upstream substation, and upstream transmission infrastructure. Combined with the relatively short lead times for commercial EV project planning, the corresponding delays in system upgrades will likely delay charging infrastructure installation timelines and add costs for anyone deploying public and fleet charging. Those delays and cost increases can lead to a variety of problems, including abandoned projects, public charging gaps, and lost fleet electrification opportunities. [43]

B. Plans to Facilitate Greater Fleet Electrification[44]

Although the Company has closed the Fleet EV Service Pilot to additional enrollment, we have received and continue to receive expressions of interest from customers who are ready to pursue fleet electrification with support from the Company. This interest is encouraging and is demonstrative of the electric fleet segment growing with more EVs suited for fleet operation hitting the market and fleet operators embracing EV benefits[45], as well as overall satisfaction and interest in the Pilot and its services. To meet this project-ready customer demand and advance their transportation electrification goals, we propose an increase in funding for the Fleet EV Service Pilot as a bridge to maintain service to customers and sustain, rather than stifle, the momentum in the market for fleet electrification while we evaluate the pilot's overall effectiveness and contemplate long term plans. We discuss this bridge proposal in more detail in Section III.D.

Further, as discussed in greater detail in Sections II.A and II.G, proactive grid reinforcement and streamlining the Company's internal processes will be critical to prepare for increased fleet electrification in our service territory.

C. Public Charging[46]

As EV adoption moves beyond early adopters to mainstream consumers, and if public charging installations continue to significantly lag EV adoption in the state, it is

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[43] The Company reviews the progress it has made in location-specific forecasting of new EV load using LoadSEER scenario modeling in Appendix A1 of its Integrated Distribution Plan.
[44] Provided in Compliance with Order Point F.2.d of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
[45] *Electrifying Fleets: From Pilot to Full Scale* from Rocky Mountain Institute Electrifying Fleets: From Pilot to Full Scale – RMI and *Global EV Outlook 2023* from International Energy Agency Global EV Outlook 2023: Catching up with climate ambitions (windows.net) both point to an increase in fleet electrification
[46] Provided in Compliance with Order Point F.2.a of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

foreseeable that Minnesotans' public fast charging satisfaction perceptions may drop as chargers become less available.

Lagging public charging availability impacts the EV ecosystem beyond driver satisfaction. Availability of public charging is a critical factor in whether consumers consider an EV or not. For two years in a row now, nearly half of consumers not considering an EV as their next vehicle cited the lack of public charging as their number one reason for non-consideration[47].

The Company agrees with the Commission[48] that the electric utility has a vital role to play in the expansion of public charging. The Company is also uniquely positioned to support entities providing charging access and to support EV drivers at each point of project implementation, including supplying electrical capacity when and where it is most needed; reducing upfront costs by providing charging infrastructure or incentives; and supporting education and awareness efforts to help current and prospective EV drivers become confident in charging their EV. As we describe in more detail below, the Company is in the process of developing new programs to support these efforts.

1. *Plans to Facilitate Greater Public Charging Access*

Although the Company has closed the Public Charging Pilot to additional enrollment, the Company continues to receive expressions of interest from customers who are ready to pursue public charging projects and who are interested in support from the Company. This interest is evidence of the potential continued growth of the public charging market and confirms interest and satisfaction with the Pilot's design and services. To meet this identified, project-ready customer demand and to advance our customers' transportation electrification goals, in this TEP the Company is proposing a near-term increase in funding for the Public Charging Pilot. Additional funding will serve as a bridge to maintain service to customers and to support, rather than stifle, the momentum in the market while the Company continues to evaluate the Pilot's overall effectiveness. Additional funding and time to gather greater learnings will help guide long term plans for supporting public charging. The Company discusses this bridge proposal in more detail later in this TEP.

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[47] J.D. Power 2023 U.S. Electric Vehicle Consideration Study– Confidential Information
[48] Order Point 5 of the Commission's February 1, 2019 ORDER MAKING FINDINGS AND REQUIRING FILINGS specifically lays out the Commission's expectations regarding the role of utilities in encouraging EV adoption and integration.

2. *Public Charging Experience in Colorado*

The Company also has gathered experience with public charging infrastructure implementation through sharing of data with Public Service of Colorado (PSCo), the Xcel Energy operating company in Colorado. Through this experience, Xcel Energy has gained learnings that can be utilized across jurisdictions and for the benefit of the Company. These learnings may be demonstrative of challenges that the Company can expect to see in Minnesota. For example, PSCo is facing challenges that are impacting its ability to deliver service with the reliability and customer experience that the Company expects. In its April 2023 semi-annual report to the Colorado Public Utilities Commission, the Company highlighted items such as inadequate charger power output due to hardware limitations, lack of power sharing, and issues with pricing and payment related to the vendors' hardware and software.[49] Additional vendor challenges that have been observed include outdated firmware, loss of network connectivity, and lack of credit card payment terminals on the chargers. The Company has worked diligently with the charging management vendor and has been disappointed by the lack of effort and urgency from the vendor and its subcontractors to resolve issues. After a very brief initial period of public operation in late 2022 – early 2023, given the number of issues and slow resolution time, the Company has not yet reopened its first public fast charging station installed in Colorado to the public, but plans to do so when the key vendor challenges have been addressed.

To better understand and control the issues prior to site re-opening in Colorado, the Company has undertaken an extensive in-person testing process involving Company personnel taking EVs to the station and attempting to charge. Since April 2023, the Company has performed test charging sessions at least once per month, with a total of 39 charging sessions totaling 647 minutes of charging time. Through these sessions, the Company has frequently experienced instances of failing to initiate a charge. The failure causes appear to be unpredictable, and often cannot be explained by the Company's charging management vendor. Examples of issues observed during the testing sessions include charging session not initiating due to "communication problems", charging session terminating suddenly due to "internal problem", and charger randomly showing unavailable in the charging vendor's mobile application. In aggregate, the frequency and unpredictability of the vendor's software gives the Company concern that the chargers will operate without issue once the chargers are opened to the public. Additionally, we have recently learned that the current charging management vendor is exiting its third-party support focus of its business. The

[49] *2021-2023 Transportation Electrification Plan Semi-Annual Report* (April 2023), Proceeding No. 20A-0204E

Company is exploring options for a different charging management vendor to better meet customer expectations and provide the necessary level of service.

In various important aspects, Xcel Energy's Colorado experience is representative of the challenges facing the public fast charging industry nationwide and illustrates the fact that the hardware and charging management software ecosystem is still developing, having not yet reached a mature state. The Company's experience also demonstrates the challenges presented when vendors enter and exit the business. The Company has reached out to other utilities, consultants, and engineering firms to help develop its approach to resolving these issues; feedback received is that the Company's challenges are very common in the industry. For example, a study focused on fast chargers in the Bay Area of northern California demonstrated strong concern about public charging – on both distances between chargers and charger reliability – in addition to the results of one study showing only approximately 70 percent of public fast chargers were operational when assessed in 2022.[50]

Additionally, in 2022 the Company partnered with ChargerHelp! to survey the landscape of public chargers specifically in the Company's service territory in Minnesota. The ChargerHelp! survey found only about 62 percent of public fast chargers were operational. Of the 21 fast chargers they assessed, 13 were found to be operational, and the eight fast chargers that were unable to charge a vehicle suffered from one or more issues related to physical damage, error messages on the screen, firmware inoperability issues, and other reported problems. These results are all consistent with the conclusions J.D. Power has drawn about public charging nationwide discussed above.

The Company is determined to deliver a strong customer experience as we prepare to re-open the first public fast charging site in Colorado and commission additional public fast charging sites in Colorado and other jurisdictions, which is difficult given the inherent charging software and hardware issues noted above.

3. Next Steps for Company-Owned Public Charging Pilot

Given the challenges thus far, the Company is proceeding forward with a great deal of caution in close coordination with our site hosts, which may lead to sites in Minnesota and other jurisdictions opening later than initially planned to allow more time for issue resolution. The Company continues to work with its charging vendors daily to address

[50] See David Rempel et al. Reliability of Open Public Electric Vehicle Direct Current Fast Chargers, https://arxiv.org/ftp/arxiv/papers/2203/2203.16372.pdf.

the outstanding items and has developed a strategic soft launch plan that will allow for more thorough testing, monitoring, and troubleshooting as each site is brought online. Additionally, the Company plans to invite customer feedback on the charging experience via a sign with a QR code that will be placed at our charging locations. We will be actively monitoring public charging feedback through organizations such as PlugShare to address issues and concerns quickly that may not be readily available through network monitoring. As noted, the Company is exploring options for a different charging management vendor to better meet customer expectations and provide the necessary level of service.

4. *Divestment of Company-owned Public Charging*[51]

The Company is anticipating substantial completion of construction on six Company-owned public DCFC stations this year and one additional site in 2024. Site opening for public use is expected to occur in 2024 for all stations. As a part of the Order approving the Company's DCFC station program, we are required to provide a discussion of divestment issues and strategies as a part of this and future TEP filings.[52]

As our entry into the DCFC market is still in its infancy, we have not had the opportunity to explore divestment approaches for this small-scale Company-owned and operated DCFC development and believe that it is currently premature to do so. Further, in response to the Commission's recent order[53], we have provided an assessment of the public fast charging market and an overview of ways in which we can support it in this TEP. The Company plans to continue coordinating with customers, stakeholders, industry actors, and the Commission, to help identify how we can best foster an affordable, reliable, and accessible public charging market moving forward.

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[51] Provided in Compliance with Order Point F.5 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

[52] *See* ORDER APPROVING PUBLIC CHARGING STATION PROPOSAL (April 27, 2022), Docket No. E002/M-20-745, Order Point 8

[53] *In the Matter of the Petition of Northern States Power Company for Approval of a Public Charging Network and Electric School Bus Pilot and Program Modifications*, Docket No. E002/M-22-432, ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS, Order Point 3.B. (Aug. 28, 2023).

5. *Future Program Options to Support Public Charging*

In response to the Commission's Order from its decision on August 23, 2023[54], the Company provides a high level comparison of ways in which it could support efficient, cost-effective development of Minnesota's public DCFC charging network and the pros and cons of each option, with the goal of the Company supporting the public charging market and facilitating greater public charging availability within its service territory. Here, the Company considers four potential options:

- EVSI Only,
- EVSI Plus Rebates for Public EV Charging Equipment,
- Utility Ownership and Operation of DCFC, and
- DCFC Partnership.

a. *EVSI Only*

One programmatic model for how the Company could support the public charging market would be to expand its existing EVSI, or make-ready infrastructure pilot (the Public Charging Pilot).

Under this approach, utilities can lower public charging installation costs for entities looking to deploy public charging. This approach also simplifies the construction process since the Company will procure, design, construct and operate the EVSI and distribution equipment needed to energize DCFC charging stations. These services are provided at no direct cost to the participating customer, and therefore, significantly lowers their overall financial outlay to build charging stations making the Company's Minnesota service territory an attractive location to do business. A program where the Company provides EVSI would also ensure that public charging infrastructure adheres to the Company's standards for high-quality labor, safety, and reliability. A future public charging EVSI program would take on a similar form to the Pilot that exists today, but would likely incorporate changes to operational processes, requirements, and other program design elements based on forthcoming Pilot learnings.

[54] *In the Matter of the Petition of Northern States Power Company for Approval of a Public Charging Network and Electric School Bus Pilot and Program Modifications*, Docket No. E002/M-22-432, ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS, Order Point 3.Biii. (Aug. 23, 2023).

There is less assurance regarding equity, accessibility, and affordability, for this approach, as compared to a utility owned and operated model. However, these drawbacks can be mitigated by including stipulations and requirements into the program design, such as by implementing an application and site review and scoring process to ensure a focus and prioritization on these objectives.

b. EVSI Plus Rebates for Public Charging Equipment

The Company could also support the public charging market by offering an EVSI program coupled with rebates for the cost of DCFC equipment. The pros, cons, and considerations of this approach take on the same form as the EVSI-only alternative discussed above but further reduce the significant upfront cost burden associated with fast charging equipment by providing rebates for the cost of the charging stations themselves.

Like the EVSI-only option, incorporating a thoughtful application and site review and scoring process into the program design is an important consideration for the program to ensure funding is stewarded in an equitable manner. Further, enhanced (higher) rebate amounts could be made available to customers who install public charging in disadvantaged communities or areas with a significant charging accessibility gap. Additionally, while federal and state funding opportunities for public DCFC installations exist today, notably, the NEVI program, the amount of funding will not meet the full scope of public charging demand across the state. Utility support, including EVSI and rebates, can help complement other funding opportunities and bridge this overall funding gap and ensure that public fast charging availability extends beyond federally designated alternative fueling corridors.

The Company notes that a variation of this approach could also involve rebates for both EVSI and DCFCs. With this variation, participating customers would procure and install both the EVSI and charging equipment, and the Company would reimburse participants for the equipment and installation costs. This approach involves similar financial pros and equity and accessibility considerations as previously discussed. An additional con of this modified approach is that the EVSI would be procured and installed outside of utility oversight.

For utility-supported rebate programs, just like all utility voluntary programs, cost recovery approaches are an important consideration. Recovering rebates treated as an annual expense has a higher immediate impact on customer bills, and the Company believes that alternative approaches are warranted to better match the costs of rebate-programs with the delivery of benefits associated with these programs over the long term, and to mitigate rate impacts. The use of a regulatory asset to recover rebate costs, in combination with a return on that regulatory asset equal to the weighted average cost of capital of the Company, can balance the risks and benefits associated with offering a utility rebate to support the costs of chargers and/or EVSI.[55]

c. Utility Ownership and Operation of DCFC

In the Company's now withdrawn Clean Transportation Portfolio proposal in Docket No. E002/M-22-432, we provided an overview of how a Company owned and operated public DCFC network could function at scale. Through this approach, the Company would partner with a third-party network provider to build, operate, and maintain a public EV charging network. The Company would recruit site hosts based on locational charging needs and site hosts' ability to meet factors such as lighting and amenities and ensure equity and accessibility. Once the Company recruits site hosts and acquires signed agreements, the Company would install the charging stations and operate them through its contracted charging network provider.

The pros of this option for customers include greater equity and accessibility for public charging. By nature of this model, the utility can own and operate public charging stations in locations the private market may be hesitant to serve, benefiting customers in rural areas, areas with low EV adoption, and disadvantaged communities. In addition, this option provides the Commission with greater authority over equity, accessibility, affordability, and reliability of a public charging network as a utility-owned and operated Public DCFC network would be governed through regulation.

The con of this approach is the uncertainty associated with a rapidly changing market. Success would depend on a third-party charging network provider to operate and maintain the stations on the Company's behalf. With the rapidly changing landscape of network providers, technology, partnerships, market entrants, and consumer preferences, there are risks in relying on third parties for Company success. If the Company's third-party charging vendor is not successful with maintaining consistent, reliable operations, such has been the case in the private public charging market to

[55] See, e.g., Colorado allows utilities to amortize rebates over ten years and earn a return for rebates on home wiring, certain chargers, and IQ purchases. Similarly, New Mexico allows TEP rebates to be amortized over ten years. Maryland and Michigan allow EV charging infrastructure rebates to amortized over five years. New York supports utility-supplied EV make-ready infrastructure to be held as a regulatory asset and amortized over 15 years.

date and in the Xcel Energy's experience in Colorado thus far, it could result in a negative customer experience for drivers, additional costs, and a negative experience for site hosts.

d. DCFC Partnership[56]

An alternative program design that also involves utility ownership would be a Partnership-type approach like the initiative Xcel Energy is pursuing in its Wisconsin service territory.[57]

Through this model, the Company could establish mutually agreeable contract terms with potential partners that specify roles and responsibilities associated with owning and operating fast charging. The partnership model could include a variety of mutually agreeable arrangements, including an approach whereby customers would procure and/or construct DCFC sites that the Company would then purchase from the customer after completion at an agreed upon price. In this build-buy-transfer approach, the Company would own the charging infrastructure, including the EVSI and DCFC station, but the partner would be responsible for site operations, maintaining and operating the DCFC, customer experience operations and maintenance costs, and may collect charging station revenue.

The pros of this approach for customers or others who would partner with the Company are financial, in that the Company is a financial "partner" to help reduce costs.

The cons of this approach for customers may include the potential for additional administrative complexity for contract and site negotiations, as each site may have different and specific partnership needs compared to others. Depending on the number of partners and sites and the associated complexity of a partnership arrangement, this model may not be as scalable for supporting the expansion of public charging as others that are discussed.

[56] The terms "partner" and "partnership" are used to denote collaboration between independent actors and are not intended to mean a legally recognized partnership.
[57] *Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates,* Docket No. 4220-UR-126

6. *Feedback and Future Proposal to Support Public Fast Charging*

The Company looks forward to additional discussion on the topic of how it can best support public fast charging in its service territory. Based on the Company's experience with its Public Charging Pilot to date, and feedback received through the surveys discussed above and other input received, the Company believes there is customer and stakeholder interest in the Company providing EVSI for public fast charging consistent with its Public Charging Pilot, and in providing rebates for public chargers. Xcel Energy has seen success with providing EVSI for a variety of commercial charging needs in multiple jurisdictions, and with placing EV program rebates in a regulatory asset that earns a return equal to the weighted average cost of capital of the Company.

7. *Public Charging Infrastructure: Needs & Opportunities*

As discussed above, this year has seen important developments towards potentially standardizing aspects of the public fast charging market. Considering these developments, and in recognition of the Commission's request to do so,[58] the Company here provides an assessment of how it can best support the public fast charging market.

As part of its work to assess this market, the Company has outlined the current state of the public fast charging market, potential future market needs, existing programs that support the current market, and high-level descriptions of ways the Company could support the future market. In addition, and in order to assess how to best support this market in the future, the Company engaged with public fast charging providers and Fueling Minnesota, a trade group representing approximately 500 retail fueling providers across the state. This engagement has taken place through conversations and surveys, with the goal of better understanding how major public fast charging stakeholders plan to expand access to public charging in the Company's service territory, as well as how the Company can work with them to support that expansion.

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[58] *In the Matter of the Petition of Northern States Power Company for Approval of a Public Charging Network and Electric School Bus Pilot and Program Modifications*, Docket No. E002/M-22-432, ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS, Order Point 3.B. (Aug. 23, 2023)

Overall, as EV adoption in Minnesota accelerates, the Company is focused on supporting the expansion of affordable, convenient, and reliable EV charging infrastructure.

a. Charging Gaps and Future Charging Needs[59]

From 2015 to 2022, the public fast charging market in the Company's service territory grew at a 43 percent Cumulative Annual Growth Rate (CAGR). Table 7 below shows the year-over-year growth in DCFC ports in the Company's Minnesota service territory since 2012.

Table 7
Year Over Year Growth in Ports in the Company's MN Service Territory[60]

Year	Incremental DCFC Ports	Cumulative DCFC Ports	Year-over-year Cumulative DCFC Ports
2012	3	3	-
2013	3	6	100%
2014	2	8	33%
2015	3	11	38%
2016	8	19	73%
2017	0	19	0%
2018	2	21	11%
2019	32	53	152%
2020	34	87	64%
2021	23	110	26%
2022	64	174	58%
2023	40	214	23%

Despite this growth, it is being outpaced by EV adoption: EV growth in the state is outpacing total public charging installations growth, including L2 ports, by more than a factor of two.[61] Additionally, it is important to note that not only do not all drivers have access to charging at home, but one out of every three vehicle shoppers in the U.S. does not have access to home charging *or the ability to install a home charger if they*

[59] Provided in Compliance with Order Point 3.B of the Commission's August 23, 2023 Order in Docket Nos. E002/M-22-432.
[60] Alternative Fuels Data Center (Data as of August 2023)
[61] J.D. Power EV Index: Minnesota had 53 percent EV PARC growth vs. 20 percent weighted Avg Charger Growth from Jul '22 – July '23 – Confidential Information

needed to.[62] The lack of charging availability remains the top reason for not considering an EV.[63]

Charging station installation growth is only a part of the equation when it comes to supporting EV driver needs. Approximately 20 percent of EV owners who attempted to charge at a public location in 2023 were unable to do so.[64] The vast majority of no-charge visits are due to broken chargers, and lack of available chargers (chargers already in use) is becoming a more frequent problem.[65]

The high rate of EV adoption and the lack of accessible and reliable charging indicates gaps in charging infrastructure. The Company further assesses these gaps below.

The Company has outlined charging gaps and needs in its service territory by analyzing the level of public fast charging needed to support the growing number of EVs on the roads. The charging needs analysis reflects a forecast completed in partnership with Guidehouse as well as surveys of charging providers and Fueling Minnesota's members about their investment plans. The Company uses Guidehouse's charging needs forecast along with the survey data to assess the market's ability to meet the public's need for infrastructure, identify potential gaps, and inform utility program recommendations.

i. Guidehouse Forecasts

For this TEP, the Company worked with Guidehouse to model EV charging needs based on the same EV forecast scenarios modeled in LoadSEER for the Integrated Distribution Plan, based on the Company's 2022 Mid Case EV Adoption Scenario (see *Appendix A1: System Planning*).[66] The charging needs forecast shows over 1,400 public DCFC ports – amounting to approximately 335 MW of charging capacity – in the Company's Minnesota service territory in 2030. This is approximately 1,200 ports beyond what is currently installed in the Company's service territory as of August 2023.

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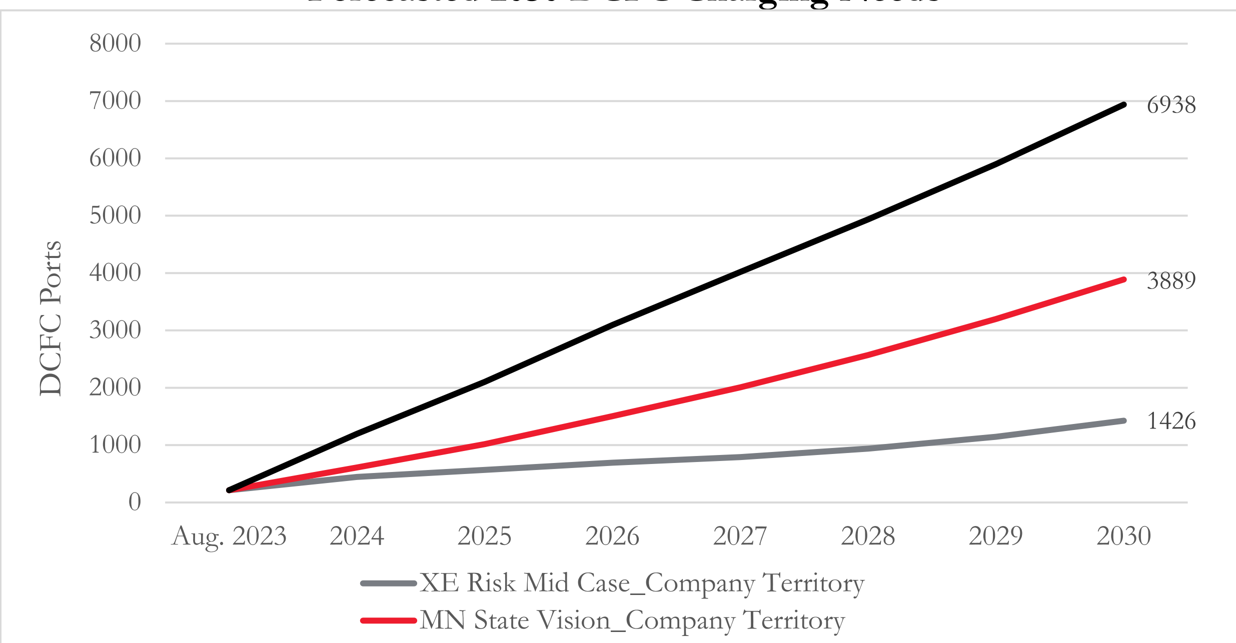
[62] J.D. Power 2023 U.S. Electric Vehicle Consideration (EVC) Study – Confidential information
[63] J.D. Power 2023 U.S. Electric Vehicle Consideration (EVC) Study – Confidential information
[64] J.D. Power 2023 U.S. Electric Vehicle Experience (EVX) Public Charging Study – Confidential information
[65] J.D. Power 2023 U.S. Electric Vehicle Experience (EVX) Public Charging Study – Confidential information
[66] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 3Bi.

Figure 2 below shows this forecasted charging need, as well as what will be needed to meet the public fast charging demand associated with the state's goal, both in the Company's service territory and statewide.[67] As can be seen in Figure 2, the number of DCFC ports needed in the Company's service territory to support the level of EV adoption consistent with the state achieving its 2030 EV adoption goal is more than 2.5 times the number of DCFC ports needed in the Company's territory under the Company's Mid-Case EV Adoption Scenario. To meet the DCFC charging needs for the state of Minnesota in total, a substantial number of additional charging ports will also be needed outside of the Company's service territory.

Figure 2
Forecasted 2030 DCFC Charging Needs



The need for additional public fast charging is not uniform across the Company's service territory. Figures 3 and 4 show the public fast charging needed by census tract in the Company's service territory, both statewide and for the Twin Cities metro area specifically. As shown, a material amount of the additional 1,200 public fast charging ports are needed in 978 census tracts within the Company's service territory to meet the demand for public fast charging in 2030. Specifically, to meet the charging needs

[67] The Minnesota Department of Transportation and the Minnesota Pollution Control Agency outlined a statewide vision for increasing EV use in 2019. The document targets a 20 percent by 2030 target for light duty ("LD") EVs. See: Accelerating Electric Vehicle Adoption: A Vision for Minnesota (mn.gov) and Minnesota's Electric Vehicle Infrastructure Plan. See: Electric Vehicle Infrastructure Plan | Let's Talk Transportation - MnDOT (state.mn.us)

of the Company's Mid-Case EV Adoption Scenario, 834 census tracts need up to 25 more DCFC ports in 2030 (average of 0.5 MW), 134 census tracts need between 26 and 49 more ports (average of 1.3MW), and 10 census tracts need more than 50 ports (average of 2.2MW).

Figure 3
Heat Map of 2030 Charging Needs by Census Tract in NSPM

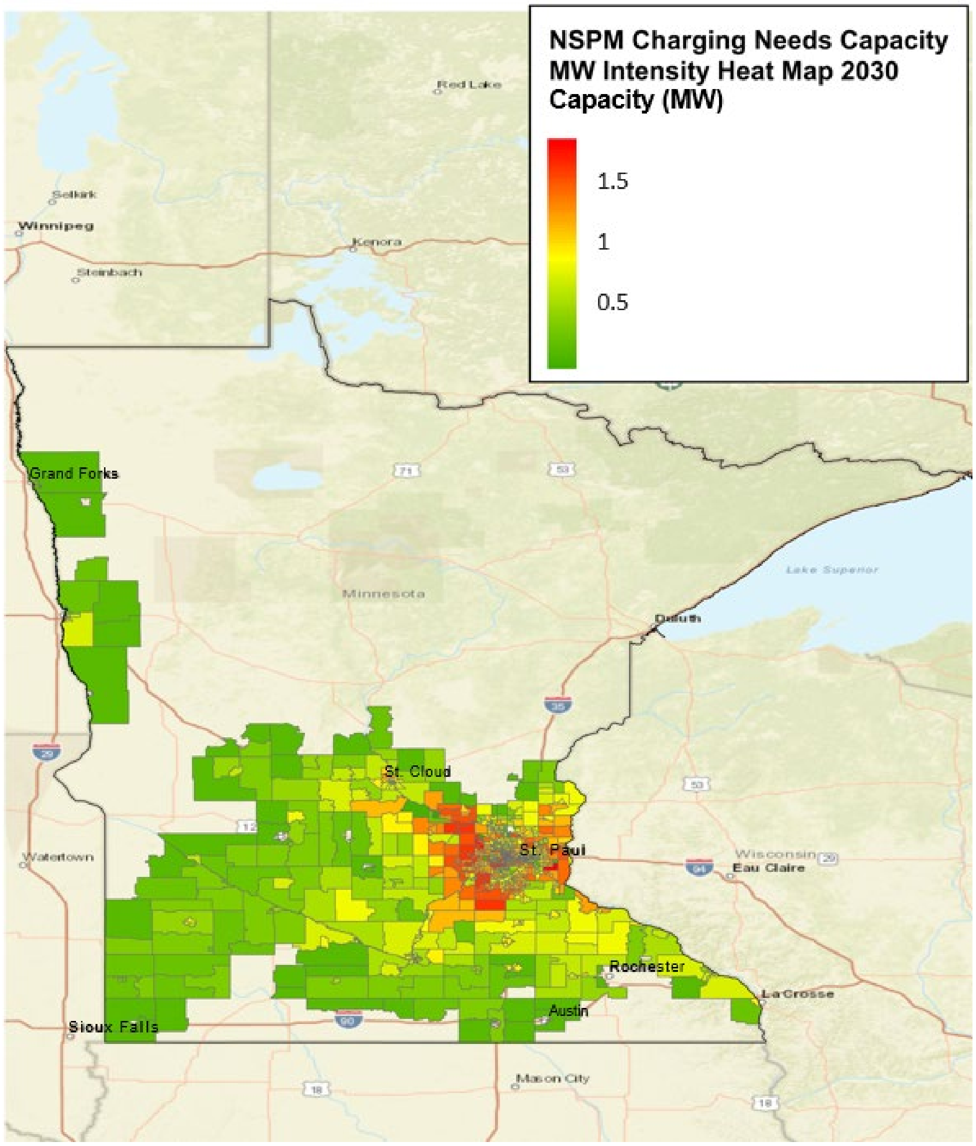
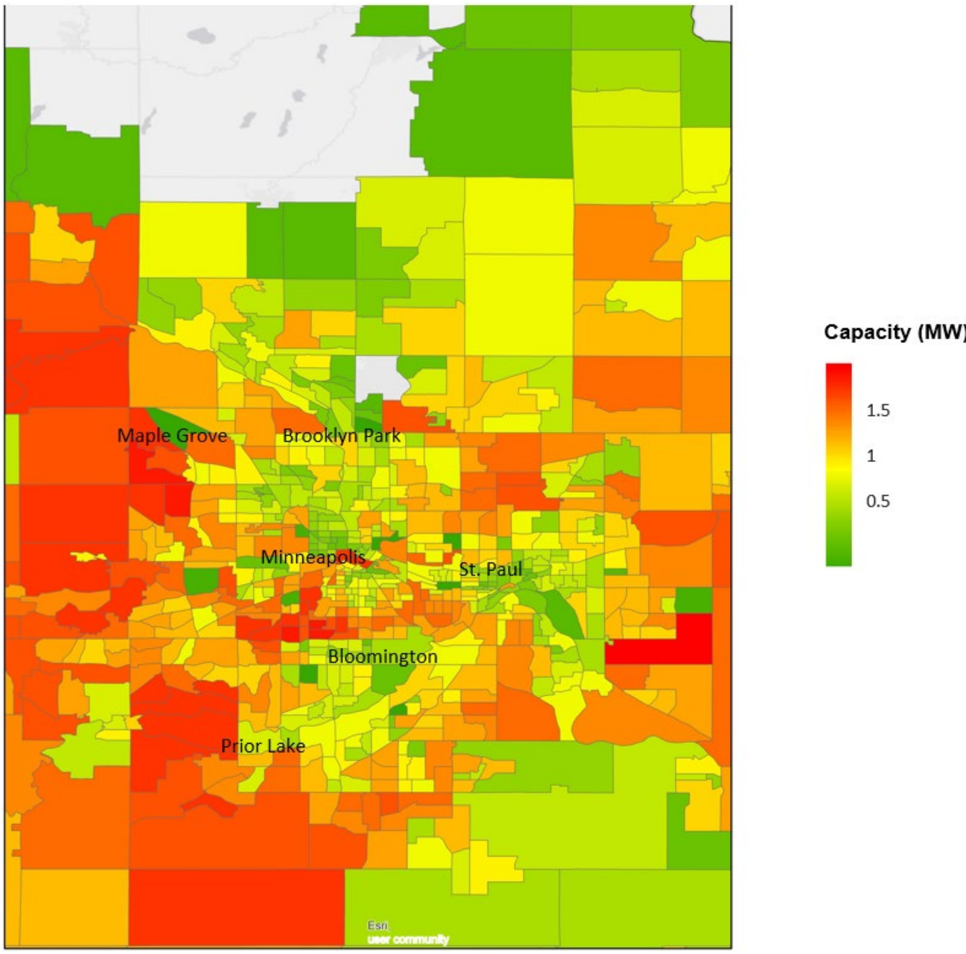


Figure 4
Heat Map of 2030 Charging Needs by Census Tract in NSPM – Twin Cities Metro Area



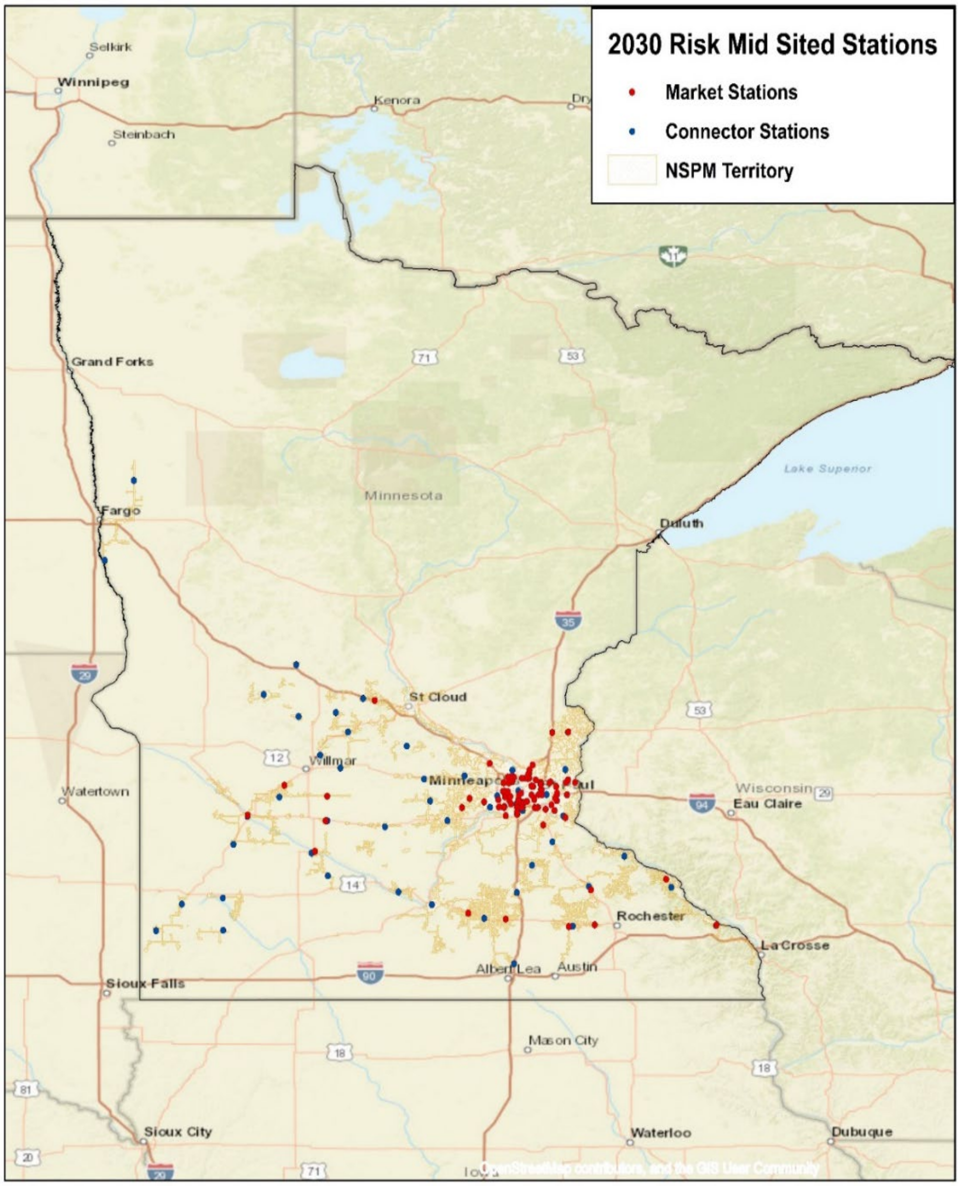
From this analysis, most of the public fast charging need in the Company's service territory is in and around the Twin Cities metro area. Additionally, although the capacity of charging needed is not uniform from census tract to census tract, public fast charging is needed throughout the Company's entire territory to support EV adoption associated with the Company's Mid-Case EV Adoption Scenario, including both rural and urban areas. The capacity of public fast charging needed to support the level of EV adoption consistent with the state's EV adoptions goals would be substantially greater than level of charging capacity indicated in Figures 3 and 4 above.

To complement the charging needs analysis above, Guidehouse conducted a siting analysis that uses a geospatial network optimization algorithm to estimate specific, geographically optimal locations (lat/long coordinates) for public fast charging infrastructure based on the Company's Mid-Case EV Adoption Scenario and the locations of existing public EV supply equipment (EVSE).

The purpose of this analysis is to identify "ideal" locations for the public fast charging needed at a much more granular level than census tracts. This analysis supports the expansion of the public fast charging market in the Company's service territory by identifying optimal locations for chargers based on traffic volume, navigation rules, maturity of the existing charging ecosystem, and expected EV penetration rates. Notably, this analysis does not take into consideration important real-world constraints, such as land availability, site development costs such as trenching, and distribution system capacity, that would impact the actual siting of public chargers.

Figure 5 below depicts the 139 sites that were identified as optimal locations for public charging infrastructure within the Company's service territory.

Figure 5
2030 Sited Stations



The siting analysis results in Figure 5 indicate both the locations and types of public fast charging installations that would be ideal to meet the needs of EV drivers in 2030 based on the Company's Mid-Case EV Adoption Scenario. Market stations, shown in red, are meant to provide fast charging at destinations within an urban setting. Connector stations, shown in blue, are meant to provide fast charging in rural communities or along major travel corridors to enable long distance travel. The amount (capacity) of fast charging needing to be installed at or around any of these locations to fulfill the forecasted charging demand varies by location; Figures 3 and 4 indicate the charging capacity needed in the areas of the sited stations shown in Figure 5.

ii. Public Charging Surveys

As a complement to the charging needs forecasts from Guidehouse, the Company surveyed third-party charging companies and other stakeholders in the public fast charging market in Minnesota to understand their plans to support the market and understand where additional need might exist. The surveys of Fueling Minnesota's members (retail fueling station operators) and public EV charging providers sought to better understand the level to which these stakeholders are pursuing public fast charging deployment in Minnesota.

Both retail fueling station operator and charging provider survey respondents reported financial concerns as top barriers to installing EV charging stations in the market, though charging providers' top financial concerns were different and less pronounced than retail fueling station owners. As would be expected, the ability to provide financial support dramatically increased the level of interest from fueling stations to providing public charging. When the Company asked retail fueling location operators about their level of interest in having public charging stations at their fueling locations in the future, 37 percent of those who responded said they were very interested. When asked about their level of interest if financial assistance was available, this number increased to 62 percent. This increased interest with greater availability of financial assistance makes sense given these respondents' significant concerns about the profitability and upfront costs of charging stations.

To assess the potential for and characteristics of potential public fast charging installations that the Company could help support in the future, we surveyed retail fueling station operators about their likelihood of investing in EV charging stations in the near to mid-term, and inquired with both survey groups about the capacity of fast chargers they are interested in installing. When the Company asked retail fueling station operators how likely they are to invest in EV charging stations in Minnesota over the next three to five years, 23 percent of those who responded indicated they are 'very likely' and 36 percent indicated they are 'somewhat likely' to do so. Survey responses indicate that the capacity of individual public fast chargers installed in the future is likely to greatly exceed the charger capacities installed to date through the Company's Public Charging Pilot, as 75 percent of the chargers installed to date with support from the Company's Public Charging Pilot have been under 50 kW. When the Company asked respondents about the charging station output levels for which they are interested, 57 percent were interested in installing DCFC stations over 350 kW, 47 percent were interested in between 150 kW and 350 kW, and 27 percent were unsure what power range they desired. The charging providers who responded indicated similar interest in power ranges over 350 kW and between 150 kW and 350kW.

The Company asked both retail fueling station operators and charging providers about which ZIP codes they are likely to invest in EV charging stations over the next three to five years. Fifty-three retail fueling station operators, representing over 118 unique locations, shared the ZIP codes they operate in and their likelihood to invest, shown below in Figures 6 and 7. Although given the same option to respond, no charging providers provided this information.

Figure 6
Retail Fueling Station Respondents: Likelihood of EV Charging Investment by ZIP Code Over the Next Three to Five Years, Statewide View

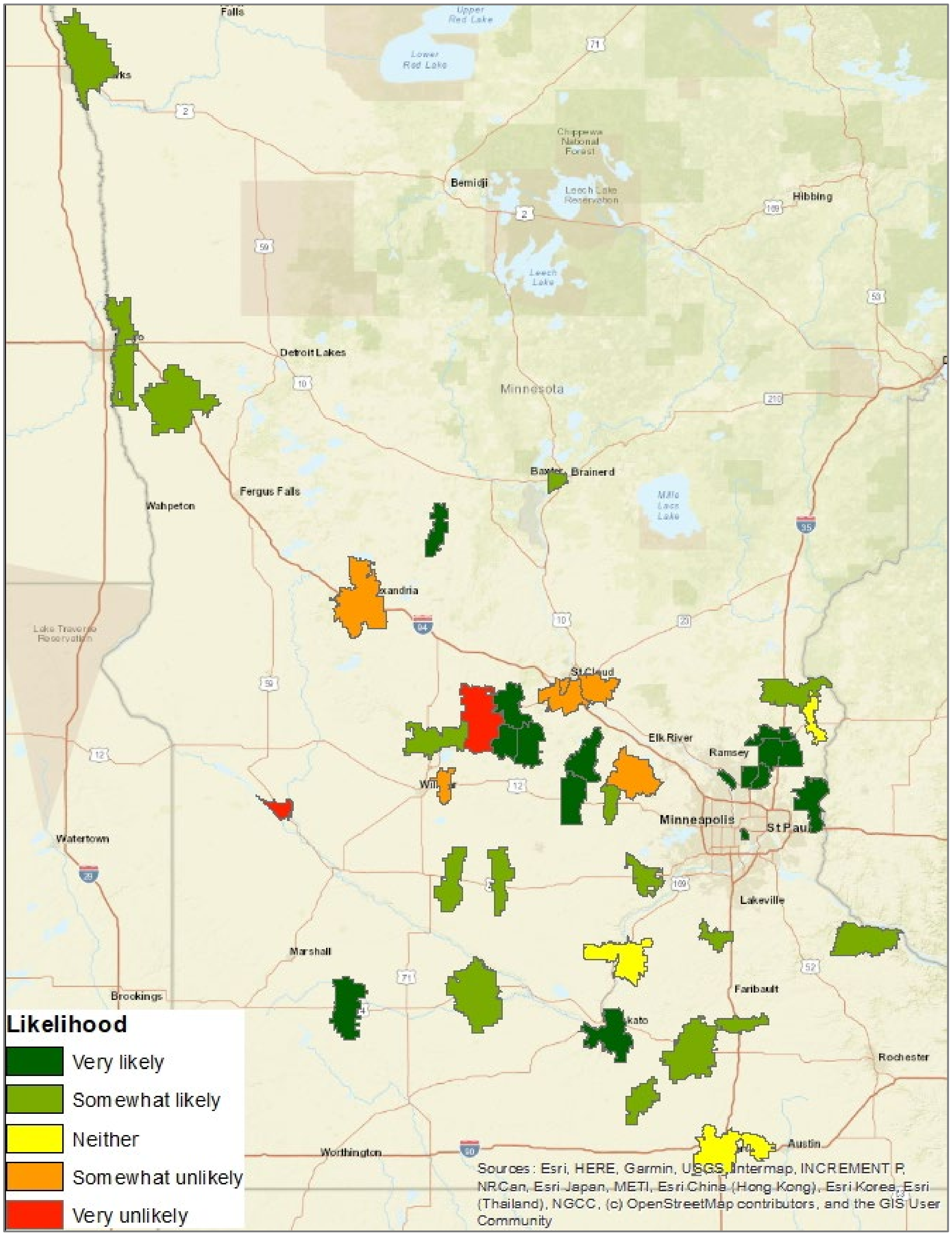
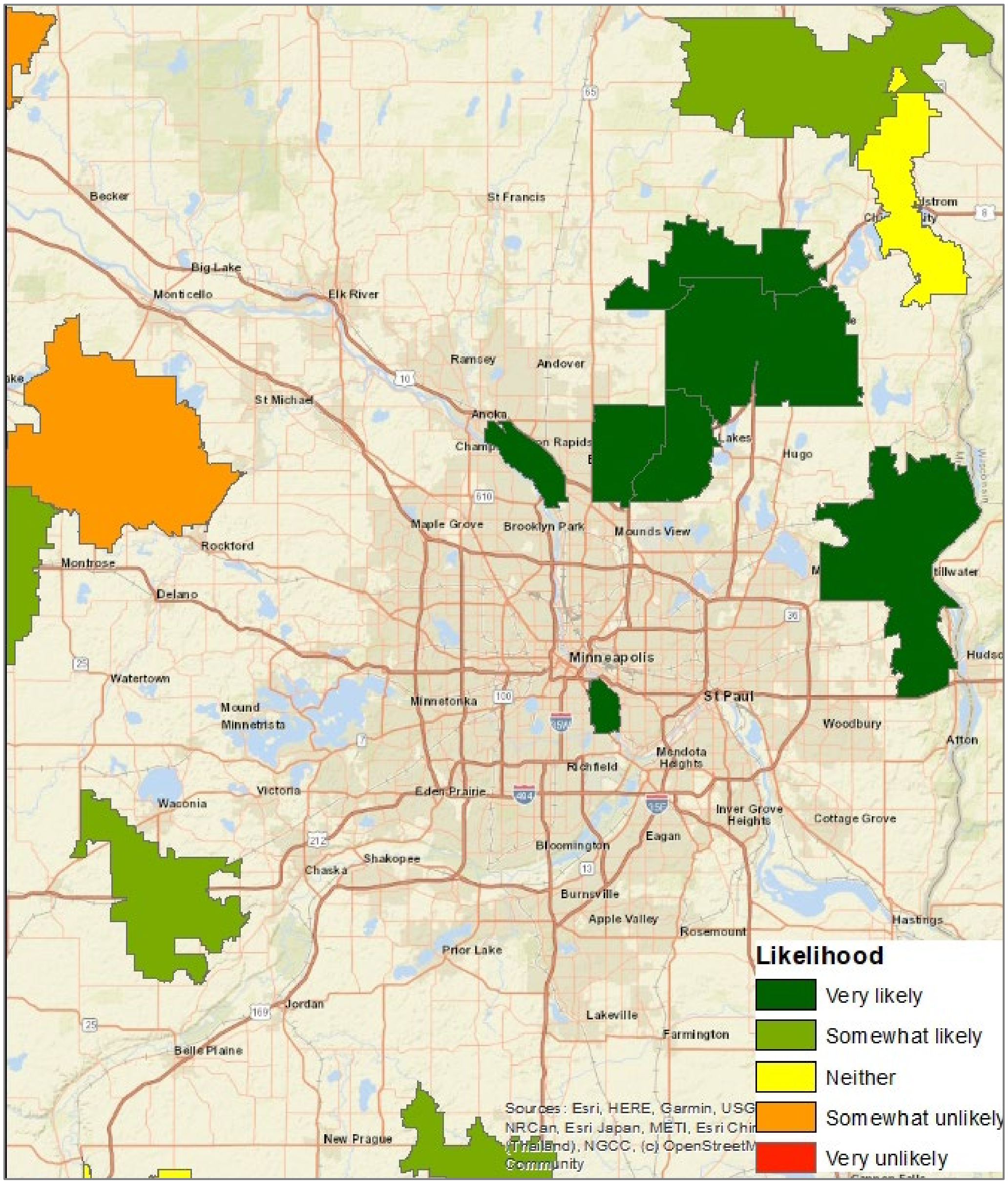


Figure 7
Retail Fueling Station Respondents: Likelihood of EV Charging Investment by ZIP Code Over the Next Three to Five Years, Twin Cities Metro Area View



Acknowledging that survey respondents that answered this question and provided ZIP codes represent a fraction of the retail fueling station market in the state, when combined with the charging needs analysis conducted by Guidehouse, the results nonetheless provide some insights on the general areas where retail fueling station operators' interest in installing new EV charging stations and charging needs overlap.

When comparing the areas, there is some overlap between interest from fueling station owner respondents in installing new charging stations and charging needs in the northeastern area of the Twin Cities metro area. There is moderate overlap between interest in installing new charging stations and charging needs in St. Cloud and in some areas between St. Cloud and Minneapolis.

In general, there appear to be gaps between interest from fueling station owner survey respondents in adding charging stations and charging needs in the western and southwestern areas of the Twin Cities metro area.

b. Current Offerings that Support Public Charging

The Company currently operates a Public Charging Pilot that provides make-ready EVSI to participating customers. This Pilot reduces upfront costs and technical barriers to installing publicly accessible charging stations.[68] The Pilot is also helping the Company understand how different variables, including TOU rates, impact charging behavior and the electrical grid.

As part of this Pilot, we now have 75 completed, in-service projects with an additional 53 projects moving through design and construction phases. Projects consist almost entirely of municipality sites (102 sites, 70 of which are HOURCAR Evie carshare sites) and auto dealerships (24 sites) across a broad geographic area in the Company's service territory. Two additional projects through the Public Charging Pilot consist of a public school district and an energy efficiency solutions provider. The Company has closed the pilot to incremental enrollment as it has reached its approved budget, and the Company is working on collecting data and learnings with the existing pool of projects to help inform future program proposals.

Additionally, the Company has been approved to install, own, and operate DCFC charging stations in Minnesota.[69] The Company is placing DCFC stations in locations not currently served by the existing market, mostly in the rural parts of the state outside of the Minneapolis-St. Paul area. This pilot focuses on addressing range anxiety, a primary barrier to EV adoption. The pilot also helps address the current public charging infrastructure gap in the Company's service territory, provide access to charging for those who cannot charge at home or at their business, and enable

[68] The Public Charging Pilot was approved by the Commission. Order Dated July 17, 2019 in Docket No. E002/M-18-643.
[69] *See* ORDER APPROVING PUBLIC CHARGING STATION PROPOSAL (April 27, 2022), Docket No. E002/M-20-745, Order Point 1

inter- and intra-community electric transportation. As discussed in our June 30, 2023 Supplement, the Company has recently decided to focus only on the projects where the Company has signed agreements. This includes seven individually owned sites.[70] The decision to limit the pilot to the projects with signed agreements was made due to higher forecasted costs caused by inflationary pressure along with recent market announcements on changes in technology.

D. Addressing Flexible Load, Metering Costs, Encouraging Managed Charging, and Optimizing EV Benefits for Grid and System Efficiency[71]

As noted, the Company currently offers a variety of programs, and we are proposing new and expanded programs in this TEP to further support the use of managed charging and reduce metering and infrastructure costs. Where applicable, these programs and proposals incentivize customers to align their EV charging load to take place during off-peak system hours, when there is low customer demand and generally, higher renewable energy production on the system.

E. Future Technologies

There are two key technologies that have garnered particular interest among the industry when it comes to furthering the optimization of EV load for grid and system benefit. One such technology, being V2G, and the second, being Advanced Metering Infrastructure (AMI). Both technologies can potentially support greater alignment of EV charging with periods of low customer demand and higher renewable energy production to improve grid management and overall system utilization and efficiency. We provide a discussion on each of these technologies, their potential capabilities, considerations, constraints, and timing for when the Company may test and/or deploy them.

- **Vehicle-to-Grid:** V2G refers to the ability of EVs enabled with bi-directional charging capabilities to be used as a source of power, potentially exporting power directly to the grid to help manage system needs. The Company proposes additional support for a V2G demonstration designed to increase the Company's understanding of this technology while accelerating opportunities for market adoption to benefit both customers and the grid.

[70] *See* our June 30, 2023 Supplement in Docket Nos. E002/M-15-111, et. al.
[71] Provided in Compliance with Order Point F.2.c of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.

V2G has the potential to provide grid services that indirectly benefit all customers by providing additional capacity at times of system peak, relieving distribution constraints at the feeder level, and helping with the integration of high penetrations of renewables. However, significant challenges must be overcome before the technology becomes scalable. These include a lack of system interoperability, concerns with vehicle's battery degradation, proper valuation of this new resource, and grid interconnection. The Company has been closely following V2G development for over a decade. In 2008, the Company participated in one of the first V2G field pilots conducted by the National Renewable Energy Laboratory using a 2008 Ford Escape plug-in hybrid EV. Since then, EV technology has significantly advanced, but V2G has made what might be considered only incremental improvements. To help determine the current state of V2G technology, the Company commissioned a research paper on V2X (vehicle-to-home, -building, and -grid). The paper discusses the potential of this technology along with the challenges that must be overcome before widespread adoption can occur. A copy of this paper has been included with this filing as Appendix H3.

As a proposal under this TEP, the Company's demonstration will focus on using electric school buses, which, due to their large battery capacity and regular driving schedules, have seen more rapid adoption of V2G than other types of electric vehicles. Through the demonstration the Company will provide EVSI and rebates for bi-directional EV chargers to school districts and/or other electric school bus operators. By agreeing to be part of the demonstration the school district/electric school bus operator will agree to allow the Company to discharge power from the vehicle in response to grid conditions. Minimum state of battery charge, when discharge events could occur, and duration of events will be conveyed to participating customers. Recognizing that the primary purpose for an electric school bus is transportation, use of the electric school bus for V2G purposes will always be contingent upon the bus's availability and customers will have the ability to "opt-out" should a scheduled event interfere with use of the bus for transportation purposes. The Company anticipates customer recruitment and procurement would begin in 2024 following approval of the additional support proposed in this filing, and the first V2G operations could occur beginning in 2026. V2G sites will need to follow the Company's interconnection requirements for sending power onto the grid to ensure the safety and reliability of grid operations. Distribution upgrades could be required to accommodate electric school bus discharging based on the results of the interconnection study. The Company intends V2G testing for various events along with monitoring performance and evaluating impacts to the participants and the buses will continue for a period of two years. The Company plans to issue a report providing a summary of demonstration results upon conclusion of the demonstration.

- **Advanced Metering Infrastructure:** As discussed in Appendices B1 and B3 of the IDP, AMI is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables secure two-way communication between Xcel Energy's business and data systems and customer meters. Meters being deployed as part of the Company's AMI rollout include Distributed Intelligence (DI) capabilities, which can potentially enable EV Detection.

  EV Detection, when adequately developed, can provide the Company with insights into where EVs are located and charging patterns of customers. This information will be leveraged to support system planning, load balancing, and infrastructure upgrade efforts based on awareness of EVs being added to a customer's load profile. This grid-facing use case will also enable the Company to become aware and proactively respond to possible service quality issues and encourage customers with EVs to participate in managed charging programs.

  By detecting EV load through AMI and DI capabilities, the Company can potentially create detailed load profiles for EV charging customers by separating the EV-related load from other household loads, providing a more granular understanding of energy usage.

F. Improvements to Advisory Services Available to Customers

As the Company continues to offer Advisory Services, we are observing which activities are most effective at creating customer awareness for EVs and our managed charging programs. As described in Section III.E below, we are proposing expanded Residential Advisory Services to build upon our efforts, enhance our services, and support our residential managed charging programs.

G. Streamlining and Improving the Company's Internal Processes[72]

The Company is focused on two primary initiatives to streamline and improve its internal processes related to EV charging infrastructure installation outside of its existing Commercial EV Pilots.

First, the Company has created a dedicated team of EV-focused Distribution engineers that is working to understand how, when, and where the accelerating onset of EV load will likely impact the Company's electric distribution networks. This team tracks fleet and public charging capacity and integrates internal and external data sources (e.g., through Guidehouse's localized demand forecasting results) to forecast which feeders EV load is likely to impact in the near future. A goal of this team's work is to identify the most cost-effective options for integrating EV load across the system at the feeder level.

Second, the Company plans to conduct additional research and consumer insights to understand EV parties' interconnection pain points outside of the Company's EV programs. The Company plans to use these insights to identify potential solutions that could streamline EV infrastructure deployment (such as dedicated navigators).

The Company is already implementing various initiatives to streamline and improve its Commercial EV Pilot projects as documented in its 2023 Annual EV Reporting, including realigning equipment procurement processes to ensure equipment is ready when customers need it; implementing monthly project and budget audit reporting; and automating workflow processes to enhance the customer experience. For greater information about our improvement processes, please see our June 30, 2023 Supplement to our 2023 EV Annual Report.[73]

III. NEW PROGRAM PROPOSALS & BUDGETS

The Company seeks approval of five proposals to introduce to the market in 2024. These five proposals are:

- Expansion plan for the EV Subscription Service Pilot,
- Home Wiring Rebate program to help reduce upfront charging infrastructure costs and encourage managed charging,

[72] Provided in compliance with Order Point 4.E of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432
[73] Submitted in Docket No. E002/M-15-111. The discussion of our process improvement process begins on Page 4.

- Electric School Bus support to facilitate V2G demonstrations,
- Expanded Residential Advisory Services, and
- Bridge funding for both the Fleet EV Service and Public Charging Pilots to continue supporting important commercial electrification projects.

In this filing we are also proposing additional spending on information technology (IT) to support these proposals as well as our existing EV efforts. Table 8, below, summarizes the total budget for these initiatives, while each proposal is discussed in more detail in the following subsections. The Company notes that none of the budgets listed in Table 8 are included in rates pursuant to the Company's Multi Year Rate Plan (MYRP).

Table 8
Total 2023 TEP Program Proposal Budget
($ Millions)

	2024	2025	2026	2027	Total
TEP Proposal Totals					
Total Operations and Maintenance (O&M) Costs	$3.8	$5.6	$3.5	$4.5	**$17.5**
Total Capital Costs	$7.5	$12.6	$2.8	$3.9	**$26.9**
Total Costs	$11.3	$18.3	$6.3	$8.4	**$44.5**
EVAAH – Subscription[74]					
Participants	605	1,082	1,383	2,040	**5,109**
O&M Costs	$0.3	$0.5	$0.7	$1.1	**$2.6**
Capital Costs	$0.5	$1.0	$1.3	$1.9	**$4.6**
EV Home Wiring Program					
Participants	756	1,352	1,902	2,652	**6,662**
O&M Costs	$0.2	$0.5	$0.7	$1.0	**$2.4**
Capital Costs	$0.5	$0.9	$1.3	$1.9	**$4.6**
Residential Advisory Services					
O&M Costs	$1.2	$1.7	$1.9	$2.0	**$6.8**
Electric School Bus Demo					
Participants	0	0	2	0	**2**

[74] EVAAH – Subscription is a program that is paid for by participants, similar to its EVAAH – Pay-As-You-Go counterpart, under the EVAAH program umbrella.

	2024	2025	2026	2027	Total
O&M Costs	$0.0	$0.2	$0.3	$0.3	**$0.8**
Capital Costs	$0.0	$0.0	$0.2	$0.2	**$0.5**
Commercial EV Pilot Bridge					
Fleet Ports	29	42	-	-	**71**
Public Charging Ports	326	392	-	-	**718**
O&M Costs	$2.1	$2.8	$0.0	$0.0	**$4.9**
Capital Costs	$6.5	$10.4	$0.0	$0.0	**$17.2**
Information Technology					
O&M Costs	$0.2	$0.3	$0.1	$0.2	**$0.9**
Capital Costs	$0.7	$1.2	$0.2	$0.3	**$2.4**

A. EV Subscription Service Pilot Expansion

The Company launched its Residential EV Subscription Service Pilot in February of 2020. The pilot allows customers to charge off-peak for a preset monthly fee, encouraging off-peak charging and offering customers certainty in monthly charging costs. The Pilot provided customers with all the services of EVAAH, but instead of a three-part TOU rate, they are charged a straight-forward monthly subscription fee that makes the cost of charging an EV easy to understand and consistent from month to month. The Pilot has been extremely successful, despite being confronted with challenges having initiated at the outset of the COVID-19 Pandemic. The Company has observed, like with EVAAH, high customer satisfaction marks in the 90+ percent range, even higher than historically experienced in EVAAH. Further, the pilot has also been effective at encouraging off-peak charging, with approximately 96 percent of all charging activity occurring off-peak. For more information on the Pilot's learnings and evaluation, please see Appendix H4.

Based on the results of the EV Subscription Service Pilot, we propose expanding the Pilot as a permanent offering as an option under EV Accelerate At Home, as EV Accelerate At Home – Subscription. We provide more details about this proposal below.

1. *Program and Rate Design*

As described, we propose to expand and merge the EV Subscription Pilot as an option under EVAAH. This change will simplify our programs for residential customers, since we will have one program offering called EV Accelerate At Home. Customers participating in EVAAH could then either sign up for the "Pay-As-You-Go" option, in which customer takes service under the existing three-period Residential TOU rate, or the "Subscription" option in which customers take service under an updated flat monthly rate for off-peak charging.

To expand the Pilot as a permanent offering, the Company proposes changes to the program design based on its learnings and evaluation. The changes are listed below and will ultimately enhance the program and provide benefits and more flexibility to customers.

- *Refresh the Subscription pricing* to align with updated EVAAH equipment and service costs recently proposed in Docket No. E002/M-19-559[75] as well as an updated assumption for assumed monthly energy usage.
- *Update the underlying energy rates* used to calculate the monthly flat fee to leverage the three-period residential TOU rates used within EVAAH. This will align the rates across all options under EVAAH.
- *Introduce a monthly consumption cap* of 1,000 kWh per month. In analysis of the EV Subscription Service Pilot, we found that 95 percent of all monthly charging sessions was 1,000 kWh or less. By setting a cap of 1,000 kWh per month, we can lower the assumed energy rate, and by extension the monthly flat fee, to better align with most participants' actual charging needs. This also serves to ensure customers are not able to charge multiple EVs with one charger using the fixed monthly price.
- *Introduce a Bring-Your-Own-Charger (BYOC) option*, in alignment with the Company's EVAAH BYOC option as proposed in Docket No. E002/M-19-559.[76]
- *Update the Customer Service Agreement (CSA)*, to reflect the changes outlined above. A singular CSA will be implemented for EVAAH and apply to participants within both Pay-As-You-Go and Subscription options.

EVAAH Subscription participants will continue to see the flat monthly fee on their monthly energy bill. Enrollment term for EVAAH Subscription (Bundled) will remain at 10 years, in alignment with EVAAH Pay-As-You-Go (Bundled). Participants will be able to transition to EVAAH – Pay-As-You-Go from EVAAH – Subscription, and vice versa, as they prefer based on their charging needs.

[75] *See* our Petition filed on September 12, 2023.
[76] *Ibid.*

The workpapers for the EVAAH – Subscription pricing and rate design can be found in Appendix H5.

2. Transition Plan for Existing Pilot Participants

Similar to how we transitioned the EV Service Pilot to EV Accelerate At Home, we will provide existing EV Subscription Service Pilot customers notice that the Pilot is ending and communicate the options that they have available to them. As was set forth in the CSA for the Pilot, participating customers may either terminate their participation from the Pilot or transition to the expanded EV Accelerate At Home – Subscription or Pay-As-You-Go options. Customers that elect to end their participation and had been participating under the Pilot's bundled option have two options.[77] They can either purchase the installed EVSE for a cost equal to the undepreciated balance of the equipment or have the Company remove the EVSE at no cost to them. The Company will handle this transition and all customer interactions through direct email and by phone as needed and will commence this transition plan upon the date that the Commission approves this expansion proposal.

3. Operations and Customer Experience

Enrollment within EVAAH – Subscription will be incorporated into the existing digital enrollment process for EVAAH. During the enrollment flow, customers will be prompted to select how they wish to participate by either choosing to take a charger from the Company or bring their own. They also select how they want to pay for their energy, either on a per-kWh basis (Pay-As-You-Go) or on a flat off-peak monthly fee basis (Subscription). In both options, customers can also opt-in to voluntary renewable energy programs for their EV charging.

Like in EVAAH – Pay-As-You-Go, if customers are already on a whole-home TOU rate and/or have solar panels onsite and participate in net metering, they will be directed to the Voluntary EVAAH option and to the applicable rate and renewable energy programs on our website.

The EVAAH – Subscription tariff, CSA, program website and enrollment experience will be updated to reflect the new option, pricing, and terms. IT development work will be needed to modify the enrollment experience and to automate the necessary

[77] These terms are laid out in Section 4.5 of the Pilot CSA, as filed with our October 17, 2019 Compliance Filing in Docket No. E002/M-19-186.

integrations of internal systems used for customer record management and billing. As the subscription service CSA is included in our electric rate books, we show both the proposed tariff and CSA changes together as Appendix H6.

4. *Eligibility*

EVAAH – Subscription participants will be subject to the same eligibility requirements that exist today for the EVAAAH program, including but not limited to:

- Not on Residential EV Service Rate
- Not participate in the Residential Time-of-Day Service Rate.
- Not participate in the EVAAH – Pay-As-You-Go option. If desired, customers can unenroll from Pay-As-You-Go and enroll in Subscription.
- Not currently taking service on the TOU Rate Design Pilot rates.
- Not participate in the Company's Net Metering tariffs.

5. *Reporting Requirements*[78]

The Company plans to carry forward most of the annual reporting requirements already established by the Commission for the EV Subscription Service Pilot.[79] Specifically, the Company is proposing to provide the following information annually.

- Participation information:
    - number of participants
    - number selecting each type of equipment
    - number choosing Windsource or another renewable energy rate offering and the number choosing standard rates
- kWh consumption details on a per month basis, including:
    - kWh consumed in the on-peak period
    - kWh consumed in the off-peak period
    - comparison of actual consumption to estimated amounts
    - highest and lowest usage customer in each month
- Costs and revenues associated with each service option.
- Insights drawn from customer experience and program performance under the Company's safety and reliability standards.
- Any problems encountered connecting to the homeowner's wireless internet connection.

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[78] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO F

[79] As established in Order Point 7 of the Commission's October 7, 2019 ORDER APPROVING PILOT WITH MODIFICATIONS, AND SETTING REPORTING REQUIREMENTS in Docket No. E002/M-19-186.

6. *Participation, Costs, and Accounting Treatment*

As part of its annual reporting, the Company will monitor the participation level of the EV Accelerate At Home – Subscription option, compared to its Pay-As-You-Go counterpart. At this time, the Company projects that the Subscription option will garner considerable interest in the coming years given the success of the Pilot, and we are forecasting upwards of 3,500 participants by 2027. We estimate that 44 percent of all residential premises with NSPM territory are located within an EJ area. The Company did not previously track participation within the Subscription Pilot among customers located in EJ areas. As such, we apply the same percentage here, estimating that 44 percent of subscription participants will be in EJ areas, with the plan to continue to assess that participation rate after program launch.

As part of the expansion, we propose keeping the accounting treatment for the EVAAH – Subscription option essentially unchanged from what it was under the Pilot. The purchase and installation of EV charging equipment will be capitalized as an Electric Distribution asset to FERC Account 101, Plant in Service in plant account 370 (Meters). The EVAAH – Subscription bundled service customer charge will be designed to recover the carrying cost for the assets for the duration of customer participation. The Company also requests that the capitalized costs be allowed in rate base and receive a return on investment. The bundled customer charge, and the BYOC option customer charge, as applicable, are also designed to recover the costs for customer accounting and services, infrastructure maintenance, and data services.

B. Home Wiring Rebate Program

One of the largest upfront cost barriers to installing a Level 2 charging station in a home is the installation of a dedicated 240-volt circuit, which is required per electrical code. Electricians installing home wiring for Minnesota EVAAH participants in 2022 and 2023 reported an average of approximately $880 per installation, with actual costs varying by site, and $5,000 being the highest cost for a single project. When charger and charger installation costs are added to home wiring costs, we estimate the total average cost to install a networked Level 2 charger is approximately $1,800.

The Home Wiring Rebate Program (Rebate Program) is designed to encourage EV adoption and participation in managed charging programs by helping residential customers overcome this infrastructure cost burden and at the same time garnering their participation in a managed charging program as a condition of receiving the rebate. For customers living in Disproportionately Impacted Communities, environmental justice areas of concern, or that have previously or currently participated in energy assistance programs, we are proposing an enhanced rebate amount that covers a higher percentage of the average installation cost.

Xcel Energy has experience offering and operating such a program, having launched a similar rebate program in Colorado in August of 2021 which has been successful in assisting residential customers in overcoming the initial cost barrier to installing residential EV charging infrastructure and increasing access to managed charging programs. Rebate amounts in Colorado are similar to those proposed in this TEP, with a $500 "Market-Rate" rebate and $1,300 "Enhanced" rebates. As of August 1, 2023, in Colorado PSCo has administered 2,702 Market-Rate rebates and 141 Enhanced rebates for Income-Qualified customers.[80] All market-rate customers who received a rebate have enrolled and are participating in a managed charging offering.[81]

The following sections describe our Home Wiring Rebate Program proposal in more detail, which has incorporated valuable operational learnings and insights from our Colorado offering.

1. *Program and Rate Design*

We propose that the Home Wiring Rebate Program will provide a one-time Market rebate payment of $500 to residential customers and a $1,200 Enhanced rebate to customers who meet one of the following equity criteria:

- Premise is located within a Disproportionately Impacted Community (DIC), as defined and published by the White House Council on Environmental Quality's Justice40 Initiative;[82]
- Premise is located within an EJ Area, as defined and published by the Minnesota Pollution Control Agency;[83]
- Current or previous participant (within the last 5 years) in the Weatherization Assistance Program, Affordable Housing Rebate Program, or Minnesota's Low-Income Renter Classification

[80] Public Service Company of Colorado's 2021-2023 Transportation Electrification Plan Semi-Annual Report, Proceeding No. 20A-0204E, October 3, 2023
[81] Under the program terms in Colorado, income qualified customers may opt out of the managed charging participation requirement.
[82] Methodology & data - Climate & Economic Justice Screening Tool (geoplatform.gov)
[83] Understanding environmental justice in Minnesota (arcgis.com)

Customers can also enroll in one of the EVAAH options if they so choose, but participation in EVAAH is not required. Customers enrolling in the Bundled EVAAH offerings, in which a charger is provided by the Company (i.e., not BYOC), are eligible to receive up to $500 towards home wiring costs, based on actual wiring costs incurred. To focus on and address high equipment and installation costs among disproportionately impacted populations, Enhanced rebate recipients who also participate in the Bundled EVAAH offering are eligible to receive the full $1,200 rebate amount to cover charging station costs included in the monthly service fee. In other words, any unused portion of the $1,200 can be used to help offset the ongoing monthly costs of EVAAH. See AppendixH7 for an overview of the eligibility requirements for each rebate amount.

Rebate recipients who do not take an EVSE from the Company (i.e., those enrolling in EVAAH via the BYOC option and/or also enroll and participate in Optimize Your Charge) are also eligible for the $500 Market or $1,200 Enhanced rebate, which can cover home wiring costs, charger costs, or both. Market rebate participants only receive the full $500 if their home wiring and charging equipment costs exceed that amount.

Qualifying expenses include permitting, materials, installation and electrical work completed by a licensed electrician to install a 240-volt circuit to support a Level 2 charger. The cost of purchasing Level 2 chargers also qualify for the rebate.

2. *Operations and Customer Experience*

Customers can apply for the rebate via a digital enrollment process or through their EVAAH electrician, if they are participating in EVAAH Pay-As-You-Go or EVAAH Subscription, at the time of installation.

Customers may choose the way they receive their rebate, including:

- **At time of installation:** For customers who are also enrolling in EVAAH Pay-As-You-Go or EVAAH Subscription and choose to have their Company-contracted electrician also install home wiring, they can receive the rebate as a direct discount on the total installation cost at the time of installation.
- **Bill credit:** Customer receives a one-time credit on their energy bill.
- **ACH payment:** Customer receives a one-time payment to their bank account.
- **Rebate check:** Customer receives a one-time check mailed to their premise.

To aid in understanding the Home Wiring Rebate Program as it relates to the broader set of our residential programs, we provide Appendix H8, which provides a visual representation of how a residential customer may navigate and enroll in our programs with the options available to them.

3. *Eligibility*

Customers must meet basic eligibility requirements outlined below to participate in the Home Wiring Rebate Program. Upon enrollment, customers will agree to a Customer Service Agreement. The agreement will further outline eligibility and terms and conditions that a participant must adhere to throughout their participation.

Eligibility requirements include:

- Own or rent a single-family home, townhouse, or duplex as defined within the CSA.[84]
- Own or lease an EV, or plan to own or lease an EV in the near future.
- Have an active Minnesota Xcel Energy account that receives electric service.
- Enroll and participate in a managed charging program for at least one year. To fulfill this requirement, customers can enroll in Residential EV Service Rate[85], EVAAH – Pay-As-You-Go[86], EVAAH Voluntary[87], EVAAH – Subscription[88], or Optimize Your Charge. Recipients of the Enhanced Rebate may unenroll any time, including before the first year is complete.
- Demonstrate the charging equipment that relies on the 240-volt circuit for which the customer seeks the rebate draws 100 amps or less.
- Demonstrate that a licensed electrician performed the work to install the 240-volt circuit.
- Demonstrate and provide invoices that are dated on or after the launch of the program for labor and materials to install a 240-volt circuit.
- Install an Eligible EV Charger, as defined with the Customer Service Terms and Conditions

[84] If the participant is renting, they must receive permission from the property owner.
[85] Rate Code A08.
[86] Rate Codes A80 and A79
[87] Rate Code A76
[88] Rate Codes A82 and A84

4. *Reporting Requirements*[89]

We propose to add the following reporting requirements to our Annual EV Reporting:

- Number of Market rebates administered.
- Number of Enhanced rebates administered.
- Total number of all rebates administered.
- Total value of Market rebates administered.
- Total value of Enhanced rebates administered, and percent of the total value of all rebates administered.
- Percentage of rebate recipients located in an Environmental Justice Area of Concern (EJ area)
- Total value of all rebates administered.
- Average cost and discussion of home wiring installations.
- Program expenditures.

5. *Participation, Costs, and Accounting Treatment*

See Table 9, below, for participation and budget estimates for the Home Wiring Rebate Program. Based on program participation forecasts, we currently anticipate that approximately 44 percent of the rebate-specific budget will be used to administer Enhanced rebates, which are targeted to support customers in disadvantaged communities and EJ areas.[90]

Table 9
Home Wiring Rebate Program Participation and Budget
($ in Millions)[91]

	2024	2025	2026	2027	Total
Participation					
Market rebates	643	1,149	1,617	2,254	5,663
Enhanced rebates	113	203	285	398	999

[89] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5F.
[90] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5H.
[91] Table may not sum to totals due to rounding.

	2024	2025	2026	2027	Total
O&M Costs					
Charging Equipment Maintenance	$0.0	$0.1	$0.1	$0.2	$0.4
Program Administration	$0.2	$0.4	$0.5	$0.7	$1.8
IT	$0.0	$0.0	$0.1	$0.1	$0.2
Total Annual O&M	**$0.2**	**$0.4**	**$0.7**	**$1.0**	**$2.4**
Capital Costs					
Rebates	$0.5	$0.8	$1.2	$1.7	$4.2
IT	$0.0	$0.1	$0.1	$0.2	$0.4
Total Annual Capital	**$0.5**	**$0.9**	**$1.3**	**$1.9**	**$4.6**

For the Home Wiring Rebate Program, we request that the rebate expenses administered be placed in a regulatory asset and earn a return equal to the Company's weighted average cost of capital (WACC). Without the ability to spread out the rebate cost over the lifetime, the Company does not believe it would be feasible to scale this program.

C. Electric School Bus Demonstration[92]

In its decision accepting the withdrawal of our Clean Transportation Portfolio proposal, the Commission required the Company to include a proposal to support Electric School Buses as a part of this TEP.[93] In Compliance with that requirement, the Company brings forward a proposal for supporting the previously approved electric school bus V2G demonstration, and a discussion of future opportunities to support electric school bus deployment. In this section, we describe our proposal, its objectives and key learnings, reporting requirements, and coordination with the Department.[94]

The Company proposes to support a demonstration to begin to study and address barriers to school bus electrification, school bus bi-directional connection to the grid, and to better understand the costs and benefits of electric school buses as grid resources. Through this demonstration, the Company proposes to partner with the

[92] Provided in compliance with Order Point 4.D of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.
[93] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Points 3A, 4D, and 4F.
[94] Coordinating with the Department is a required by Order Point 4F of the Commission August 23, 2023 Order in Docket No. E002/M-22-432.

Department on its Electric School Bus Deployment Program, to support two V2G capable installations on sites of entities, school districts or school bus owners and operators, willing to participate in the demonstration to inform pathways of using V2G electric school buses in the future as demand response, distributed energy resources (DER) for grid resiliency and reliability resources.

As noted previously, the Company intends to file a supplement to this TEP in 2024. That supplement may include an expanded school bus offering when we are able to align our offerings more closely with the Department's school bus funding approach.

Order Point No. 16 in the Commission's February 1, 2019, Order in Docket No. E999/CI-17-879 requires utilities to include a discussion of specific topics in any future EV pilot proposal. Many of these topics are discussed throughout the rest of this section, but for ease of review, we provide as Appendix H9 a matrix of the topics with a brief discussion of each.

1. Program Design

The Company proposes to provide EVSI services, bi-directional capable EVSE, and related distribution interconnection infrastructure to two school bus operator participants at no cost. The Company will own and operate the distribution and EVSI equipment, similar to how it operates its Fleet EV Service Pilot today and intends to provide a rebate to the participants to defray the cost of the V2G-capable EVSE. Each participant and new service installed through the demonstration will be required to take service under the Fleet EV Service Pilot tariff, with an addendum to the CSA addressing V2G demonstration terms.[95]

This demonstration seeks to help eliminate barriers to electric school bus adoption and study the costs of service and potential grid benefits of electric buses to be used as a grid resource when not being driven. To the extent possible, the selection process for demonstration participants will give priority to bus operators and school districts that serve low-income, BIPOC, and rural communities.

The demonstration's primary objectives are:

[95] Rate Codes A87, A88, and A89.

- **Facilitate electric school bus V2G demonstrations approved in the Load Flexibility Plan**[96] to measure and verify effects of V2G on the distribution system and learn how to operate and manage the distribution system with V2G technology.
- **Reduce upfront charging infrastructure costs for school districts and school bus operators** to adopt and utilize electric school buses and associated charging infrastructure, which reduces carbon emissions benefiting not only the students but all state residents with cleaner air.
- **Advance the adoption of electric school buses to help meet the State's carbon reduction goals** while addressing a market segment that faces significant barriers to EV adoption.
- **Focus on low-income, BIPOC, and rural students** who are disproportionately impacted by diesel emissions and air pollution by prioritizing school districts in low-income, BIPOC, and/or rural communities.
- **Increase awareness and education** around electric school bus technology and capabilities.
- **Enhance the school district and bus operator customer experience** when deploying electric buses and installing charging infrastructure.
- **Partner with the Department on their electric school bus deployment program**[97] to help support the deployment of electric buses throughout Minnesota.

2. *Operations and Customer Experience*

Below are the key components to the operations and customer experience of our Electric School Bus demonstration project.

a. Participant Selection – School Districts and School Bus Operators.

The Company will work with interested school districts and school bus operators who are also participating in the Department's program to complete a demonstration application. The Company will leverage its proposed Application Review and Scoring

[96] See Docket Nos. E002/M-21-101 and E002/M-17-401. Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action (March 15, 2022) at Order Point 12.
[97] 2023 Minn. Laws, Ch. 60, Art. 12, §35 (Minn. Stat. § 216C.374) https://www.revisor.mn.gov/laws/2023/0/Session+Law/Chapter/60/

Process, as part of its Fleet EV Service and Public Charging Pilot bridge concept[98], to select participants for the additional support discussed herein.

For the Electric School Bus demonstration, the Company will consider the number of buses a school district operates and/or the number of school districts served, and buses operated by the operator, today, under the Project Scope category. Further, we will review anticipated weekly bus utilization to estimate the number of trips, charging events, miles traveled, V2G availability, and overall total potential impact.

To identify the program participants the Company will consider the number of sites used as depots for bus parking, their readiness for bi-directional charging infrastructure installation, their ability to contract, install and launch within the TEP's timeframe, and if they have selected an electric bus capable of use for V2G. The number and types of electric buses also supported through the Department's deployment program and/or the EPA's Clean School Bus Program will also be a factor that will increase a project's score in this area. Any external funding applied to the Company's costs of the charging infrastructure will help increase scores in this category as it will aid overall demonstration cost-effectiveness.

For the Equity and Accessibility category, the Company will utilize tools and resources, like the Minnesota Pollution Control Agency's (MPCA) Environmental Justice Screening Tool[99], to determine whether the applicant's project achieves the Company's objective to focus on disadvantaged communities, such as low-income, BIPOC, and/or rural community students who are disproportionately impacted by diesel emissions and air pollution. We will also review the proportion of students within a school district or school receiving free or reduced lunch plans.[100]

The Company is currently unable to estimate the percent of investments or enrolled participants that will be located in EJ areas.[101] However, the Company is committed to prioritizing such projects and reporting on progress in this area, as described in our proposed reporting requirements.

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[98] See Section III.D.2 for more information about the proposed Application Review and Scoring Process.
[99] MPCA, *Environmental Justice Screening Tool*, Understanding environmental justice in Minnesota (arcgis.com) (last accessed Oct. 4, 2023). The tool highlights areas of concern for Environmental Justice as defined in Minn. Stat. 216B.1691, Subd. (1) (Minn. Session Laws – 2023, Chapter 7, HF7, Sec. 3).
[100] U.S. Environmental Protection Agency, 2022 Clean School Bus (CSB) Rebates Program Guide.
[101] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5H.

b. Installation of EV Charging Infrastructure.

The Company will work with participants to site, design, and install the EV charging infrastructure as it has under the Fleet EV Service Pilot, including any needed distribution upgrades. As part of this coordination, the Company will review and confirm with the participant, whether the electric school buses and EVSE they prefer are V2G-capable. The Company will also complete an interconnection study for the project. The school districts and/or school bus operators will purchase and procure the buses and chargers from the manufacturers or other appropriate sources and coordinate a timeline and plan for delivery to coincide with the Company's installation of the charging infrastructure. The Company will provide a rebate for the participants' eligible V2G charger.

c. Coordination on Charging, V2G Demonstrations, and other Terms.

The Company will require that each participant sign the Company's existing Fleet EV Service Pilot CSA including a V2G Addendum. With the V2G addendum, the CSA includes additional terms to ensure adequate communication and coordination of V2G demonstrations.

Additional parameters include:

- Communication: School districts and school bus operators will agree to contact and communication from the Company (including any of its contractors). The operator must help facilitate coordination and communication between the school district and the Company, to help administer V2G events and collect information and feedback for the purposes of the demonstration.
- Use Restrictions: Restrictions such as availability and event coordination, where the participant must allow the Company to use the buses for V2G demonstrations and permit the Company control of the buses during summer months and any other periods of time agreed upon by the Company.
- Charging: The school district or bus operator must commit to charge the school bus more than 50 percent of the time at the designated charging locations that are V2G capable.
- Data Collection: The school district or bus operator must commit to helping the Company collect information needed to fulfill demonstration objectives and learning goals. Such commitments involve supporting collection and submission of any required data, when and where required by the Company.

- Utility Costs: School bus operators must pass through their fuel and operations and maintenance costs savings and charging expenses to the school districts in accordance with their existing arrangements with school districts.

d. Coordination with the Department's Electric School Bus Deployment Program

Initiatives in the 2023 Minnesota Legislative Session within the new state energy bill included an Electric School Bus Deployment Program to be administered by the Department.[102] The approximately $13 million authorized for the program is intended to provide grants to accelerate the deployment of electric school buses by school districts and to encourage schools to use vehicle electrification as a teaching tool that can be integrated into the school's curriculum. Eligible grant expenditures include payments to school districts or transportation service providers that covers up to 75 percent of the purchase one or more electric school buses and installation of charging infrastructure on their real property.[103]

With this funding appropriation, the Company estimates the Department can facilitate the deployment of about 40 electric school buses, if all grants are directed toward offsetting the upfront cost to purchase electric buses.[104] The Company has begun discussions with the Department and indicated we would like to coordinate as they develop their program so that we can propose a complementary program. Until that time, the Company proposes to support two electric bus projects in the Department's program to facilitate their participation in the Company's V2G demonstration.

The Company is interested in considering additional support for school bus electrification beyond this demonstration, including by providing EVSI to support additional school bus electrification projects in coordination with the Department's new program. The Company looks forward to the further development of the Department's program and plans to provide updates for the Commission about additional opportunities to partner with the Department to support electric school bus deployment in the Company's service territory as those opportunities become clearer. In the meantime, we seek approval for the Demonstration proposed here.

[102] 2023 Minn. Laws, Ch. 60, Art. 12, §35 (Minn. Stat. § 216C.374)
[103] For prioritized school districts, up to 95 percent of the costs can be covered in the grant. Charging infrastructure includes but is not limited to battery exchange stations, electric vehicle infrastructure, and electric vehicle charging stations.
[104] Assumes 40 percent of $13 million is allocated to prioritized school districts (90 percent of bus costs covered), and 60 percent allocated to non-prioritized school districts (75 percent of bus costs covered).

3. *Reporting Requirements*[105]

The Company proposes the following reporting requirements for the Electric School Bus Pilot. All reporting requirements will be reported on annually, unless marked with an asterisk.[106]

- Number of participating school districts, bus operators, buses, and locations. *
- Demonstration incurred costs to provide service, broken out by project. *
- Average energy consumption (kWh) resulting from electric bus charging, broken out by project.
- Total energy consumption (kWh) of the demonstration, resulting from electric bus charging, and the percent of charging occurring during off-peak hours.
- Average energy demand (kW) resulting from electric bus charging, broken out by project.
- Number of V2G events conducted each summer and amount of energy benefitting the grid as a result.
- Percent of participants located in an area of concern for Environmental Justice, according to the MPCA's Screening Tool. *
- Overall participant satisfaction with the demonstration.

The Company may work with a third-party evaluator to help gather and track reporting requirements, and to assess the performance of the demonstration. An evaluation will be conducted over a two-year period, when buses have been delivered, deployed, and charging infrastructure is in-serviced with buses in operation. The exact timing of this evaluation period is dependent upon actual bus delivery and infrastructure and charging installation, and these times may vary due to industry supply chain dependencies outside of the Company's control.

4. *Participation, Costs, and Accounting Treatment*

Table 10, below, summarizes the Electric School Bus demonstration's forecasted budget to support the targeted participation of two electric school buses through the planned scope.[107] The proposed budget does not presume the demonstration's costs will receive support from any external funding sources such as federal or state grants;

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[105] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5F.
[106] An asterisk (*) denotes a reporting requirement that will be reported on both quarterly and annually.
[107] The Company assumes that each electric school bus will be supported by a single V2G EVSE at a 1:1 ratio.

however, it is possible that receipts of such funding could be used to reduce the Company's overall financial contribution to the demonstration. It should be noted that external funding sources are often structured as reimbursements, meaning that even if external funding is received for certain costs, those costs may still be incurred and then later reimbursed.

Table 10
Electric School Bus Demonstration Participation and Budget
($ in Millions)[108]

	2024	2025	2026	2027	Total
Participation					
Electric Buses Supported	0	0	1	1	**2**
V2G EVSE	0	0	1	1	**2**
O&M Costs					
Education & Awareness	$0.0	$0.1	$0.1	$0.2	$0.3
Infrastructure Maintenance	$0.0	$0.0	$0.0	$0.1	$0.1
Program Administration	$0.0	$0.2	$0.2	$0.2	$0.5
Total Annual O&M	**$0.0**	**$0.2**	**$0.2**	**$0.4**	**$0.8**
Capital Costs					
Distribution	$0.0	$0.0	$0.0	$0.0	$0.0
EVSI	$0.0	$0.0	$0.0	$0.0	$0.1
V2G EVSE Rebates	$0.0	$0.0	$0.2	$0.2	$0.3
Information Technology	$0.0	$0.0	$0.0	$0.0	$0.0
Total Annual Capital	**$0.0**	**$0.0**	**$0.2**	**$0.2**	**$0.5**

The O&M expenses associated with the Electric School Bus include:

- **Education and Awareness:** The Company recognizes that education and awareness concerning the Company's demonstration is important. This ensures that stakeholders are actively engaged in learning about, receiving updates on, and participating in the outcomes of the demonstration. Costs for the demonstration may include brochures, informational sheets, white papers, technical papers, direct mail, communications, marketing and advertising campaigns, costs to produce informational videos, in person and digital events, web content, and other mediums that help to best share the information about the demonstration to school districts and bus operators, and the status and outcome of the demonstration to interested stakeholders. We have also included the cross-functional labor needed to support these efforts.

[108] Table may not sum to totals due to rounding.

- **Infrastructure Maintenance:** For the demonstration, the Company will own and operate all distribution and EVSI equipment, which will be maintained by third-party contractors in the same manner as the EVSI is maintained under the Fleet EV Service Pilot.
- **Program Administration:** The Company will support the demonstration project using a combination of full-time employees, contractors, and consultants. Program administration costs will support the development, execution, and evaluation of the demonstration.

The Capital expenditures for the Electric School Bus Demonstration include:

- **Service Connection and EVSI:** The Company will install and own all EVSI infrastructure, including new panels, conduit, wiring, and associated equipment up to the charger, as well as any necessary civil construction work in compliance with state and local codes. This work will be completed by third-party contractors and accounted for in the same manner that similar infrastructure is installed and recorded under the Fleet EV Service Pilot. The Company will also install and own all equipment on the utility's traditional side of the point of service connection. This work will be done by the Company.
- **V2G EVSE:** The Company proposes to rebate two bi-directional, V2G chargers and associated equipment to test vehicle to grid capabilities. As discussed in greater detail in Section IV.B, the Company proposes to place the V2G EVSE rebates in a regulatory asset on which the Company would earn its WACC.

D. Bridge Funding for Fleets and Public Charging

The Company closed its Fleet EV Service and Public Charging Pilots for new enrollment in the spring of 2023 due to their approved budgets being fully allocated to both completed projects and those that are in the design and construction phase.[109]Between these two Pilots, the Company has received expressions of interest from approximately 91 additional potential projects for which the Company has paused efforts and further scoping conversations. Details of these 91 potential projects are included in Appendix H10.

[109] *In the Matter of the Petition of Northern States Power Company's Annual Reporting on Electric Vehicle (EV) Charging Tariffs, Programs, and Pilots.* DOCKET NOS. E002/M-15-111, E002/M-17-817, E002/M-18-643, E002/M-19-186, E002/M-19-559, E002/M-20-711, E002/M-20-745, E002/M-21-101 (June. 6, 2023)

This pipeline of additional fleet and public charging projects includes unique transportation electrification efforts with cities as well as transit and fueling providers.

As shown in Appendix H10, of the 91 projects noted above, the Company has initial project-by-project scopes and cost estimates for certain projects that could move forward under the bridge, including 14 ready-to-execute projects and 32 projects that are likely to move forward, amounting to roughly $8.7 million in capital expenditures[110]. Based on our analysis of the remaining pipeline of 45 potential projects, there is significant interest in commercial transportation electrification among the Company's customers and communities, summing to an estimated $8.7 million in additional fleet and public charging project capital expenditures. Altogether, the Company estimates that the overall pipeline of 91 projects represents approximately $17.3 million in capital expenditures. In alignment with the value of the pipeline, the Company proposes a total pilot bridge budget of $22.3 million, including $17.3 million in capital expenditures and $5 million in O&M.

Both the Fleet EV Service and Public Charging Pilots' services are an important factor in customer transportation electrification plans coming to fruition, by helping advance projects that may stall or be materially reduced without support from the Company. Many of these interested customers have indicated to the Company that without the Pilot's support they may either put their projects on hold or pursue smaller-scale deployments.

To be able to serve this demand within the pipeline and maintain market momentum, the Company is requesting the Commission extend the enrollment period through the end of 2025 for both the Fleet EV Service and Public Charging Pilots and approve additional budget with flexibility, so that the budget can be used between both Pilots as needed to meet customer demand. The Commission previously approved an extension of both pilots, along with the ability to reallocate budget between the two pilots, in 2022.[111]

The Company is currently collecting data and learnings from completed projects to inform a potential future proposal for a permanent program anticipated in 2024. As mentioned, this future proposal for a permanent program is dependent upon the

[110] The Company has designated a project as "ready-to-execute" if the customer was ready to sign an agreement or signed an agreement that the Company was unable to countersign at the point the budget was exhausted. The Company has designated a project as "likely" if its advisory team was actively working with the customer, either in the form of initial meetings and/or site visits or preliminary design.
[111] See the Commission's December 5, 2022 ORDER in Docket No. E002/M-18-643.

learnings and evaluation of these Pilots and relates to the overview of ways we can support the charging market, and work to streamline the Company's internal processes described in Section II.G, above. While this future planning is underway, it remains clear that there are important fleet and public charging projects to be pursued that still need Pilot support, and the absence of any support from the Company during this period makes it difficult for customers to plan for the future. The Company wishes to help its customers and communities achieve their transportation electrification goals while we assess how we can best support commercial charging projects on a post-Pilot basis.

1. *Operations and Customer Experience*

To ensure that the incremental funding is used to support both charging use cases (fleet and public charging), the Company is proposing to reserve a minimum of 15 percent of the budget for each use case. As such, the Company commits that approximately $3.3 million of the total budget will be initially allocated for fleets and approximately $3.3 million will be initially allocated for public charging. The remaining budget of approximately $15.7 million can be used for either fleet or public charging, depending on customer demand and outcomes of application review and scoring, as discussed in more detail below.

It is critical to understand that the Company's discussion of the potential for supporting more than 91 total projects with $22.3 million is a high-level, preliminary estimate at this time representing a top end of support the Company could bring to bear if all currently identified projects decide to move forward, and costs incurred are consistent with preliminary forecasts.

As discussed in the Company's 2023 Annual EV Reporting, forecasting the number and scope of commercial EV projects and respective budgets is challenging due to the considerations that are known at the outset of project planning, and those that may be later uncovered as projects move through design and construction.[112] With this $22.3 million bridge proposal, the Company has built in contingency for all 91 projects, but acknowledges that not all 46 well-scoped projects nor the remaining 45 potential projects may move forward, and a project may not move forward at the currently

[112] As discussed in the MDU Budget Expansion Request, Docket No. E002/M-20-711 potential project considerations include; time needed to order and place new transformers, the requirement that all meters must be accessible to the Company 24 hours and seven days per week, nuances due to overall building and parking structure, subsurface condition complexities that are unknown until construction commences, ancillary construction costs like traffic control and restoration, and adjustments to the number of chargers to be deployed made by applicants during the design phase.

forecasted costs due to evolving customer preferences, decisions, timing, and unforeseen design and construction considerations that are largely outside of the Company's current knowledge and control. To be clear, the Company anticipates that some currently identified projects may not proceed at all, however, other projects are likely to materialize that would take their place through the pendency of this bridge proposal. The main purpose of this bridge proposal is to maintain a consistent option for support from the Company for fleet and public charging projects until a long-term approach is identified.

We work to coordinate closely throughout a project's lifecycle to mitigate risks. However, compared to traditional power generation, transmission, and distribution work, the Company does not yet have extensive experience in this area, and is learning from executing many different types of commercial EV charging EVSI projects. The Company expects to continue gathering key learnings delivered from this bridge proposal on what it takes to advance fleet and public charging projects and inform best-in-class future program proposals.

2. Customer Selection Process

The Company brings forward a proposed Commercial EV Pilot Application Review and Scoring framework[113] to be implemented for this bridge proposal. Upon receipt of project applications, the Company will review and score them on a rolling basis across three scoring categories: Project Scope, Customer and Project Readiness, and Equity and Accessibility.

Every project application will be evaluated on a satisfactory scale of zero to three for each scoring category and underlying criteria. As shown in our Application Review and Scoring Worksheet, provided as Appendix H11, there are 300 total points available for each project to earn during the scoring review, with 45 percent of the points allotted to the Project Scope category, 20 percent to Customer and Project Readiness, and 35 percent to Equity and Accessibility. Applications that score 66 percent of the points or higher will qualify to participate and move on to the design and construction phase of the Pilot participation.

3. Reporting Requirements[114]

[113] The Company previously proposed this framework in Docket No. E002/M-22-432. Callinan Direct and Schedule 2 (Exhibit 101 NAC-1, Schedule 2).
[114] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5F.

The Company plans to continue to report on the Fleet and Public Charging Pilots consistent with the annual and quarterly reporting requirements already established by the Commission for these pilots.

4. *Participation, Costs, and Accounting Treatment*

Table 11 provides a detailed overview of the Company's forecasted participation and budget for this bridge proposal. The Company estimates that approximately 59 percent of participation will be in EJ areas, based on the proportion of the 46 projects that are already well-identified.[115]

Table 11
Estimated Pilot Bridge Participation and Budget
($ in Millions)[116]

	2024	2025	2026	2027	Total
Participation					
Fleet Ports	27	40	0	0	**67**
Public Charging Ports	304	375	0	0	**678**
O&M Costs					
Education & Awareness	$0.3	$0.3	$0.0	$0.0	**$0.5**
Infrastructure Maintenance	$1.1	$1.6	$0.0	$0.0	**$2.7**
Program Administration	$0.6	$0.7	$0.0	$0.0	**$1.3**
Information Technology	$0.2	$0.2	$0.0	$0.0	**$0.4**
Total Annual O&M	**$2.1**	**$2.9**	**$0.0**	**$0.0**	**$5.0**
Capital Costs					
Distribution	$0.0	$0.0	$0.0	$0.0	**$0.0**
EVSI	$6.0	$9.8	$0.0	$0.0	**$15.7**
EVSE	$0.0	$0.0	$0.0	$0.0	**$0.0**
Information Technology	$0.6	$1.0	$0.0	$0.0	**$1.5**
Total Annual Capital	**$6.6**	**$10.7**	**$0.0**	**$0.0**	**$17.3**

[115] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 5H.
[116] Table may not sum to totals due to rounding.

E. Expanded Residential Advisory Services

To support growing customer interest in EVs and participation in managed charging and the introduction of two new managed charging programs (EVAAH – Subscription and Home Wiring Rebate Program), we plan to expand and improve our Residential Advisory Services to enhance the customer experience and foster greater awareness about EVs. Our advisory services aim to create an easy customer experience and deliver the upfront education and awareness, and consultation via tailored, real-time support and tools that customers need to identify transportation electrification opportunities and to make informed decisions about their plans as they consider installing EV charging infrastructure.

Our Residential Advisory Services today span three main areas—Education and Awareness, EV Advisor Online Tool, and Trade Ally Engagement. Based on what we know to be effective efforts, and in response to the Commission's recent Order requesting the Company to focus on "other non-infrastructure related pilots or programs that increase EV deployment, especially in disadvantaged communities,"[117] we propose to expand our Residential Advisory Services considering opportunities for additional engagement. For 2024, the Company has identified opportunities to support increased education and outreach efforts while staying within the scope of the total EV program O&M budgets already included in rates for 2024 under the Company's multi-year rate plan (MYRP). Table 12 below shows the planned annual budget for Residential Advisory Services.

Table 12
Residential Advisory Services Budget
($ in Millions)[118]

	2024	2025	2026	2027	Total
O&M Costs					
Education and Awareness	$0.7	$0.9	$1.1	$1.1	**$3.8**
EV Advisor Online Tool	$0.1	$0.1	$0.1	$0.1	**$0.4**
Trade Allies	$0.4	$0.7	$0.7	$0.8	**$2.6**
Total Annual O&M	**$1.2**	**$1.7**	**$1.9**	**$2.0**	**$6.8**

Of specific note, with additional funding for Education and Awareness activities, the Company can build upon successful sponsorship and event campaigns with HOURCAR to promote the Evie Carshare service. The Company's sponsorship and

[117] *See* ORDER ACCEPTING WITHDRAWAL OF CLEAN TRANSPORTATION PORTFOLIO SUBJECT TO CONDITIONS (August 23, 2023), Docket No. E002/M-22-432, Order Point 4C
[118] Table may not sum to totals due to rounding.

event contributions help lower HOURCAR's costs, and thus, Evie Carshare pricing for low-income customers, generating greater awareness and access to electric transportation for disadvantaged communities. As noted in HOURCAR's recent report, 38 percent of utilization in Evie Carshare service was derived from BIPOC[119]/non-white users, as well as 36 percent from very low-income users and 11 percent from BIPOC/non-white users who are also very low income.[120] There is great opportunity to work with HOURCAR to increase those utilization rates.

Regarding the EV Advisor Online Tool, the Company has plans to expand the available language translations of this key educational platform. The Company previously made a Spanish version available and with this increased budget will plan to support the top three non-English speaking languages in our Minnesota service territory, by adding Hmong and Somali.

As for Trade Ally engagement, expanding our successful efforts in this area will be key to ensure trade allies, like auto dealers and local electricians (and as a result, our mutual customers), are aware of our managed charging programs and incentives. We have so far seen an uptick in enrollment in managed charging programs originating from the auto dealership program, and we will continue to focus on and enhance that conversion rate with more funding. With the introduction of the Home Wiring Rebate Program which requires managed charging participation, it will be critical to create additional resources and tools for local electricians to utilize when installing residential EV charging infrastructure so they can support increased program enrollments.

F. Information Technology

To support the programs included in this TEP, it is necessary to expend costs for IT development and maintenance. Costs for IT include both capital and O&M expenditures. This spending contributes to customer enrollment journeys, charger and charging management solutions such as V2G, customer facing tools, integrations with existing systems, and solutions supporting data insights and reporting capabilities among other efforts.

- **Customer Enrollment Journeys:** IT support for customer enrollment journeys includes efforts to make the Company's offerings more easily navigable and attractive to potential participants. Examples of such efforts

[119] BIPOC stands for Black, Indigenous, and people of color.
[120] HOURCAR. *2022 Impact Report*, 2022-HOURCAR-Evie-Impact-Report-Online-FINAL.pdf (last accessed May 25, 2023).

include technology for residential and commercial program enrollment, customer communication, intake, and identification of needs for advisory services. Enrollment journeys also provide customers with information about aspects of EV adoption, such as rate selection and available incentives. These efforts support all programs described in the TEP.

- **Charger and Charging Management Solutions:** Charger and charging management solutions are efforts to provide customers options for charging optimization and to help provide transparency into charging behavior and clean transportation adoption. Further, the Company expects to incur some costs to facilitate its V2G demonstrations.
- **System Integrations:** Integrations with existing systems are critical in creating a seamless customer experience. Billing system integrations support new and updated program options for various customer segments. Integrations also support internal processes that allow for more flexible offerings that help participants overcome difficult adoption barriers.
- **Data Insights and Reporting:** The Company plans to gain as much insight as possible into the pipeline of potential participants, current participants, and past participants in programs. Costs for IT needed for these efforts will support effective use of data, increased capabilities to report internally and externally and support grid reliability.

As shown in Table 13, the Company has forecasted more IT spend in 2025 than 2024 or 2026. However, the actual timing of IT-related spending will depend on program implementation. Table 13 below summarizes the planned budget for IT.

Table 13
Budget for Information Technology
($ in Millions)[121]

	2024	2025	2026	2027	Total
O&M Costs					
Total Annual O&M	$0.2	$0.3	$0.1	$0.2	**$0.9**
Capital Costs					
Total Annual Capital	$0.7	$1.2	$0.2	$0.3	**$2.4**

[121] Table may not sum to totals due to rounding.

G. Cost-Benefit Analysis of New Proposals

The Company has completed a CBA assessing the programs, pilots, and demonstrations proposed in this TEP. In our CBA analysis the Company compared all costs associated with proposals in its TEP filing plus the cost to serve EVs adopted within its service territory to the benefits derived from said EVs. Costs are comprised of the net present value of the revenue requirements associated with TEP capital expenditures (capex), TEP O&M costs, and the electrical system costs to serve EVs adopted within the service territory. Benefits from EV adoption includes downward rate pressure realized from incremental energy sales, maintenance and fuel cost savings experienced by EV drivers, and environmental benefits associated with reduced emissions. This type of CBA has been part of the Company's Conservation Incentive Program (CIP). This same methodology was used for the CBA provided with this TEP to limit the number of new assumptions being adopted in the analysis.

The CBA analysis presents results from several test perspectives; the Participant Test, Utility Test, Rate Impact Test, Societal Test, and Minnesota Test (revised Societal Test). Each test is based on comparing the ratio of the net present value of program benefits to the net present value of program costs. The values associated with system and environments benefits/costs are those provided by the CIP and approved by the Department for years 2024-2026. Since CIP has not approved values beyond this time the 2026 values were carried forward to cover year 2027 of the TEP. The CBA analysis is provided as Appendix H12. Table 14 below provides the annual benefit/cost ratio for the participant, rate impact, and societal tests. Please note that a value greater than one means that the benefits under that test outweigh the costs.

Table 14
Cost-Benefit Analysis Summary

Year	Participant Test	Rate Impact Test	Societal Test
2024	1.05	2.59	1.33
2025	1.05	2.51	1.34
2026	1.07	2.44	1.36
2027	1.07	2.41	1.36

H. Budgets and Cost Recovery

In this section, we provide both five-year and ten-year budgets for our Transportation Electrification pilots, programs, and demonstrations. We also provide a discussion of how costs are allocated between Xcel Energy's different jurisdictions and the status of cost recovery in those other jurisdictions.

1. *Five-year Budgets for Transportation Electrification*

Table 15 summarizes the Company's expected future expenditures for its current and proposed transportation electrification pilots and programs for the next 5 years.

Table 15[122]
Transportation Electrification Spending: 2024 – 2028
($ in Millions)

Budget Category	Capital	O&M	Marketing and Comms.	Other	Total
EVSI[123]	$23.2	$4.1	$0.0	$0.0	**$27.3**
EVSE[124]	$7.5	$4.2	$0.0	$0.0	**$11.7**
O&M & Mrktg. Comm.	$0.0	$4.1	$9.4	$0.0	**$13.5**
IT	$3.1	$1.3	$0.0	$0.0	**$4.4**
School Bus Demo	$0.5	$0.8	$0.0	$0.0	**$1.3**
Total	**$34.3**	**$14.5**	**$9.4**	**$0.0**	**$58.2**

2. *Ten-year Budgets for Transportation Electrification[125]*

As an enterprise, the Company does not budget on a ten-year horizon. Rather, the Company budgets on a five-year basis. While this is not our typical practice, we provide estimated forecasted budgets for our transportation electrification pilots and programs over the next ten years in Table 16 below. The forecast assumes approval of the proposals in this TEP and that spending will continue for all EV programs. The forecast assumes approval of the bridge proposal in this TEP for the fleet and public charging pilots, as well as the school bus demonstration, but does not assume additional capital costs for commercial EV pilots or demonstrations beyond what is proposed in this TEP, though ongoing O&M costs are included for all pilots.

[122] Provided in Compliance with Order Points A.29.i and F.11 of the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879.
[123] Includes both EVSI and distribution upgrade costs.
[124] Forecast includes residential EVSE only, though some EVSE may also be supported through commercial pilots.
[125] Provided in compliance of Order Point 5.E of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.

Table 16
Transportation Electrification Spending: 2024 – 2033
($ in Millions)

Budget Category	Capital	O&M	Marketing and Comms.	Other	Total
EVSI[126]	$58.5	$27.2	$0.0	$0.0	**$85.6**
EVSE[127]	$42.6	$28.1	$0.0	$0.0	**$70.7**
O&M & Mrktg. Comm.	$0.0	$4.1	$20.5	$0.0	**$24.6**
IT	$10.1	$6.0	$0.0	$0.0	**$16.1**
School Bus Demo	$0.5	$0.9	$0.0	$0.0	**$1.4**
Total	**$111.6**	**$66.3**	**$20.5**	**$0.0**	**$198.4**

3. *Allocation and Cost Recovery of Costs Shared with Other Jurisdictions*[128]

Most costs incurred by the Company for EV-related projects are assigned directly to the jurisdiction where the costs are incurred, including costs related to distribution system work, EVSI, EVSE, and other costs related to specific EV projects. In our TEP portfolio budget shown in Table 8 above, the costs shown for each of the individual programs (EVAAH – Subscription, EV Home Wiring Program, Electric School Bus Demonstration, and Commercial EV Pilot Bridget) will all be assigned directly to Minnesota.

The cost of IT work related to our advisory services and the labor related to program administration are shared between jurisdictions as that work can apply to all our jurisdictions with transportation electrification efforts. In Table 8 above, those costs would be shown under residential advisory services and IT. To record costs in a consistent and equitable manner, costs are direct assigned when attributable to a specific jurisdiction, and when costs cannot be directly assigned, they are considered common costs which are then assigned to homogenous cost categories. Costs in these groupings are allocated to the jurisdictions using cost causation analysis whenever possible. The Company's Cost Allocation and Assignment Manual provides the details of our cost allocation principles.

[126] Includes EVSI and distribution upgrade costs.
[127] Forecast includes residential EVSE only, though some EVSE may also be supported through commercial pilots.
[128] Provided in compliance with Order Point 5.A of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.

For the costs allocated to Minnesota, we intend to recover these costs as a part of our currently established base rates. Our cost recovery proposal for new proposals in this TEP is discussed in greater detail below. For costs allocated to Public Service Company of Colorado (PSCo), the costs will be recovered through an established Transportation Electrification Programs Adjustment Rider. For costs allocated to Southwestern Public Service Company, costs will be recovered through an EV Rider in New Mexico. For costs allocated to Northern States Power Company-Wisconsin, costs will be recovered through base rates.

IV. COST RECOVERY, ACCOUNTING TREATMENT, AND BILL IMPACTS

A. Cost Recovery Methods[129]

The Company is not proposing a specific cost recovery method for the costs proposed in this TEP filing. Rather, we are simply requesting approval of additional budgets to complete the work as needed. The Company will seek to recover the projects with the acknowledgement that the Company will bear the burden of proving the prudence of costs related at that time.

The recently approved rate case was a multi-year rate plan extending through 2024. While there are no definitive plans to file a rate case, it is possible that the Company will file a rate case in 2024 or after to establish new base rates after the multi-year rate plan is complete. If we do file a new rate case in 2024, we would likely include the capital and O&M costs of expected transportation electrification projects within our base rate request. If a future rate case is not filed and future costs exceed those set in our current base rates, the Company will propose a recovery mechanism for the incremental costs in an appropriate regulatory docket.

Revenues generated from TEP programs will be treated like revenues from many of the other utility services the Company provides. When received, revenues will be tracked by customer type and will be recorded in their respective rate classes under which they take service. These revenues will help fulfill the Company's overall revenue requirement. Revenues will not directly offset program costs and capital costs will remain at full value to be eventually offset via depreciation expense.

[129] Provided in compliance of Order Points 5.B and 5.D of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.

The Company has included a proposal to offer home wiring rebates and rebates for V2G chargers for the school bus demonstration as a part of our transportation electrification portfolio in this TEP. As a part of this, we are requesting the ability to place the cost of these rebates in a regulatory asset, which will allow us to recover the cost of the rebates and earn a return on their value. While we have not received approval for this type of recovery in the past, we believe the new Minnesota Energy Bill grants the Commission authority to approve a rate of return on rebate expenditures. Specifically, the new bill states:

> *Notwithstanding any other provision of this chapter, the commission may approve cost recovery under section 216B.16, including an appropriate rate of return, of any prudent and reasonable investments made or expenses incurred by a public utility, including rebates for the installation of electric vehicle infrastructure, to administer and implement an approved transportation electrification plan.*[130]

We respectfully ask that the Commission consider our request to capitalize rebates as a regulatory asset under the guidance of the new Minnesota Energy Bill.

B. Accounting Treatment for Rebates

The Company is requesting that the Commission grant approval to establish a regulatory asset for the cost of the home wiring rebates as well as rebates for the cost of V2G EVSE. Under this proposal, when the Company pays a rebate, it would be recorded as a regulatory asset. We would carry the regulatory asset as a capital asset and include a request to amortize and recover the cost of the rebates in a future rate case. By including the regulatory asset in rate base in a future rate case request, the Company will be able to earn a return on the capitalized balance. The balance of the regulatory asset would build over time as more rebates are paid. These costs would be recorded in FERC Account 182.3, Other Regulatory Assets. To recover the balance of the regulatory asset, the amount would be amortized over a prescribed period as determined in the future rate case. At this time, we would anticipate an amortization period of ten years.

Using a regulatory asset will allow us to offer a larger program benefit immediately, as we amortize the costs over ten years and avoid the pass-through cost impact that would occur were the rebates treated as an O&M expense and expensed in the year they are paid. This treatment allows us to make investments now to support our

[130] 2023 Minn. Laws, Ch. 60, Art. 12, §12, Subd. 4

customers and the State's EV goals, while spreading the costs out over a longer period to lessen the impact.

The Company recognizes that the rebates it proposes here are not the first time the Company has proposed rebates as part of a customer program, and notably, rebates are commonly used in the Company's demand side management (DSM) portfolio. However, this is the first time the Company is requesting approval of rebate programs relating to EV infrastructure.[131] The Company requests that the Commission find that the appropriate rate of return for EV infrastructure rebates provided by the Company is the Company's weighted average cost of capital (WACC).

The Company's support for EV infrastructure under the TEP presents a unique opportunity to provide rebates to support transportation fueling infrastructure, whether that infrastructure is home wiring or EVSE (chargers) in the home or in a commercial or other public location. While the Company does provide rebates in its DSM portfolio for a variety of equipment, appliances, controls, and other items that perform various functions such as lighting, heating, cooling and insulation, the TEP and EV infrastructure rebates serve a specific purpose related to advancing transportation electrification.

The Company's WACC represents its true financing cost, and it is appropriate to reflect that cost for the Company's infrastructure investments, whether those investments are in the form of utility-owned infrastructure or rebates for infrastructure owned by others. This approach is consistent with commission decisions in other jurisdictions[132] and is comparable to the way the Company makes other investments in the distribution grid.

Minnesota is still in the early days of the shift to transportation electrification. The Company is well positioned to continue its market support, but to provide support in the form of rebates as the Company believes is desired by various stakeholders, the Company requires cost treatment of its rebates on a comparable basis as it makes its other investments. That similarity of cost treatment provides an incentive to the Company to provide rebates where appropriate to meet customer and market needs, allowing it to deploy its capital to support the further growth of transportation electrification and its associated needs.

[131] EV infrastructure is defined in 2023 Minn. Laws Ch. 60, Art. 12, 12, Subd. 1(e).
[132] *See* e.g. Colorado Public Utilities Commission Decision No. C21-0017; New Mexico Public Regulation Commission Final Order in Case No. 20-00150-UT.

C. EV Portfolio Bill Impacts[133]

To estimate the potential impact to customer bills, the Company has prepared a bill impact analysis. The analysis uses the estimated revenue requirement of the proposals in this TEP and anticipated sales to determine a rate impact for all customers per kWh.

Table 17 below provides the estimated retail rate impact from the transportation electrification portfolio included in this filing. We anticipate that the bill impact for the average residential customer will be about $.05 per billing period in 2024, growing to be about $0.24 in 2027.

Table 17
Estimated Bill Impacts of Transportation Electrification Portfolio

	2024	2025	2026	2027
Residential				
Revenue Requirement	$695,346	$1,545,188	$2,277,399	$3,495,442
Sales (MWh)	8,827,479	8,757,205	8,715,964	8,660,736
Rate Impact (Cents per kWh)	0.00788	0.01764	0.02613	0.04036
Bill Impact	**$0.05**	**$0.11**	**$0.16**	**$0.24**
Demand Billed				
Revenue Requirement	$3,894,604	$6,994,480	$5,566,443	$5,655,862
Sales (MWh)	18,385,204	18,324,366	18,275,261	18,220,536
Rate Impact (Cents per kWh)	0.02117	0.03817	0.03046	0.03104

V. PROPOSED TARIFF CHANGES

In the Company's most recent rate case, the Commission ordered the Company to include a proposal to waive cost sharing requirements for EV-rate customers within this TEP.[134] The Company's internal policy is to waive customer contributions in aid of construction (CIAC) for line extensions, transformer upgrades, and other system costs required to facilitate customer participation on our EV tariffs. While exemptions for CIAC requirements are specifically called out within the tariffs for our commercial EV pilots, our residential programs and pilot tariffs and CIAC rules did not include any reference to this practice. To ensure that this methodology is clear within our

[133] Provided in compliance of Order Points 5.B and 5.D of the Commission's August 23, 2023 Order in Docket No. E002/M-22-432.
[134] *See* FINDINGS OF FACT, CONCLUSIONS, AND ORDER (July 17, 2023), Docket No. E002/GR-21-630, Order Point 66.

tariffs, the Company is proposing several changes to our Minnesota Electric Rate Book.

To mirror the language already included in our commercial EV pilot tariffs, we are recommending adding the following language to Section No. 5, Page Nos. 6, 7, 8, and 8.3:

> *Company waives CIAC requirements for residential customers under the Standard Installation and Extension Rules under Section 5.1 (A)(1)(a), Section 5.1(A)(2) and (3), and Section 5.2 of the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27.*

With this change all our residential and commercial EV program tariffs will explicitly waive the CIAC requirements. In addition to these changes, we also propose adding language within our General Rules and Regulations within our Minnesota Electric Rate Book dedicated to installation costs. Specially, we are recommending adding language like that noted above to Section No. 6, Page Nos. 23, 24, and 27. The Company's proposed tariff changes related to sharing of system upgrade costs are shown in Appendix H13.

In addition, as discussed earlier the Company is also proposing changes to EV Accelerate At Home tariffs, specifically to support introducing the Subscription and BYOC Subscription tariff as well as clarify within the CSA certain program and eligibility requirements. This includes clarification around the required initial electrician visit for BYOC participants and liability of damage from fire, flood, or other disasters. The CSA for the subscription service has been tariffed in Section No. 7 of our Minnesota Electric Rate Book. The changes to the program tariff are to Section No. 5, Page Nos. 8.1, 8.2, and 8.3. The CSA changes are to Section No. 7, Page Nos. 113.1, 114, 115, 115.1, 117, 117.1, 120, and 121. The changes to the subscription service tariffs and CSA are shown in Appendix H6.

CONCLUSION

The Company is pleased to submit this TEP for the Commission's consideration. We believe that the TEP lays out our vision for the future of transportation electrification in our service territory. We respectfully request that the Commission accept this TEP in Compliance with their established reporting requirements as well as approve the following proposals:

- An expansion plan for the current EV Subscription Service Pilot,

- A Home Wiring Rebate program to help reduce upfront charging infrastructure costs and encourage managed charging,
- Expanded Residential Advisory Services,
- Support for Electric School Bus projects to support Vehicle-to-Grid (V2G) demonstrations, and
- Bridge funding for both the Fleet EV Service and Public Charging Pilots to continue supporting important commercial electrification projects.

Finally, we ask that the Commission approve our proposed tariff changes and our request to capitalize rebates for home wiring and for school bus charging equipment.

Source (Docket Nos. or Minn. Law.)	Order Date	Reporting Requirement	Reference
19-186	7-Oct-19	8. In propsing any permanent electric vehicle subscription service, Xcel shall do the following:	
		A. Use a rate design that is more refletive of hourly systems costs with a price signal designed to reduce peak demand.	Appendix H, Section III.A.1 Appendix H5
		B. Examine an option of charging a monthly fee that would not reflect the cost of installing or maintaining a charger, for customers who buy, install, and maintain their own chargers**—or explain why it is not feasible or prudent to do so, and provide cost infromation to support this position**	Appendix H, Section III.A.1
21-694 17-879	8-Dec-22	**A. Baseline Distribution System and Financial Data**	
		21. Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty)	Appendix E, Table E-4
		22. Total number and capacity of public access electric vehicle charging stations, broken out by:	
		a. Number and capacity of known public acesss Level 2 Charging Stations	Appendix E, Table E-5
		b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program	
		c. Number and capacity of known public access direct current fast charging (DCFC) stations	
		d. Number and capacity of DCFC installed through a utility EV program, broken out by program	
		e. All other known EV charging stations (by type, ex DCFC, Level 2)	
		Financial Data	
		26. Historical distribution system spending for the past 5-years, in each category:	
		i. Electric Vehicle Programs	
		1) Capital Costs	Appendix H, Section I.B.1, Table 3
		2) O&M Costs	
		3) Marketing and Communications	
		4) Other (provide explanation of what is in "other")	
		29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:	
		i. Electric Vehicle Programs	
		1) Capital Costs	Appendix H, Section III.H.1, Table 15
		2) O&M Costs	
		3) Marketing and Communications	
		4) Other (provide explanation of what is in "other")	
		Electric Vehicles	
		34. A sumamry table with the following information for each EV rate offering or program during the reporting period:	
		a. Number of customers and/or vehicles enrolled at the end of the reporting period	Appendix H, Section I.B, Table 2
		b. Total energy consumed (MWh) during each EV tariff charging period	
		c. Peak demand (MW) and the date and time at which it occurred.	
		35. Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify).	Appendix H, Section I.B.2
		C. Distributed Energy Resource Scenario Analysis	
		1…For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).	Appendix A1, Section II.B.7, Tables A1-8 and A1-9
		F. Transportation Electrification Plan	
		1. Xcel shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.	Appendix H, Section I.B, Table 1
		2. Xcel shall provide a discussion of how it plans to facilitate:	
		a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory;	Appendix H, Sections I.B.5 and II.C
		b. availability of residential charging options for both single family and multiple unit dwellings;	Appendix H, Section I.B.3

Source (Docket Nos. or Minn. Law.)	Order Date	Reporting Requirement	Reference
		c. programs or tariffs in development to address flexible load or reduce metering and data costs; and	Appendix H, Section II.D
		d. fleet electrification.	Appendix H, Sections I.B.4 and II.B
		3. Xcel shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.	Appendix H, Section I.B.3
		4. Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.	Appendix H, Sections I.B.3
		5. Xcel shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 20-745 at the conclusion of the pilot program.	Appendix H, Section II.C.4
		6. Xcel shall provide evaluations of non-pilot EV programs that examine the cost□effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.	Appendix H. Section II
		7. Xcel shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.	Appendix H, Section I.B.6
		8. Xcel shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).	Appendix H, Section I.C and Appendix H2
		9. Xcel shall provide citations with links to the most recent reports for any ongoing EV pilots or programs.	Appendix H, Section I.B
		10. Xcel shall provide historical spending for the past 5-years on all transportation electrification initiatives, broken down across the sections of its budget.	Appendix H, Section I.B.1, Table 3
		11. Xcel shall provide future spending for the next 5-years on all transportation electrification initiatives, broken down across the sections of its budget.	Appendix H, Section III.H.1, Table 15
21-630	17-Jul-23	66. Xcel must include its proposal to waive cost sharing requirements for EV-rate customers to Xcel's Transportation Electrification Plan.	Appendix H, Section V and Appendix H13
22-432	23-Aug-23	2. Xcel shall file a Transportation Electrification Plan by November 1, 2023, that is consistent with 2023 Minn. Laws. Ch. 60, Art. 12, Sec. 12.	Appendix H
		3. In its November 1, 2023, TEP, Xcel shall include the following components in addition to other proposals that comply with 2023 Minn. Laws. Ch 60, Art. 12, Sec. 12:	
		A. The Electric School Bus Pilot.	Appendix H, Section III.C
		B. An analysis of the gaps in public DCFC EV-charging infrastructure that exist throughout its service territory. In its development of this analysis, Xcel should collaborate with thrid-party charging companies and other stakeholders to incorporate known private sector infrastructure deployement plans for Minnesota. The analysis should:	
		i. Use forecasts for EV adoption consistent with the adoption scenarios Xcel uses in its other planning processes such as integrated distribution planning and resource planning.	Appendix H, Section II.C.7.a
		ii. Identify both general locations and the size of public DCFC infrastructure necessary to supply future EV charging needs.	
		iii. A high-level comparison of the ways Xcel could play a role to support the efficient, cost-effective development of Minnesota's public DCFC charging network and the pros and cons of each option. This should include, but is not limited to, an analysis of make-ready infrastructure programs, rebates for EV supply infrastructure and EV supply equipment, and utility ownership of DCFC.	
		4. In its TEP filed no later than November 1, 2023, Xcel shall focus on at least the following areas of EV program development:	
		A. Managed charging programs, including modifications to existing programs that could increase enrollment.	Appendix H, Section I.B.3
		B. Policy issues related to allocation of distribution-system upgrade cost as referred to the TEPs from the Commission's July 17, 2023 order in Xcel's recently concluded rate case (Docket E-002/GR-21-630).	Appendix H, Section V and Appendix H13
		C. Other non-infrastructure-related pilots or programs that increase EV deployment, including pilots or programs that serve disadvantaged communities.	Appendix H, Section III.E
		D. Vehicle-to-grid pilot projects (which could be the Vehicle-to-Grid School Bus Pilot) that focus on the technical aspects of vehicle-to-grid deployment.	Appendix H, Section III.C
		E. Streamlining and improving Xcel's internal processes related to EV-infrastructure deployment. This should include streamlined approval processes for third parties seeking to install charging infrastructure outside of existing EV Infrastructure Pilot projects, and assistance such as dedicated navigators who can guide companies installing third-party infrastructure through the interconnection process including selecting the appropriate rate structure.	Appendix H, Section II.G
		F. A commitment to work with the Department to ensure electric school bus projects and pilots are consistent with Minn. Stat. § 216C.374.	Appendix H, Section III.C
		5. In its TEP filed no later than November 1, 2023, Xcel shall include the following information:	

Source (Docket Nos. or Minn. Law.)	Order Date	Reporting Requirement	Reference
		A. An indication of where any costs are shared with other operating jurisdictions (for example, the development of EV advisory tools for use across operating companies) and how those costs are allocated and proposed for cost recovery. Xcel shall indicate the status of such cost-recovery requests in other jurisdictions.	Appendix H, Section III.H.3
		B. The potential method of cost recovery, including the allocation of TEP costs and anticipated revenues for each customer class.	Appendix H, Section IV.A
		C. The estimated bill impacts of the TEP, broken down by program proposal, for each customer class.	Appendix H, Section IV.C
		D. What will happen to the revenues generated from TEP programs, including whether the revenues will directly offset program costs.	Appendix H, Section IV.A
		E. For any pilots and programs that are estimated to last beyond the proposed timeframe of the TEP, estimated 10-year capital and operations-and-maintenance budgets.	Appendix H, Section III.H.2
		F. For any proposed pilots, Xcel must propose quantifiable metrics and targets, including accessibility and affordability, that will be reported on a quarterly basis to track pilot progress. Xcel shall also propose annual reporting requirements and a process for pilot evaluation.	Appendix H, Sections III.A.5, III.B.4, III.C.3, III.D.3
		G. For any proposed programs that have been approved in other jurisdictions, Xcell shall include annual reports, evaluation, or other results showing the impacts of the programs including program costs and revenues as links or attachments.	Appendix H2
		H. A breakdown by proposal of what percent of investments or enrolled customers Xcel estimates will be located in environmental-justice areas as defined in Minn. Stat. § 216B.1691, subd. 1(e) (2023 Minn. Laws ch. 7, sec. 3).	Appendix H, Sections III.B.5, III.C.2.a, III.D.4

State	Filing Name	Docket No.	Included Pilots and Programs	Status	Link to Filing
Colorado (PSCo)	TEP 2021-2023	20A-0204E	Home Charging Service	In Market	https://www.xcelenergy.com/company/rates_and_regulations/filings/transportation_electrification_plan
			Standard Home Wiring Rebate		
			Income-qualified rebate		
			Shared Parking – Site Hose Provided Equipment		
			Shared Parking-Full Service		
			Assigned Parking – Full Service		
			New Construction Rebate		
			MFH Income-Qualified Rebate		
			Fleet & Workplace		
			Fleet & Workplace – Optional Charger Service		
			Fleet & Workplace – Income-Qualified		
			Community Charging Hubs		
			Community Charging Hub – Income-Qualified		
			Public DCFC		
			Public Services DCFC		
			Small Commercial Rebate		
			Residential and MDH Advisory Services		
			Fleets Advisory Services		
			Community Advisory Services		
			New EV Rebate (income-qualified customers only)		
			Used EV Rebate (Income-qualified only)		
	S-EV Rate 2	21AL-0409E	Schedule S-EV Rate	In Market	https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search Search "21AL-0409E" under Proceeding Number
			Schedule S-EV-CPP Rate		
			Company Owned DCFC Public Charging Station Rate		
			Performance Incentive Mechanism (PIM) for 2021-2023 TEP		
	TEP 2024-2026	23A-0242E	Residential Advisory Services	Pending	Xcel Energy - Transportation Electrification Plan
			Commercial Advisory Service		
			Community Advisory Services		
			Residential EV Rebate Program		
			TNC and DNC High-Mileage Rebate Program		
			TNC Rental Fleet Rebate Program		
			Governmental EV Rebate Program		
			Public Charging Acceleration Network		
			EV Accelerate at Home (EVAAH)		
			EV Charger and Wiring Rebate		
			Managed Charging Program		
			Commercial EVSI		
			Primary General and Transmission General Wiring Rebate		
			Commercial New Construction Wiring Rebate		
			L2 Charger Service		
			Level 2 ("L2") Charging Rebate		
			Commercial Equity L2 Charger Rebate		
			No Regrets Investments – Distribution Grid Reinforcement		
			Customer-Sited Batteries		
			Special Application Vehicle Electrification ("SAVE")		
			V2X Demonstrations		
			School Bus Electrification		

State	Filing Name	Docket No.	Included Pilots and Programs	Status	Link to Filing
Wisconsin (NSP-W)	EV Service Programs	4220-TE-104	Residential EV Service Programs Tariff	In Market	https://apps.psc.wi.gov/pages/viewdoc.htm?docid=379775
			EVAAH (Standard and Voluntary)		
			Commercial EV Service Program Pilot (Infrastructure and Optional charger services)		
			Commercial EV Service Program Tariff		
	EV Advisory Services	4220-UR-125	Residential Advisory Services	In Market	https://apps.psc.wi.gov/ERF/ERFsearch/content/searchResult.aspx?UTIL=4220&CASE=UR&SEQ=125&START=none&END=none&TYPE=none&SERVICE=none&KEY=none&NON=N
			Commercial Advisory Services		
			Fleet Electrification Advisory Program		
	August 2022 EV Filing	4220-TE-113	Multi-Family Housing Program	Approved	https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=444518
			EVAAH (Bring Your Own Charger)		
	NSPW Rate Case	4220-UR-126	Public Fast Charging Hubs	Pending	https://apps.psc.wi.gov/ERF/ERFsearch/content/searchResult.aspx?UTIL=4220&CASE=UR&SEQ=126&START=none&END=none&TYPE=none&SERVICE=none&KEY=none&NON=N
			Advisory Services Expansion		
New Mexico (SPS)	SPS 2021-2023 TEP Filing	20-00150-UT	EV Charger and Wiring Rebate	In Market	https://www.xcelenergy.com/company/rates_and_regulations/filings/new_mexico_transportation_electrification_plan
			IQ Charging Rebate		
			Home Charging Service		
			EV Optimization		
			Make-Ready for Public Charging Stations		
			Public Fast Charging Service		
			Advisory Services (Residential, Fleets, Communities)		
Texas (SPS)	Texas Rate Case	54634	EVAAH	Pending	54634_3_1269938.PDF (texas.gov)
			Residential Level 2 Charger Rebate		
			Residential EV Subscription Service		
			Optimize Your Charge		
			Advisory Services (Residential, Commercial, Community)		

The Potential of V2X

Challenges and opportunities for V2X, and how to accelerate market maturity in Xcel Energy's Colorado service territory

Published Q1 2023

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Executive Summary

EV adoption is growing quickly and continues to evolve as the market expands. One advancement seeks to harness the bidirectional charging capability of EV batteries to support a variety of energy needs and services beyond the vehicle, such as powering other EVs, powering a home when the grid goes down, supporting renewables integration, and reducing energy costs.

Bidirectionality has been in R&D for years, with demonstrations as early as 2007 via the University of Delaware.[1] Now, following numerous improvements to EV batteries and charging standards, a growing list of OEMs are enabling bidirectionality for limited purposes. As of November 2022, one OEM—Nissan—has authorized bidirectionality for all purposes in what is known as vehicle-to-everything (V2X).

In Colorado, 78,242 EVs were in use[2] as of February 2023, with 8,647 authorized for V2X capabilities.[3] By 2030, Xcel Energy expects there will be 600,000 EVs in its Colorado service territory. Depending on OEM actions to enable V2X capability, the future EV population may present a significant energy resource opportunity. However, tapping this resource poses challenges. Guidehouse developed this report to provide an outlook for how and when such challenges may be overcome, leveraging interviews with industry experts and data from V2X pilots, demonstrations, and trials.

Guidehouse found that developments in V2X are currently best positioned for vehicle-to-home (V2H) and vehicle-to-building (V2B) deployments when specific conditions are met. Vehicle-to-grid (V2G) has potential, but deployment challenges need to be resolved before it becomes scalable. Key among these challenges are OEM battery degradation concerns, a fragmented market of infrastructure approaches and technical solutions, bottlenecks in the interconnection approval process, and uncertainties about V2G enrollment, participation, and compensation structures. Through its Partnership, Research, and Innovation program, Xcel Energy has shown an interest in helping the V2X ecosystem advance. To that end, Guidehouse has provided several recommendations to Xcel Energy:

- Incentivize V2X adoption to accelerate market development cycles
- Collaborate with equipment providers on demonstrations at the outset of product deployment
- Invest in tools to make interconnection processing more efficient
- Continue to initiate R&D pilots addressing key unknowns of implementation

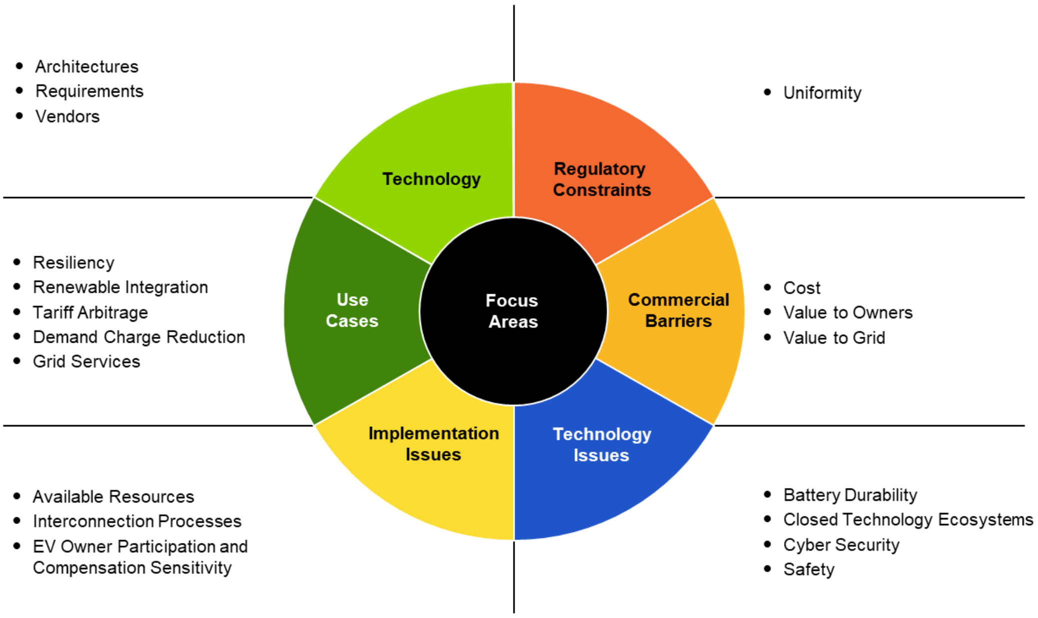
Xcel Energy is currently piloting V2X deployments at numerous customer sites in Colorado to better understand technology functionality; deployment costs; permitting and install processes; interconnection guidelines; vehicle availability; and customer participation, compensation structures, cost savings, and satisfaction. These activities are critical to establishing industry-wide best practices and moving the most advanced forms of V2X toward commercial-ready status.

Introduction

As EVs become more common, emerging developments in vehicle-to-everything (V2X) have the potential to enable EV batteries to be resources for the electric grid. V2X encompasses an ecosystem of technologies that allow EVs to discharge power into electric-powered devices and electrical infrastructure for a variety of purposes, such as charging other EVs, powering a home when the grid goes down, decreasing electricity costs, offsetting requirements for new generation capacity, and increasing renewable energy integration, among others. While V2X holds promise, it is a nascent technology with significant challenges to overcome before it can achieve widespread adoption.

The objective of this report is to provide an overview of the current state of V2X, outline the challenges of widespread adoption, and establish an outlook for how and when the challenges may be overcome. The areas of focus included in this report are represented in Figure 1.

Figure 1: Areas of Focus



(Source: Guidehouse)

To produce this report, Guidehouse interviewed industry experts, including charging equipment manufacturers, EV OEMs, electric utility providers, and V2X case study participants. Guidehouse also identified and analyzed data and insights from published reports covering V2X pilots, demonstrations, and trials. This work is referenced throughout the report.

Guidehouse found that current V2X technologies present clear opportunities for the development of vehicle-to-home (V2H) and vehicle-to-building (V2B) applications under specific conditions—V2H is likely a competitive solution for a portion of the market that both is interested in EVs and values resiliency, and V2B is competitive if property owners can effectively coordinate the availability of multiple EVs. Meanwhile, vehicle-to-grid (V2G) has potential, but significant challenges currently exist for wide-scale deployment.

The challenges for V2G are likely to abate as the emerging market for V2H and V2B applications matures. Key challenges that need to be addressed in this regard are battery degradation concerns; a fragmented market of technological approaches and solutions; bottlenecks in the interconnection approval process; and uncertainties about V2G enrollment, participation, and compensation structures. Meanwhile, cybersecurity is an underlying concern across all V2X applications, as the inherent connectivity required to enable V2X opens a new vector for cyberattacks. Such attacks could, for example, harness the bidirectional capability of V2X-capable EVs to disrupt grid stability or deplete EV batteries.

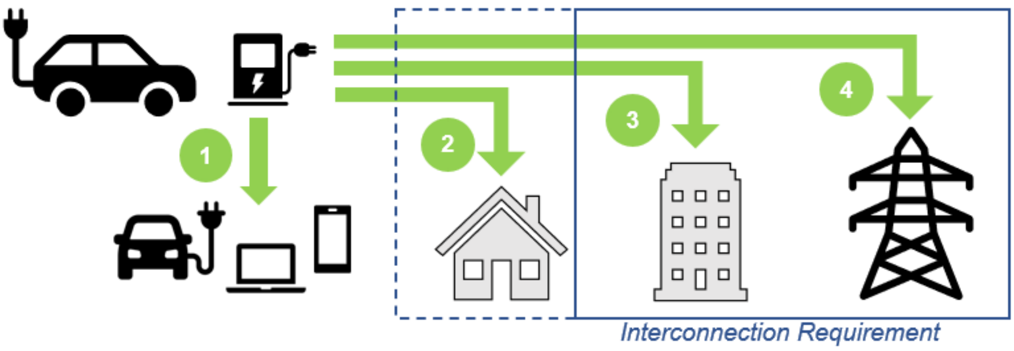
The Basics of V2X

V2X refers to both communications and the two-way energy transfer between an EV and another entity such as the grid, a home, a building, or another vehicle. Each of these applications uses its own abbreviation: V2G, V2H, V2B, and V2L (vehicle-to-load). V2L refers to an EV providing power to any electrical load, including other EVs. Because V2L does not impact the grid, it is not covered in depth in this report. All applications are enabled by vehicles and charging equipment that are designed for bidirectional charging. For V2G, V2H, and V2B, digital platforms are also required to manage energy flows between the grid, the home, or the building.

Digital energy management platforms leverage the communication technologies of the EV energy system—utilities, buildings, charging equipment, and EVs—to schedule and control the flow of electricity. This process is informed by the driver's motive energy requirements—a function of the driver's anticipated time of departure and the battery state of charge—which determines when and for how long an EV's charge may be managed or a battery discharged. This need for the time-of-departure data point means the platform must interface with owners and is dependent on their active participation. Once EV owner participation details are known, then a platform's interface with a building, utility, or grid service market enables it to optimize electricity flow. Upon completion of the EV's participation, the platform is responsible for compensating the EV owner. Most commercial EV charger networking platforms include charge management capabilities; a select few are used for discharge capability, such as those developed by Fermata Energy and Nuvve, as well as FordPass, which can be used to enable the home backup power capability featured on the F-150 Lightning.[4]

Figure 2: V2X Applications Relative to Grid Impact

1. Vehicle-to-Load (V2L): Does not impact the grid
2. Vehicle-to-Home (V2H): Can avoid grid impacts and interconnection requirements
3. Vehicle-to-Building (V2B): Interconnection required
4. Vehicle-to-Grid (V2G): Interconnection required



(Source: Guidehouse)

The most advanced and complex form of V2X is V2G. This is because V2G requires a safe interconnection with the grid that enables utilities to coordinate with EV owners. V2B is less complex, as power is not exported to the grid, yet it still requires coordination with utilities to ensure the system is interconnected safely and does not inadvertently send power to the grid. V2H avoids the interconnection requirement by isolating power flows from the vehicle to the home during power outages.

While V2G is complex, and the challenges significant, it has transformative potential for the grid. For example, the average EV has a battery pack capacity of nearly 70 kWh, and the average driver in the US would likely consume nearly 13 kWh a day[5] to power the average daily travel of 45 miles.[6] If the EV was connected to a power supply between 208 V and 240 V (common for Level 2 AC charging), the daily motive energy requirement could be replenished within 1.5 to 2 hours. This leaves a large portion of the day and night when the energy storage potential of the EV could be tapped for grid purposes.

If one out of every five vehicles in Xcel Energy's Colorado service territory is electric by 2030 (assumed in Xcel Energy's net-zero energy vision[7]), there would be approximately 600,000 EVs. Assuming 70 kWh per EV, this amounts to 42 GWh of energy storage that could potentially absorb excess generation capacity, service high demand periods, increase renewable energy integration, or reduce needs for fossil power. Some studies suggest that with enough participation, V2G could even reduce the need to build future generation capacity.[8] Businesses, schools, and homes could also use V2B and V2H capabilities to reduce peak demand and its costs and keep critical electric loads up and running during outages. While these estimates are encouraging, specific challenges must be addressed before V2X can achieve its potential:

- **More OEMs need to enable V2X capability.** Few OEMs have enabled V2X capability on the EVs they have deployed, and only one, Nissan, has enabled V2X capability beyond V2H.[9]

- **More bidirectional charger options are needed.** The market for bidirectional chargers is fragmented between three distinct infrastructure approaches, each with limited UL-listed solutions.

- **Interconnection approval processes need to become more efficient.** Many interconnection reviews rely on manual processes that have trouble adapting to the large-scale request volumes that consumer markets present.

- **More data on V2G program metrics needs to be developed.** Too few V2G projects have taken place to provide solid data on key metrics (enrollment rates, participation rates, and compensation structures) on which to base a V2G program.

The challenges above are likely to abate as several market trends materialize. Primary among them is OEM adoption of V2X use under warranty provisions. Momentum is certainly growing in this direction as more and more OEMs are authorizing use of V2L and V2H capabilities.[10] Additionally, OEMs could authorize thousands of EVs already deployed via over-the-air updates. While this momentum is encouraging, OEM uncertainties regarding the impact of unlimited V2X use on battery degradation may moderate the trend.

EV batteries degrade as a function of use and climate. For example, full and fast battery cycling at extreme ambient temperatures is generally understood to degrade batteries the quickest. Under these conditions, most EV batteries are rated to last at least 2,000 cycles.[11] However, this scenario is rare because battery management systems typically prevent full discharging and moderate charge rates when the battery state of charge nears 100%. Additionally, EV owners generally prefer gentle charging behaviors that support durability—frequent use of slow chargers rather than periodic use of fast charging. As such, predictive modeling indicates EV batteries should last longer than the typical 8-year/100,000-mile warranty provided by OEMs.[12] However, V2X uses likely accelerate degradation. The extent is not yet well understood by OEMs, which are therefore hesitant to include all V2X uses within warranties.

Nevertheless, OEMs are moving toward V2X authorization, with the volume of V2L- and V2H-capable vehicles poised for growth. This is likely to create a market development cycle that can 1) support consolidation of technological approaches with many bidirectional charger solutions, 2) develop and spread best practices for interconnection approval processing, and 3) generate real-world data that can help utilities better understand the costs and values of V2G.

V2X Applications Are Emerging

The potential use cases for V2X are resiliency, renewables integration, tariff arbitrage, demand charge reductions, and grid services. These are not accessible across all V2X applications, and each application has a primary use case, as demonstrated in Table 1. While there are many use cases, the technology and market status for any use case is currently limited to niche market commercialization and R&D projects. The following sections provide an overview of each application.

Table 1: Common Current Use Cases for Different V2X Applications

Application	Resiliency	Renewables Integration	Tariff Arbitrage	Demand Charge Reductions	Grid Services
V2H	**✓**	✓	✓		
V2B	✓	✓	✓	**✓**	
V2G	✓	✓			**✓**

Use case not applicable ☐
Use case applicable ✓
Primary use case **✓**

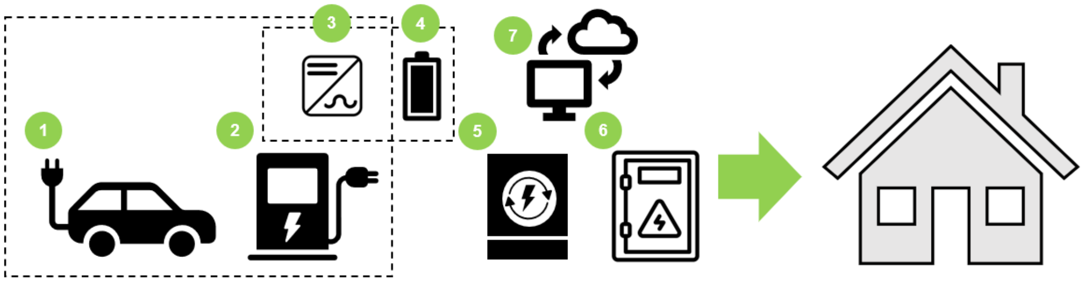
(Source: Guidehouse)

V2H Is a Cost-Competitive Resiliency Solution for a Niche Market

Emergency backup power for residential homes is the primary use case for V2H. Energy arbitrage and increasing use of excess rooftop solar generation are also possible but would require interconnection approvals to ensure that potential net power flows across the meter do not negatively impact the grid. As such, resiliency is the main appeal until interconnection issues are addressed.

Figure 3: V2H System Requirements

1. V2X-capable EV
2. Bidirectional charger
3. Inverter: Could be in vehicle, in charger, or in home energy management system
4. Blackstart battery: Provides power until main energy assets are online
5. Disconnect switch: Prevents back-feeding during outages
6. Critical load panel: Prioritizes load toward essential appliances and circuits
7. Digital energy management platform: Controls energy flows between vehicle and home



(Source: Guidehouse)

The only V2H solution on the market is provided through a partnership between Ford and Sunrun designed specifically for the Ford F-150 Lightning. Ford provides the bidirectional charger, while Sunrun provides a home integration system consisting of the system's required inverter, a disconnect switch, and a blackstart battery. Ford and Sunrun's deployment indicates that total cost for V2H deployment likely approaches $11,000, with costs split roughly evenly between equipment and installation. As shown in Table 2, this produces a premium over the standard residential L2 charger deployment of **$8,594 to $9,005**.

Table 2: V2H Deployment Cost Premium

Deployment Cost Component[13]	Ford-Sunrun V2H Solution	L2 Home Charger[14]
Charger	$1,310[15]	$380–$689
Power Management Equipment	$3,895[16]	NA
Equipment Total	$5,205	$380–$689
Bundle: Power Management Equipment and Install + Charger Install	$9,400	NA
Install Cost (Charger + Bundle – Equipment Total)	$5,505	$1,325–$1,427
Deployment Total	**$10,710**	**$1,705–$2,116**
V2H Premium	**$8,594–$9,005**	

(Source: Guidehouse)

Figure 4: Ford-Sunrun Illustration of V2H System with Rooftop Solar

(Photo courtesy of Sunrun)

Outside of Ford's V2H deployment, no other solutions have yet been commercialized. Ford has indicated that deployment monitoring is ongoing but no data on adoption is yet available. Additionally, Ford interviewees noted they are taking a "crawl, walk, run" approach that begins with home backup power. Ford has also begun internal testing on other V2X capabilities, including a pilot V2G program with PG&E,[17] but has not provided further details.

Industry standards are a key challenge for V2H. Current bidirectional chargers have compatibility limitations with upcoming V2X-capable EVs. For example, Ford's system can only work with the Ford F-150 Lightning. Similarly, Lucid's bidirectional charger is only compatible with Lucid vehicles, and current bidirectional Fermata chargers are only compatible with CHAdeMO connections. These types of compatibility issues lock customers into specific technology ecosystems, posing a risk of asset stranding if the charger outlasts the EV or vice versa.

In terms of capability, V2H systems are more than capable of providing power for temporary outages, but not for sustained ones. For example, if an extended-range F-150 Lightning was fully charged, Ford and Sunrun estimate it could support a home's power needs for three days at an average of 30 kWh per day[18] while still retaining some energy in the battery for driving. This is substantial; however, for many customers, the value of such resiliency over the cost of a standard home charger may not be equivalent to the premium paid. A study by PG&E indicated this may be the case, as it concluded that customer willingness to pay for a V2H system was lower than the estimated cost.[19]

While costs for bidirectional chargers are likely to decline, other costs for power management equipment and installations are unlikely to see similar declines because these technologies and services are mature. This likely limits mass-market adoption unless consumers value resiliency more. Until then, **V2H is likely competitive for a portion of the market that is interested in EVs and sufficiently values resiliency**, as the V2H system premium is competitive against fossil fuel-powered whole home generators[20] and battery backup systems.[21]

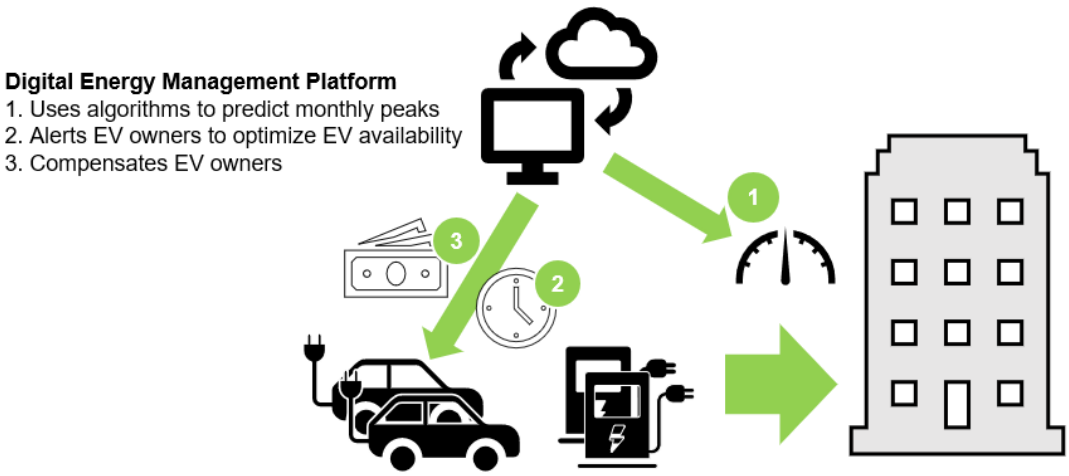
Currently, Xcel Energy is piloting a limited V2H deployment at three customer sites. During this pilot, Xcel Energy will be testing the backup power capability and limitations of EVs for residential homes. Additionally, the pilot seeks to better understand the permitting and installation processes and gauge performance and customer satisfaction for V2H systems.

V2B Costs and EV Scheduling Challenges Limit Adoption Potential

The primary V2B use cases are energy cost savings via demand charge reductions and tariff arbitrage. Like V2H, V2B also has potential to take advantage of onsite renewable power and be a resiliency resource. Time-of-use rates and demand charges are distinct pricing components common within commercial property utility rate structures. Coordinating vehicle batteries to charge during off-peak times and to discharge at peak times increases the property's utilization of off-peak rates and can also reduce the monthly peak.

As the primary V2B use cases require EVs to back-feed building infrastructure while it is also being powered by the grid, an interconnection study must accompany deployment to ensure net power flow across the meter does not negatively impact the grid. Beyond this study, V2B functionality needs the same components as a V2H system. However, the digital energy management platform will likely require more advanced functions, as demonstrated in Figure 5.

Figure 5: V2B System Requirements



(Source: Guidehouse)

V2B has been explored through R&D projects focusing on energy cost reductions via tariff arbitrage and demand charge reductions. In Colorado, V2B R&D projects have resulted in monthly energy cost savings of around $240 per month, as demonstrated in Table 3.

Table 3: Examples of V2B Peak Shaving Project Results

Project	Location	Chargers	Months	Total Savings	Savings/ Month
Alliance Center/Colorado CarShare[22]	Colorado	1	4	$950	$238
Boulder Recreation Center[23]	Colorado	1	12	$2,963	$247
Electric Frog/Burrillville Wastewater[24]	New York	1	1	$222	$222[25]
Roanoke Electric Cooperative[26]	Virginia	1	2	$235	$118

(Source: Guidehouse)

Figure 6: Nissan Leaf with Fermata Bidirectional Charger at Boulder Recreation Center

(Photo courtesy of City of Boulder)

However, achieving the savings comes with a high cost. Figures provided to Guidehouse and Xcel Energy indicate that commercial L2 DC bidirectional chargers cost approximately $10,000, additional power management equipment costs approximately $8,000, and install costs range from $10,000 to $25,000—not including costs associated with completing interconnection approvals, which vary depending on site-specific factors. As demonstrated in Table 4, these costs translate to simple payback periods of 6 to 12 years.

Table 4: V2B Simple Payback Analysis in Colorado

Cost Component	V2B ($/charger)	Commercial L2 ($/charger)[27]	V2B Premium ($/charger)
Charger	$10,000	$4,900–$7,210	$2,790–$5,100
Power Management Equipment + Install	$18,000–$33,000	$4,173	$13,827–$28,827
Deployment Total	**$28,000–$43,000**	**$9,073–$11,383**	**$16,617–$33,927**
Annual V2B Savings	**$2,900**	**NA**	**$2,900**
Simple Payback (years)			**6–12**

(Source: Guidehouse)

Notably, the high costs are associated with three-phase electrical infrastructure requirements, increasing costs for both power management and installs. Expanded availability of single-phase solutions would likely see power management equipment and install costs fall significantly. Additionally, as a building may host multiple chargers and EVs, deployments of more than one bidirectional charger would likely realize some scale benefits and a faster payback. Government financial assistance and agreements with equipment providers can also greatly reduce site deployment costs. For example, one pilot program participant reduced overall upfront costs to $10,000[28] via grants and an agreement to share operational cost savings with the V2B provider.

An additional challenge to achieving energy cost savings is managing vehicle availability. Digital platforms can dispatch EVs in time with the building's peak load, but only if the EVs are plugged in. Ensuring availability is a manual task, as was noted by a V2B pilot participant.[29] This means property staff must be aware of the V2B strategy and manage EVs accordingly to attain monthly savings. There may be opportunities where peak loads coincidentally align with EV availability. This will, however, vary case by case and may be difficult for property owners to understand. As such, achieving a payback ahead of an assumed 10-year charger lifespan is uncertain.[30] Thus, **V2B is likely to serve niche markets** until deployment costs decline.

Currently, Xcel Energy is piloting a limited V2B deployment at two customer sites. During this pilot, Xcel Energy will test V2B technologies to understand the costs to deploy and operate, gauge vehicle availability and cost savings, and evaluate other potential deployments.

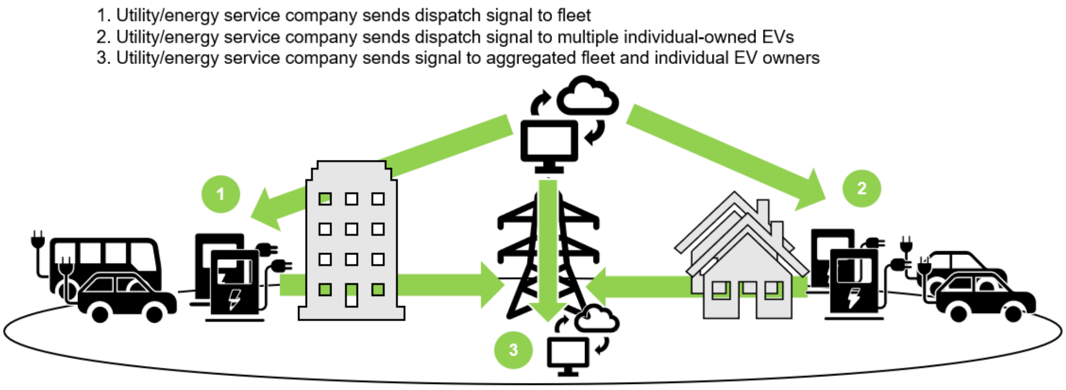
V2G Has Potential, but Other V2X Applications Need to Develop First

V2G has many potential uses, including reducing peak demand on a grid-wide basis, integrating renewables, and providing grid services such as frequency and voltage regulation, among others. As the grid becomes more intelligent and decentralized, V2G could also be used for other localized services to reduce grid management costs.

The benefit of V2G to EV owners is reduced electricity cost. For grid operators, V2G could reduce grid management costs and make the grid more greenhouse gas (GHG) efficient. This would occur if the process of aggregating V2G assets and compensating owners for participation fell below the costs of using other, more centralized assets commonly used for grid services like natural gas peaker plants or dedicated battery energy storage systems. Use of V2G assets, alongside energy storage systems, would also displace use of GHG-intense assets and thus help reduce GHG content on the grid.

V2G requirements are effectively the same as those for V2B. The difference, however, is that the digital energy management platform leverages connectivity to utility programs or energy markets to inform charge/discharge scheduling. Depending on where EVs are located, these programs or markets may not be accessible. Where utilities and energy markets are accessible, V2G R&D activities have been accomplished leveraging EVs at homes and buildings. As demonstrated in Figure 7, V2G programs can be managed by utilities or energy service companies, both of which use grid data to send charge/discharge signals to EVs and compensate owners according to participation rates.

Figure 7: Approaches to V2G Implementation



(Source: Guidehouse)

R&D for home-based V2G is rare; however, activities in the UK have aggregated upwards of 400 home-based V2G deployments.[31] Development of V2G in the rest of Europe and in the US has focused more on commercial fleets, which are generally more attractive for V2G given larger and more reliable energy storage potential per interconnection. For example, electric school buses have large batteries, leverage centralized depots for maintenance and refueling, have predictable routes and energy requirements, and have attractive availability for stationary energy storage during summer electrical usage peaks. As such, the costs to activate a fleet of electric school buses for V2G is proportionally much less than to do so for a single home or V2X-capable vehicle. Additionally, reaching minimum capacity requirements for energy market participation is much easier than aggregating hundreds of individually owned EVs. In the US, V2G demonstrations leveraging school buses are increasingly common, as shown in Table 5.

Table 5: School Bus V2G Projects in the US

Location	Bus OEM	Buses	Project Start
Torrance, California[32]	Blue Bird	6	2017
Multiple school districts, Virginia[33]	Thomas Built	50	2019
White Plains, New York[34]	Lion Electric	3	2020
Pekin/Peoria, Illinois[35]	Blue Bird	2	2021
Ann Arbor/Roseville, Michigan[36]	Thomas Built	6	2021
Beverly, Massachusetts[37]	Thomas Built	1	2021
El Cajon, California[38]	Lion Electric	6	2022
Durango, Colorado[39]	Blue Bird	1	2022
Ramona, California[40]	Blue Bird	8	2022
South Burlington, Vermont[41]	Thomas Built	4	2022

(Source: Guidehouse)

Figure 8: Blue Bird Electric School Bus Connected to Nuvve Bidirectional Charger in Durango, CO

(Photo courtesy of Nuvve Holding Corp.)

Lessons from the school bus V2G projects are ongoing; however, early indications suggest that V2G has had little impact on the availability of buses for their primary transportation use[42] and can play a meaningful role in reducing total cost of ownership.[43] Projects have also identified efficiency losses of 15% tied to the additional power conversion and parasitic draws of V2G systems, and battery degradation rates from V2G have been equivalent to degradation under motive power conditions. Findings do not yet clearly indicate the financial viability of V2G.

A key challenge for V2G will be clearly achieving a positive cost-benefit ratio. This is because the conditions of V2G are highly variable, depending on the value of grid services in a utility service territory or electricity market compared with the cost of financing equipment installation and incentivizing sufficient EV owner participation levels.

The value of grid services is not consistent geographically or temporally. Geographically, grids with high penetration of intermittent renewables (solar, wind) likely value distributed energy resources (DER) more than grids with more reliable renewables (hydro) or more reliable low carbon generation sources (nuclear). Temporally, the value of grid services fluctuates over the course of the day, often a function of the alignment of grid demand and generation profiles. As such, times when DER values are high may not coincide with high availability of V2G-capable EVs.

To evaluate the financial viability of a V2G deployment in Xcel Energy's Colorado service territory, Guidehouse assessed the simple payback for a 60 kW DC V2G charger deployment of an electric school bus using Xcel Energy's Interruptible Service Option Credit.[44] As demonstrated in Table 6, simple payback is not achieved until year 13, longer than an assumed 10-year charger lifespan.[45]

Table 6: V2G Simple Payback Analysis in Xcel Energy's Colorado Service Territory

Cost Component	V2G ($/charger)	DC Fast Charger ($/charger)	V2G Premium ($/charger)
Charger	$65,650	$39,390	$26,260
Power Management Equipment + Install	$129,952	$103,962	$25,990
Deployment Total	**$195,602**	**$143,352**	**$52,250**
V2G Revenue ($/year)	**$4,042**	**NA**	**$4,042**
Simple Payback (years)			**13**

(Source: Guidehouse)

The result is not encouraging—deployment costs need to come down to speed payback. Beyond electric school buses, V2G opportunities are severely limited by a lack of vehicle and charger options. For example, the only V2G-authorized light duty vehicle is the Nissan Leaf, and the only UL-listed bidirectional charger that supports the Leaf requires three-phase electrical infrastructure. This makes the technology prohibitively expensive to install in a vast number of residential and commercial scenarios. Hence, for an aggregator or utility to develop **a wide-scale V2G program today would be premature**.

Currently, Xcel Energy is piloting a limited V2G deployment at two customer sites. During this demonstration, Xcel Energy will test the availability and functionality of electric school buses for use as a grid resource. Additionally, Xcel Energy seeks to better understand the system components and costs, develop interconnection guidelines, and gain insights into customer participation and compensation structures.

The Road toward V2G

While development of a wide-scale V2G program today is premature, it may be feasible in the not-too-distant future. Emerging V2X technologies show promise under specific, limited conditions for both V2H and V2B that likely support a small but growing volume of V2X-capable EVs. As these volumes grow, industry stakeholders need to address battery degradation concerns, a lack of technology solutions, complicated interconnection approval processes, and participation rate uncertainties to make wide-scale V2G program development possible.

Battery Degradation Concerns Need to Diminish

Repeated cycling of an EV's battery likely contributes to degradation, which affects the depreciation of the EV. Understanding the relationship between battery charging/discharging cycles and depreciation is key to OEMs authorizing V2X use cases, warranty guidance, and appropriate compensation rates for EV owners.

The rate of degradation depends on numerous factors; generally, however, the deeper and faster the discharge, the greater the degradation. Notably, shallow, gentle cycling may have marginal to beneficial impacts, as was found in a study published by the Royal Society of Chemistry.[46] The study modeled V2G battery degradation and determined that the energy cost savings likely outweigh the depreciation impact. While this finding is encouraging, more real-world data is likely necessary for each V2X use case to enable widespread OEM authorization and warranty incorporation. To this end, R&D activities are continuously evaluating battery degradation impacts. Additionally, innovations in battery and charging technologies are also diminishing the degradation threat and its financial impacts.

The momentum of the overall EV market is driving significant investments in battery innovations. From a V2X perspective, the most relevant and impactful innovations would see a market shift away from nickel-rich battery chemistries toward alternate, cheaper, and more durable chemistries like lithium iron phosphate (LFP), as well as toward new, more durable cell architectures like solid-state. LFP adoption is growing now, as it is the most common EV battery technology in China and is emerging in the US and Europe. LFP is considered to be far more durable and stable than nickel-rich chemistries, with the ability to withstand multiple thousands of charge cycles with minimal degradation.[47]

However, with minimal deployment of V2X today and LFP's lower energy density compared with nickel-rich cells, the real driver for wide adoption of LFP is the 30% to 40% lower cost. A shift away from current modular battery pack architectures to cell-to-pack (a.k.a. structural pack) architectures is leading to a doubling of the fill ratio of active cell material, overcoming the lower energy density of LFP.

Solid-state technology is in R&D phases, with the first real-world deployments expected to occur mid-decade in non-plug-in hybrids. Successful testing under the hybrid use case and successful scaling of the manufacturing process would likely lead to deployment within EVs near the end of the decade. Beyond these innovations, durability improvements are also being explored through technologies that manage electron flow and temperature. Additionally, significant investments are driving innovations that indirectly mitigate degradation threats by reducing battery manufacturing costs and decreasing battery depreciation. In addition to the shift to cell-to-pack architectures that simplify the pack, there are numerous efforts to commercialize dry electrode coating, which would bring manufacturing cost reductions of 25% or more regardless of the chemistry.

As a sign of this trend, light duty OEMs are moving toward V2X and V2L adoption.[48] Notably, however, the full suite of V2X capabilities is only authorized for the Nissan Leaf.[49] Among commercial vehicle markets, V2G capability has focused on the school bus market, where most suppliers—Thomas Built, Blue Bird, IC Bus, Lion Electric, Trans Tech, Collins, Starcraft, and BYD—now offer V2G as an option or as standard.[50]

Technological Approaches Need to Consolidate

The suite of bidirectional chargers available now have limited compatibility with V2X-capable EVs. This is a risk for consumers, as it locks them into closed technology ecosystems. As the market matures, more V2X infrastructure solutions are likely to be made compatible with more V2X-capable EVs, allowing customers to mix and match solutions as they see fit. Currently three distinct architectures are used by OEMs, as shown in Table 7. These architectures are distinguished by the inverter's location.

Table 7: V2X System Architectures

Inverter Location	Charger Type	Pros	Cons	Market Examples
EV	AC	Lower charger cost	Increased EV cost Limited discharge	Lucid Air (J1772)
Charger	DC	Lower EV cost	Higher charger cost	Nissan Leaf (CHAdeMO)
Other equipment	DC	May benefit onsite generation and storage Lower charger cost	Higher overall infrastructure costs if no onsite generation and storage opportunity	Ford F-150 Lightning (CCS)

(Source: Guidehouse)

An additional distinction among the architectures is connection standard. The Combined Charging System (CCS) has emerged as the leading fast charge connector in the US and Europe for all non-Tesla EVs. However, the competing CHAdeMO standard remains relevant in V2X because it has long defined requirements for V2G communications. Only recently has the Charging Interface Initiative (CharIN), which defines requirements for CCS-related standards, published certificate policies[51] for V2G communication protocols. This is encouraging and will help consolidate the market toward a more uniform charging solution. However, the market is fragmented, and UL-listed supply for any given approach is limited.[52] Before wide-scale V2G program development can occur, greater technological consolidation is needed alongside increased product availability. Notably, Tesla's North American Charging Standard is the dominant standard in terms of EVs in use and public DC fast charger deployments.[53] While the standard is now open for adoption by other EV makers, it is currently only used by Tesla.

Interconnection Approvals Need to Be More Efficient

Interconnection issues are a challenge for V2G. To quote a report commissioned by UK Power Networks and Innovate UK, “Onerous interconnection requirements were repeatedly flagged in interviews (Grid Motion, France; JumpSMARTMAui, USA; Parker, Denmark).” [54] Furthermore, the distributed nature of V2X is a challenge to a rigid regulatory structure built to serve centralized energy distribution. This is summarized well in a report by Kaluza, which states, “As is often the case, policy and regulatory change tends to lag behind technological innovation, and the same is true in the case of V2X.”[55]

The interconnection process is important to maintaining safe and reliable grid operations. It is, however, a bottleneck. As illustrated by challenges observed with residential solar installations, each install requires the utility to complete an interconnection study to ensure that back-feeding the grid does not create negative impacts or safety risks to local distribution systems. These studies are not easily or quickly completed, and as market adoption increases, they create challenging backlogs for utilities.

Utilities are seeking to address this complication via automation. For example, the National Renewable Energy Laboratory (NREL) partnered with the Sacramento Municipal Utility District in California to create an automated interconnection assessment tool called PRECISE. Since the tool launched in February 2022, it is reported to have processed an average of 13 applications per day (as of November 2022).[56] NREL states that the tool’s potential on a daily basis is in the hundreds. If the tool proves successful, it will be an encouraging development for the industry that could mitigate current and future interconnection challenges.

Participation Rates Need to Be Better Understood

The value of V2G to the grid depends on when EVs are available and what level of incentive is required to stoke participation. Potential coincident periods of low vehicle availability and high electricity demand could mean most EVs are unavailable for the highest value times. Additionally, even if EVs are available, they may not participate given any number of circumstances.

Better understanding EV availability and participation relative to incentive level is critical to determining how many V2G-capable EVs are needed within a geographic area for a utility or aggregator to meet minimum requirements for grid service markets or targets for utility programs. The first step in this process is gauging physical vehicle availability against grid needs. This may be modeled using data on vehicle travel and EV charging behaviors and then compared against data on renewable generation, peak demand, or grid service markets. The output of this exercise is likely to vary by utility.

Physical vehicle availability must be significantly greater than the minimum capacity requirement. This is because enrollment within a given DER program likely captures a small minority of the overall resource base, as demonstrated in Table 8.

Table 8: Enrollment Rates in Similar Opt-In DER Programs

Location[57]	Program	Incentive	Program Enrollment Rate
UK	Kaluza V2G trial	$41/month (average)	14%
Colorado	Xcel Energy AC Rewards	$50 rebate, $100 sign-up, $25/year	10%
Colorado	Xcel Energy Charging Perks	$100 sign-up, $100/year	1%
Colorado	Xcel Energy Optimize Your Charge	$50/year	3.3%
Mountain States	Retail demand response programs	Varies by market specific factors	12%
US	Retail demand response programs	Varies by market specific factors	8%

(Source: Guidehouse)

The enrollment rate only informs part of the participation picture. Actual program participation will depend on EV owner choices, as an enrolled, plugged-in participant may choose to defer participation. The rate at which enrollees will participate likely depends on what incentives program managers provide. In this regard, there is little real-world data. As the market develops, R&D projects will be key to better understanding owner sensitivity and thereby gauging the appropriate market volumes required to deploy wide-scale V2G programs.

Timing V2G Potential in Xcel Energy's Colorado Service Territory

For a wide-scale V2G program to be viable, a minimum capacity threshold defined for a specific grid service within a specific geography must be determined. This is likely to vary by geography for a variety of reasons. In geographies covered by independent system operators (ISOs) and regional transmission organizations (RTOs), the minimum capacity threshold for electric storage participation in capacity, energy, and ancillary markets is regulated by the Federal Energy Regulatory Commission (FERC) at 100 kW.[58] While Colorado is not included within an ISO/RTO market, this regulation may provide an indicative value from which to evaluate the readiness of V2G in Xcel Energy's Colorado service territory.

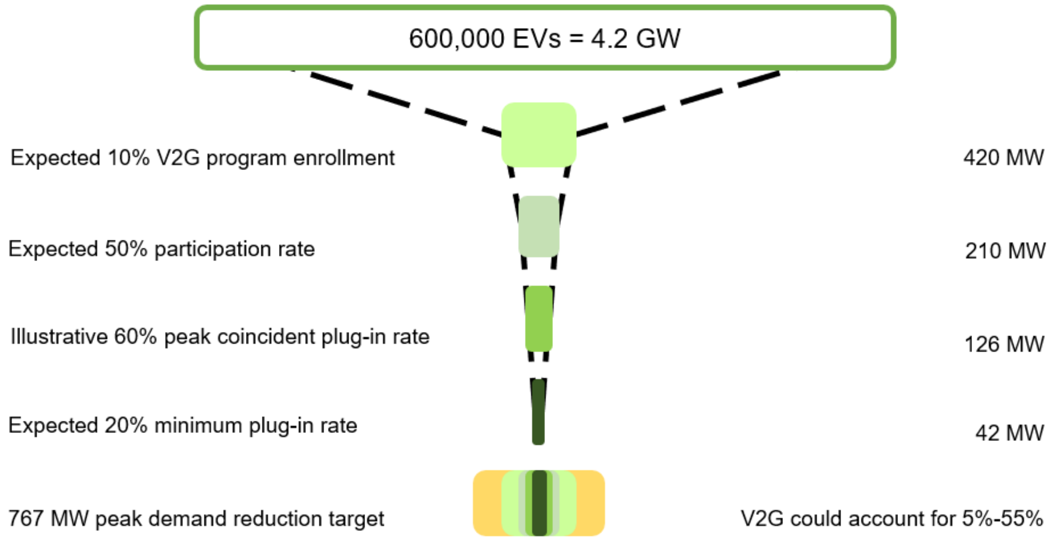
Assuming that each V2G-capable EV can provide an average of 7 kW when plugged in, at least 14 need to be plugged in and ready to participate at any given time. This may be easy to achieve at night with a few vehicles, but it is likely very challenging during the day when vehicles are most active. As such, a utility or aggregator would need to enroll greater volumes of EVs to maintain a diverse body of V2G resources that would maintain a consistent 100 kW minimum. R&D projects in the UK[59] and Massachusetts[60] indicate at least five EVs need to be enrolled, so that one may be plugged in at any given time. The Massachusetts project further indicates that at least two need to be plugged in to reliably assume that one participates. Hence, at least 10 EVs would need to be enrolled so that one is always ready and available to participate. Meeting the 100 kW minimum would therefore require enrolling at least 143 V2G-capable EVs. Based on enrollment rate data, demonstrated in Table 8, Guidehouse assumes Xcel Energy could enroll 10% of a V2G-capable EV fleet within its service territory. This would mean 1,430 V2G-capable EVs would need to be in use in Xcel Energy's service territory.

Currently, there are just under 6,400 V2G-capable EVs in the service territory (11.6% of all EVs).[61] These are all Nissan Leafs, as the Ford F-150 Lightning is not yet authorized for V2G. It is possible that the Ford F-150 Lightning could become V2G capable via over-the-air updates; this is true of many EVs, and as such, the number of V2G-capable EVs could surge. However, OEM plans in this regard are not clear, and few OEMs have indicated an update is coming beyond V2L or V2H. Regardless, under the assumed logic, a V2G program could enroll 640 V2G-capable EVs, of which 64 could be assumed plugged in and providing nearly 450 kW at all times, thus exceeding the 100 kW minimum capacity requirement.

This would be the case if bidirectional charging solutions leveraging residential single-phase electrical infrastructure existed. If it can be assumed that such solutions will emerge, then the V2G picture will look different by 2030. For example, Xcel Energy expects the EV fleet within its territory to grow over 10 times, such that 600,000 EVs would be in use. If the current share of V2G-capable EVs to overall EVs (11.6%) remained the same, Xcel Energy could expect a V2G program to produce close to 4.9 MW at any given time.

Alternatively, if OEMs authorized V2G such that it was standard on all EVs, a V2G program could expect to aggregate at least 42 MW of capacity at any given time. As of November 2022, Xcel Energy has proposed a 2030 demand response goal of 767 MW for its Colorado service territory.[62] Depending on the coincidence of vehicle availability with peak demand, the V2G resource base could make a significant contribution to meeting the 700 MW demand response target by 2030. For example, if 60% of the V2G-capable EVs were available during the system peak, V2G could support 18% (126 MW) of the target, as demonstrated in Figure 9.

Figure 9: 2030 V2G Potential in Xcel Energy's Colorado Service Territory



(Source: Guidehouse)

Ways to Accelerate the Market

Developments in V2X technologies show promise for V2H, V2B, and V2G. There are many challenges for the technology ecosystem to overcome, but there are also clear business cases for deployment of V2H and V2B now that could generate positive market development cycles to enable V2G later. Therefore, Guidehouse recommends:

- **Incentives** for bidirectional chargers, and the installation costs thereof, to accelerate adoption and market development cycles. Encouraging this is necessary for industry standards to consolidate and more products to enter the market. A focus on V2H and V2B deployments for resiliency purposes, rather than use cases that would require interconnection studies, is suggested to avoid current processing complications. Additionally, incentive design must be mindful of the potential to increase inequity in the market. In this regard, focusing on support for public transit systems such as school busing is recommended.

- **Collaboration** with equipment providers on demonstrations at the outset of product deployment. Early V2X adoption will yield data about vehicle usage and customer sentiment that Xcel Energy needs to access so it can better understand the technologies and the behaviors of the customers that use them.

- **Investment** in tools to make interconnection processing more efficient. While targeted investments in V2X technologies will help the market development cycle churn, these investments may not result in a viable V2G resource if interconnection processing is not more efficient. Xcel Energy should position itself at the forefront of market developments in this regard and exploit opportunities to test developers' tools. This could support near-term challenges with rooftop solar interconnection processing and lay the foundation for streamlined V2G interconnections in the future.

- **R&D pilots** to launch projects targeted at addressing key unknowns of V2G implementation such as enrollment rates, EV availability relative to grid values, and owner participation relative to incentive levels. Better understanding these variables will improve Xcel Energy's ability to plan and time potential wide-scale V2G rollouts.

Appendix 1: Interview Notes

Interview #1

Industry: Nonprofit
Organizational Focus: Demonstrate sustainable solutions to climate change issues using the built environment
V2X Experience:

- Organization saw potential intersection between V2X and its physical building
- Coordinated demonstration with EV supply equipment (EVSE) manufacturer for a V2B pilot focused on maximizing energy efficiency to vet battery technology
- Pilot outcome:
    - Utilizing car battery to reduce utility bill with demand charge structure (5% savings)
    - Developed economic model with project partners to ensure there was not a big payback period for initial investment
    - Next step is planning to reach out to Xcel Energy to explore opportunities for tariff structure and use it as a grid resource

V2X Applications and Use Cases:

- Primary use case is reduced demand charges by using the car battery

Technical Challenges of V2X Adoption:

- Very manual process right now to set up, and limitations in identifying which cars can be utilized
- Challenges balancing personnel with anticipating when the car can be connected to the building to participate in demand events
- Predictive algorithms and AI may alleviate the need for manual scheduling. Need to more gracefully managing car availability based on grid signals.

Financial Challenges of V2X Adoption:

- V2X pilot was only cost-favorable due to a grant that covered the installation of car charger
- Total upfront costs are $10,000 including ~$1,000-$2,000 for electrical infrastructure

Incentivizing Adoption of V2X:

- Utility is a big driver for creating a win-win incentive for building owner that aligns with existing billing
- In terms of making it happen, there is a deployment of infrastructure, and shifting infrastructure is critical
- Car partnership and utilizing car battery for voiding warranting (car manufacturers)
- Adoption will follow once there are rate structures that make economic sense

Assessing Value for V2X:

- Simple cost-benefit analysis
    - Calculate the upfront cost and potential lease/cost for car
    - Identify payback period and ROI
    - Organization is willing to take on some risk, but need assurance of lowering bill credit
    - Resiliency is not a primary benefit for this location

Interview #2

Industry: EVSE
Organizational Focus: Design, supply, and operate technology that integrates EVs with buildings and the electricity grid
V2X Experience:

- Organization provides V2G-capable charging software and hardware that empowers EV owners to earn money and protect the environment while contributing to a more resilient and renewable-energy-based power grid
- Currently operates commercially available Nissan Leaf V2G deployments
- Currently functioning as an aggregator, but can help coordinate with the utility to serve nodal needs

Pilot Programs:

- Behind-the-meter (BTM) demand side management project (reducing electric costs by at least the cost of a Nissan Leaf lease—paying for itself)
- Demand response: One customer used a 15 kW charger, which earned $4,300 per year. This pilot was designed to help them understand optimization of response capabilities.

Growth of V2X Market:

- More V2G-compatible cars. Nissan Leaf now (and Mitsubishi Outlander), expecting a dozen more models to be compatible by 2023.
- Bidirectional chargers. Can be onboard or offboard, AC or DC. Organizational preference for offboard DC with a utility partner program.
- Software platform to manage power flow and optimize revenue and remaining charge for duty cycle. Must also work with different communication protocols: OCCP, Open ADR, Open FMB.

Technical Challenges of V2X:

- All L2 chargers will need to be replaced if there is onboard AC or DC charging
- CCS, common in Electrify America, does not have certification; nothing to certify

Industry Standards and Government Regulations for V2X:

- Xcel Energy can accommodate mobile storage; this is not true for all utilities, and customers may be limited to stationary only
- CCS chargers were heavily adopted and expected to be standard, so a lot of vehicles were built with this
- Communication channels:
  - Data sent up to the utility
  - Data sent back to the vehicle
- Organization currently use CHAdeMO connectors, which are certified for V2G
- Interested customers need to begin planning for the correct vehicle charger type
- Work with industry partners and regulators to ensure the right communication protocols are being used to streamline communication to chargers—whether it is done by an aggregator or the utility

Interview #3

Industry: Transportation
Organizational Focus: Provides school bus services, working with districts to carry students to and from school
V2X Experience:

- Currently doing a pilot using school buses for full-scale V2G
- Separate pilot ongoing for V2B using separate school bus model
- Full-scale fleet pilot involving 20 buses
- Goal of organization is to be a trusted partner for the utility to understand load considerations as more vehicles are added to the grid market

Growth of V2X Market:

- Lots of discussions are occurring in the space around microgrids
- They recognize that the switch to EV is happening, but the pace is not yet possible to predict based on the uncertainty of incentive levels and the speed of cost reductions with manufacturing scale
- There will also need to be a lot of investment done in transmission and distribution and BTM

Financial Challenges of V2X Adoption:

- Organization will go from being a small electricity consumer to an extremely large one and wants to understand how utilities will want them to cover infrastructure investments
- They will need to plan far ahead of time to plan scaling from 0 ESB, to 1-10, to 10-50, to 50-250

Technical Challenges to V2X Adoption:

- Standardization of communication between vehicle, grid, and utility as well as policy
- Policy needs to be ironed out for how the ISOs control the power from the buses
- Dealing with seven different battery geometries, which can make planning complex
- Vehicle second life: There may still be value in the drivetrain and battery for electric school buses

Interview #4

Industry: Automotive manufacturer
Organizational Focus: Manufacture and sell automobiles with several electric models of cars/crossovers and trucks
V2X Experience:
- Using current for home backup power only (to start); could eventually (looking ahead) operate in parallel with the grid
- Testing has been done internally on more complete capabilities and partnering with West Coast utilities to participate in V2X pilots

Organizational Approach to V2X:
- Wants to take crawl, walk, run approach. Start with home backup power (it is simple and tangible like a home generator).
- Need to see the policy side catch up because the programmatic pathways are unclear to determine how much revenue the organization and customer can keep
- Eager to get data in from the first months and years to see how many people are buying the supporting hardware/software. Wants to keep an eye out for how many vehicles are being sold with this capability.

Challenges to V2X Adoption:
- Communication protocols impact the organization's ability to provide a solution using an industry standard. They want it to be interoperable with the rest of the installed chargers. They want to be able to fall back to the ISO standard.
- The ISO 15118-20 communication protocol was released too late to implement as part of the launch, so the organization had to do some themselves
- There is some risk in the OEMs charting their own paths now. OEMs in industry groups are not sharing full sets of information because business decisions about new vehicle lineups are made 2-3 years ahead of time (even longer for EV development because it is an innovative technology that needs R&D).
- Standards may limit the type of computing chip used as well

Potential Solutions to V2X Challenges:
- Hopefully, OEMs are building their software to be back-compatible with ISO15118-20 so the technology and communication split does not continue for too long
- Regarding the chipsets: It is challenging because each company has their own needs and supply chains, and this could make things difficult if all players are limited in their ability to offer a solution
- It is hard to predict what competitors will do. It will depend on the available value streams from doing it alone vs. using a standard.

Other Barriers to Adoption of V2X:
- Companies are still in the process of figuring out where they can capture value. This may depend on the interconnection process throughout the country. Customers and OEMs are navigating this.
- Offboard inverters and transfer switches are more expensive, so that is a barrier because it is trickier than just buying a standard L2 charger for your home
- Interconnection process is different across the US (approvals, permitting). Customers may see navigating this as a barrier. Approval process may also be slow to get interconnection to happen.

Interview #5

Industry: Software
Organizational Focus: Coordinate, control, and aggregate EVs and their data using software platforms and solutions to optimize charging
V2X Experience:

- Organization working internally on proof-of-concept-type projects
- More support within Europe for extending projects beyond just proof of concept
- Projects occurring domestically have been done years prior in Europe
- Most commercialized deployments have been in buses, but some have involved cars as well as solar optimization

V2X Applications and Use Cases:

- V2B is optimizing loads, solar, but not actually exporting energy to the grid (or emergency backup power, but this is a different technology)
- V2G implies you are exporting energy to the grid—could be in response to a price signal or direct request from a system operator, net exporter of energy

Role of Utilities in V2X Adoption:

- Utility partners can drive significant value for aggregators and other EV stakeholders by recognizing the value add of vehicle-to-grid
- Need to produce an appropriate rate to incentivize EVs to discharge energy
- Opportunities to incentivize adoption include offering rebates or funding to lay the necessary wires

Infrastructure Needs for V2X:

- Necessary electrical wiring for V2G was included in the existing funding schemes and facilities, especially for schools
- Customers really look to the approved products list so available funding is often used up on unidirectional chargers
- Challenges arise when customers look to install make-ready infrastructure and/or meter these devices separately

Challenges to V2X Adoption:

- Communications protocols
  - Different standards have different purposes
  - They follow the normal pathway for installing standard inverters: UL1741 and UL1741SA
  - Organization defers to using what utilities and automakers use
  - Signals can be translated into open charge point protocol (OCPP)
  - They also use OpenADR, which is used to simplify and automate demand response and DER integration for utilities and aggregators

Interview #6

Industry: Transportation
Organizational Focus: Provide fleet operations and services for educational school district
V2X Experience:

- Minimal exposure to most of team
- Recently deployed pilot program involving seven buses as first project

Challenges to V2X Adoption:

- Internal challenges with soliciting funding to implement new pilot programs
- Grants are needed to cover the incremental cost of the buses, infrastructure, and transformer upgrades
- Issues with fiber installation at their bus depots and deployment sites
- Operating at scale:
    - Implementing fleet-level solutions involves identifying significant sources of funding for procurement
    - Concern from facilities for infrastructure upgrades and unknowns in consumption

Potential Benefits of V2X:

- Organization sees opportunity to reduce emissions in bus fleet and eliminate exposure of carcinogens to students
- Catalyst for implementing other sustainable practices. Planning to install solar on campus too, along with 1.5 MW bus canopy.

Incentivizing V2X Adoption:

- Local, regional, and federal grands can offer funding to procure buses
- Need specific funding sources for future-proofing infrastructure with V2G
- Operator needs to retain control of vehicles to use them for business purposes
- Value of resiliency:
    - Need to dispatch electricians when an outage occurs—can associate dollar figure with avoided labor
    - Most schools have backup generators, which can only do emergency; buses might be able to handle the load
    - Would like the microgrid option to island instead of just sending electricity back to full grid

Interview #7

Industry: Automotive manufacturer
Organizational Focus: Electric transit bus manufacturing, EVSE manufacturing and installation, and drivetrain manufacturing
V2X Experience:

- Bidirectional charging pilot with other vehicle manufacturers and utility
- Pilot programs are entirely self-funded, no direct utility participation in the funding mechanism
- Organizational involvement: Active in controls on the vehicle side and on the charger side, and it has been essential for them to have controls on both vehicle side and EVSE

V2X Application and Use Cases:

- Electric school buses: Reduce operating costs for school districts
- Transit: Reduce operating costs for school districts
- Resiliency: For transit, may not be great for V2G, because on the road during best times, but for emergency scenarios, can be useful

Technical Challenges to V2X Adoption:

- Communication: How to get the variety of assets to talk together
- Interconnection: Challenges with scaling and integrating into the grid
- Hoping for greater diversity of suppliers that can do V2G; space is nascent, so they do not have options to get other chargers
- Building toward communication protocols, future of communication
    - This has been a problem in basic communication between charger OEMs and vehicle OCPP
    - Nascent standards for V2G is slowing progress
    - 15118-20 will hopefully shore up uncertainty
    - Curious to see impact of Ford F-150 Lightning because of its ability to get customers to be noisy and advocate for more V2G
    - Makes it more challenging for customers if everyone has individual proprietary communication protocols

Incentivizing V2X Adoption:

- Need to develop funding for multiyear programs to understand adoption and participation
- Need consistent financing to scale
- Develop and communicate best practices to answer major technical questions for communication and interconnection
- Need to get past small pilots and one-offs, get more real adoption at scale

Market Barriers to V2X Adoption:

- Which vehicles able to participate and at what time?
- What does participation mean? Works with all chargers?
- Overall customer education (not yet like plugging in a gas car)
- Explaining wholesale participation to customers that never had to think about it is tricky; going to bidirectional will require a lot of education

Appendix 2: Case Studies

Project	Project Start	Application and Use Case	Number of Vehicles	Results	Key Takeaways
BMW ChargeForward	2015	V1G Managed Charging	100	209 demand response events 19.5 MWh	Customer behavior is highly responsive to incentives and prompts
Lion Electric, White Plains, NY	2018	V2G	5	First successful deployment of V2G in New York	V2G has minimal impact on bus availability for transportation
PG&E Epic (2.03b)	2016	V2H	2,486 (survey)	Determined customer sentiment around V2H technology	Customer willingness to pay was lower than estimated V2H system cost
Rialto Electric School Bus Project	2017	V2G	8	Modeled substantial revenue generation potential from grid services, indicating V2G may play a meaningful role in TCO	V2G drives value for distribution grid, and environmental impacts of carbon reduction can be driver for vehicle adoption
Torrance Electric School Bus Project	2017	V2G V2B	6	Demonstrated demand charge management and frequency response	V2G revenue can be substantial; tariffs can help offset initial price
UCSD INVENT	2017	V2G	50+	Demonstrated several applications for vehicle-grid integration	V2G can succesfully be used for targeted demand response
Queens College, NY	2019	V1G V2G	6	Demonstrated demand charge management and emergency backup with solar integration	Utility can initiate strategic partnerships with landmark institutions for mutual benefit in V2X space
Hydro One V2H Backup Power	2021	V2H	10	Pending results seek to assess reliability, duration, and efficiency of EVs, and owner charge/discharge habits	Pending

Appendix 3: Additional Tables

Table 9: Scenarios of V2G Potential in Xcel Energy's Colorado Service Territory

<table>
<tr><th>Year</th><th>EVs</th><th></th><th>% V2G Capable</th><th></th><th>Enrollment Rate</th><th></th><th>Plugged In</th><th></th><th>Participating</th><th></th><th>kW/V2G-Capable EV</th><th></th><th>V2G Capacity (MW)</th></tr>
<tr><td>2023</td><td>55K</td><td rowspan="6">X</td><td>11.6%</td><td rowspan="6">X</td><td rowspan="6">10%</td><td rowspan="6">X</td><td>20%</td><td rowspan="6">X</td><td rowspan="5">50%</td><td rowspan="6">X</td><td rowspan="6">7</td><td rowspan="6">=</td><td>0.45</td></tr>
<tr><td>2030</td><td>600K</td><td>11.6%</td><td>20%</td><td>4.9</td></tr>
<tr><td>2030</td><td>600K</td><td>100%</td><td>20%</td><td>42</td></tr>
<tr><td>2030</td><td>600K</td><td>100%</td><td>60%</td><td>126</td></tr>
<tr><td>2030</td><td>600K</td><td>100%</td><td>100%</td><td>210</td></tr>
<tr><td>2030</td><td>600K</td><td>100%</td><td>100%</td><td>100%</td><td>420</td></tr>
</table>

Table 10: V2X-Enabled EV Deployments in the US

Vehicle	Compatible Model Year Start[63]	V2G/V2B	V2H	V2L Only
Nissan Leaf	2013	✓	✓	✓
Ford F-150 Lightning	2022	-	✓	✓
Genesis GV60	2022	-	-	✓
Hyundai Ioniq 5	2022	-	-	✓
Kia EV6	2022	-	-	✓
Lucid Air	2023	-	✓	✓
Volkswagen ID.4	2023	-	-	✓
Hyundai Ioniq 6	2023	-	-	✓
Genesis Electrified GV70	2023	-	-	✓
Genesis Electrified G80	2023	-	-	✓
Kia Niro EV	2023	-	-	✓
Volkswagen ID. Buzz	2024		✓	✓
Chevrolet Silverado EV	2024	-	✓	✓
Volvo EX90	2024	-	✓	✓
Ram 1500 EV	2024	-	✓	✓
Chevrolet Equinox EV	2024	-	-	✓

Table 11: Bidirectional Charger Deployment in the US

OEM	Market	Inverter Location	Connector	AC/DC	kW	UL	Available
dcbel	Res	Other equipment	CCS/ CHAdeMO	DC	7.6–15.2	Yes	Yes
Ford	Res	Other equipment	CCS	DC	19.2	Yes	Yes
Emporia	Res	Other equipment	CCS	DC	11.5	No	No
Lucid	Res	EV	CCS	AC	19.2	No	No
Wallbox	Res	Charger	CCS	DC	11.5	No	No
Fermata	Comm	Charger	CHAdeMO	DC	15	Yes	Yes
Fermata	Comm	Charger	CHAdeMO	DC	20	No	Yes
Rhombus	Comm	Charger	CCS	DC	60–125	Yes	Yes
Nuvve	Comm	EV	CCS	AC	19.2–52.3	Yes	Yes

Acronyms and Abbreviations

AC .... Alternating Current

ADR .... Automated Demand Response

AI .... Artificial Intelligence

BTM .... Behind the Meter

CCS .... Combined Charging System

CHAdeMO .... Charge de Move

CharIN .... Charging Interface Initiative

DC .... Direct Current

DER .... Distributed Energy Resources

EV .... Electric Vehicle

EVSE .... Electric Vehicle Supply Equipment

FERC .... Federal Energy Regulatory Commission

FMB .... Field Message Bus

GHG .... Greenhouse Gas

GWh .... Gigawatt-Hour (1,000,000 kWh)

INVENT .... Intelligent Electric Vehicle Integration

ISO .... Independent System Operator

kW .... Kilowatt

kWh .... Kilowatt-Hour

L2 .... Level 2

LFP .... Lithium Iron Phosphate

MW .... Megawatt

MWh .... Megawatt-hour (1,000 kWh)

NREL .... National Renewable Energy Laboratory

OCPP .... Open Charge Point Protocol

OEM .... Original Equipment Manufacturer

PG&E .... Pacific Gas and Electric

PRECISE .... Preconfiguring and Controlling Inverter Setpoints

R&D	Research and Development
ROI	Return on Investment
RTO	Regional Transmission Organization
TCO	Total Cost of Ownership
UCSD	University of California, San Diego
UK	United Kingdom
US	United States
V	Volt
V1G	Vehicle-to-Grid Communications for Charge Management
V2B	Vehicle-to-Building
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
V2L	Vehicle-to-Load
V2X	Vehicle-to-Everything

Glossary of Key Terms

Digital energy management platforms: Software-based tools leveraging communication technologies to manage electricity flow between electricity-consuming devices and the grid.

Interconnection: The process by which a connection to the grid is authorized to back-feed into local grid infrastructure systems.

Degradation: Associated with the charge/discharge cycling of batteries. V2X use cases likely increase cycling and therefore likely increase degradation.

Depreciation: The devaluation of assets as a function of use, closely tied to degradation.

Three-phase: An electrical infrastructure architecture common for grid distribution systems and within some commercial and industrial buildings. It is rare in residential buildings, where the single-phase architecture is more common.

Nickel-rich battery chemistries: A collection of battery chemistry technologies that use varying quantities of nickel in battery cathodes such as nickel manganese cobalt or nickel cobalt aluminum.

Technology ecosystems: A collection of distinct technologies that can be used together to produce a solution. Described as closed or open: closed indicates limited interoperability with technologies from multiple suppliers; open indicates multiple suppliers providing multiple interoperable technologies.

Endnotes

[1] Vermont Energy Investment Corporation and RAP, *In the Driver's Seat: How Utilities and Consumers Can Benefit from the Shift to Electric Vehicles* (2015), pg. 11.
[2] Per Atlas Public Policy's EValuateCO dashboard, February 7, 2023.
[3] Per the EValuateCO dashboard, February 7, 2023; includes 7,644 Nissan Leafs, 646 Mitsubishi Outlanders, and 357 Ford F-150 Lightnings.
[4] Ford, Ford Intelligent Back-up Power (2022).
[5] Assumes a 240-mile range and efficiency of 3.54 miles/kWh, based on U.S. Department of Energy (DOE), Alternative Fuels Data Center, Average Range and Efficiency of U.S. Electric Vehicles (2021).

[6] American Association of State Highway and Transportation Officials, *Commuting in America 2021*, Appendix A, p. 28.

[7] Xcel Energy, *Driving Toward a Carbon-Free Future: Electric Transportation Vision* (2022).

[8] Emre Gençer et al., "Can Vehicle-to-Grid Facilitate the Transition to Low-Carbon Energy Systems?" *Energy Advances* 1 (2022): 984-98.

[9] See Appendix 3, Table 10.
[10] See Appendix 3, Table 10.
[11] Jason Porzio and Corinne D. Scown, "Life-Cycle Assessment Considerations for Batteries and Battery Materials," *Advanced Energy Materials* 11, no. 33 (2021), Table 1, p. 2.

[12] DOE, Alternative Fuels Data Center, Electric Vehicle Benefits and Considerations.

[13] Installation costs are derived from the Sunrun website when Home Integration System purchase and installation are bundled with Ford Charge Station Pro installation—applicable in 22 states where Sunrun provides installation service.

[14] Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, RMI (2019).

[15] The Charge Station Pro is included with the extended-range version of the F-150 Lightning but can be purchased separately for the standard-range model at $1,310.

[16] Sunrun Home Integration System hardware price.

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[19] See Appendix 2: Case Studies, PG&E Epic (2.03b).

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[21] A single Tesla 13.5 kWh battery costs $12,850, based on Alexis Carthan, "How Much Does the Tesla Powerwall Cost? (2023 Guide)", *This Old House*, February 23, 2023. A 9 kWh Generac battery costs $18,000, based on Lee Wallender, How Much Does a Generac PWRCell Battery Cost and Is It Worth It?, *Forbes*, October 18, 2022.

[22] Colorado CarShare, "Colorado CarShare Ups Our Climate Efforts."

[23] City of Boulder, Colorado, "Innovative Electric Vehicle Charger Shows Financial Promise in First Year," March 29, 2022.

[24] Business Wire, "Electric Vehicle Generates Revenue and Energy Savings Paving the Way for Mainstream Adoption of Vehicle-to-Everything (V2X) Technology," January 27, 2022.

[25] This trial also generated $4,200 in V2G revenue from National Grid's ConnectedSolutions demand response program, which annualizes to $350 per month.

[26] Jonathan Susser and Daniel Real, "Roanoke Electric Cooperative, Fermata Energy Show Promise of Vehicle-to-Everything Technology," Advanced Energy, October 5, 2021.

[27] Based on Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, RMI (2019). Additional operational costs (e.g., networking and data contracts, maintenance) will vary based on site requirements and types of technologies used. For commercial L2 chargers, networking and data contracts have been surveyed at no more than $250/year, while DOE guidance indicates station owners should budget maintenance costs at $400/year per charger. These costs are likely higher for V2B systems, but it is not clear by how much.

[28] See Appendix 1: Interview Notes, Interview #1.

[29] See Appendix 1: Interview Notes, Interview #1.

[30] "For budgeting purposes, some industry stakeholders assume EVSE has at least a 10 year lifespan," per DOE, *Costs Associated with Non-Residential Electric Vehicle Supply Equipment* (2015), p. 21.

[31] Includes 286 participants in Kaluza's V2G trial, summarized in *What's Next for Vehicle-to-Everything?* (2022), https://info.kaluza.com/whats-next-for-vehicle-to-everythingand 135 participants in Powerloop's V2G trial, summarized in Energy Saving Trust, *Powerloop Vehicle-to-Grid Trial: Customer Insights and Best Practice Guide* (2022).

[32] See Appendix 2: Case Studies, Torrance County Electric School Bus.

[33] Dominion Energy, "Electric School Buses."

[34] Taylor Ekbatani, "V2G Findings Announced from New York State Electric School Bus Project," *School Transportation News*, April 26, 2022.

[35] Nuuve, "Blue Bird Delivers North America's First-Ever Commercial Application of Vehicle-to-Grid Technology in Electric School Bus Partnership with Nuvve and Illinois School Districts," March 23, 2021.

[36] DTE Energy, "DTE Energy Partners with Manufacturers and Dealership to Deploy Electric Buses to Schools," February 2, 2021.

[37] Thomas Built Buses, "Beverly Massachusetts Electric School Buses Make V2G Energy Transfer History," November 19, 2021.

[38] Ryan Gray, "First West Coast School Bus V2G Pilot Project to Begin," *School Transportation News*, July 28, 2022.

[39] Christian Burney, "Durango's Electric School Bus Is Like a Huge Battery on Wheels," *Durango Herald*, January 5, 2022.

[40] Nuuve, "San Diego County's Ramona Unified School District, Blue Bird and Nuvve Unveil 8 New V2G-Enabled and Qualified Electric School Buses," October 11, 2022.

[41] Vermont Community Newspaper Group, "Four New Electric Buses Come Online in South Burlington," *The Other Paper*, September 1, 2022.

[42] "Drivers and student riders indicated they were pleased with vehicle performance and bus availability," per Taylor Ekbatani, "V2G Findings Announced from New York State Electric School Bus Project," *School Transportation News*, April 26, 2022.

[43] See Appendix 2: Case Studies, Torrance County Electric School Bus.

[44] Xcel Energy, "Colorado Interruptible Service Option Credit (ISOC)" (2021), ISOC Credits per kW Monthly Credit, 40 hours, unconstrained, 10-minute notice.

[45] DOE, *Costs Associated with Non-Residential Electric Vehicle Supply Equipment* (2015).

[46] "Wang *et al.* shows degradation to be minimal when vehicles are selectively utilized for peak shaving and regulation service on 'high demand' days, rather than used around the clock," per Emre Gençer et al., "Can Vehicle-to-Grid Facilitate the Transition to Low-Carbon Energy Systems?" *Energy Advances* 1 (2022): 984-98, p. 987.

[47] Jason Porzio and Corinne D. Scown, "Life-Cycle Assessment Considerations for Batteries and Battery Materials," *Advanced Energy Materials* 11, no. 33 (2021), Table 1, p. 2.

[48] See Appendix 3, Table 10.

[49] Nissan, "Nissan Approves First Bi-directional Charger for Use with Nissan LEAF in the U.S.," September 7, 2022.

[50] See VEIC, "Electric School Buses Available for Purchase," https://www.veic.org/Media/Default/documents/resources/reports/types-of-electric-school-buses.pdfand BYD, "BYD Introduces Innovative and Safe Type A Battery Electric School Bus with V2G Technology," January 26, 2022.

[51] See CharIN, Position Papers and Regulation.

[52] See Appendix 3, Table 11.

[53] Tesla, "Opening the North American Charging Standard," November 11, 2022.

[54] Everoze, EVConsult, UK Power Networks, and Innovate UK. *V2G Global Roadtrip: Around the World in 50 Projects* (2018), p. 28.

[55] Kaluza, *What's Next for Vehicle-to-Everything?* (2022), p. 19.

[56] Robert Walton, "SMUD Tests Tool to Accelerate Rooftop Solar Interconnections, Utility Dive," November 10, 2022.

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[63] Nissan announced bidirectional charging for the Leaf in 2022, with backward compatibility to model year 2013. Other OEMs, like Volkswagen, have indicated they may also make prior model year EVs bidirectional capable with over-the-air updates.

About Xcel Energy

At Xcel Energy, we're not waiting for the future. We're busy building it. Every day, we power millions of homes, businesses, and communities across parts of eight Western and Midwestern states. Our customers rely on us to be there 24/7 with safe, affordable electricity and natural gas. We've taken a leadership role as the first major power company in the US to announce a vision to reduce carbon emissions 80% by 2030 and provide our customers 100% carbon-free electricity by 2050. We see significant EV growth on the horizon, which will expand our clean energy leadership to the transportation sector, drive electricity sales growth, and help keep bills low for customers. We have set an aggressive goal to power 1.8 million EVs across our eight-state service territory—or approximately 1 out of 5 cars on the road—by 2030.

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Residential EV Subscription Service Pilot: Findings by Learning Objective

Pilot Learning Objective	Findings
Assess customer understanding and satisfaction of a flat rate for EV charging	o In early 2020, four months after launch, we saw overwhelming interest in the program, with 60 applications (more than 30% coming from auto dealerships). o We observed infrequent customer feedback that their participation in the pilot may impact them financially. Those who are hesitant to participate due to the flat fee design of the pilot typically withdraw their enrollment altogether, switch to the EV Accelerate At Home program, or switch to another off-peak Time-Of-Use rate that the Company offers to lessen the potential financial impact of a flat rate for EV charging. o From our post-charger installation surveys, we've received 73 responses from the 150 customers that have had a charger installed for a response rate of 49%. o Overall satisfaction of the Installation Experience continues to be high as compared to EV Accelerate At Home, with a satisfaction score of 96% o Satisfaction with the upfront experience such as the Ease of Enrollment, and Information about Program Costs and How the Program Works, all scored in the 96% or higher range, which are higher satisfaction scores than what was received for the EV Accelerate At Home program (79%). ▪ This difference indicates that a flat monthly subscription rate for EV charging is easily understood by customers. o 92% satisfaction with Communication from Xcel Energy o 90% were highly likely to recommend the program to a friend o 81% very/extremely satisfied with their charging schedule or time window, o 82% very/extremely satisfied with the value for the energy used, and o 78% very/extremely satisfied with program services (charger, installation, maintenance)

Pilot Learning Objective	Findings
	○ 88% of pilot participant research respondents very clearly understood "unlimited off-peak charging" ○ 72% stated that they understood it completely
Assess if the pilot and rate structure provide appropriate signals and automation for off-peak charging	○ May 2022 research showed that 88% of pilot participant research respondents very clearly understood "unlimited off-peak charging", with 72% stating that they understood it completely. ○ In the 2021-2022 reporting period, 96% of all charging during the pilot occurred during the off-peak window.
Assess the costs for providing service to customers and determine the accuracy of flat rate cost assumptions.	○ In the early stages of the Residential EV Subscription Pilot in 2020-2021, costs exceeded revenues. We anticipated immediate growth in the pilot and expected that, over the life of the pilot, subscription revenues would come close to matching program costs. Due to the COVID-19 pandemic, pilot enrollment initially slowed, but returned to a brisk pace. ○ By 2023, total revenues have exceeded total costs in the pilot. Continued costs are relatively minimal as the program has reached the participation cap and does not require a large amount of ongoing costs beyond O&M costs. ○ The pilot was designed to recover the full costs from participations over the duration of equipment life and we anticipate that the program is on track to do so if cost and revenue trends continue. ○ While only a few customers were found to charge around 2,000 kWh per month or more, 68% of participating customers charge less than 500 kWh per month, and 96% charge less than 1,000 kWh per month. ○ The average monthly consumption among all participants was 403 kWh. Among those who charged less than 1,000 kWh per month, the average monthly consumption was 372 kWh. As such, participants have been slightly underpaying for the subscription since the current rate structure assumes 339 kWh off-peak per month. ○ We suspect that the customers who are charging at around 2,000 kWh per month or more are charging two vehicles on the pilot, which breaches the customer

Pilot Learning Objective	Findings
	service agreement and requirement of one vehicle per customer charge and subscription.

Residential EV Subscription Service Pilot: Final Reporting Requirements

Reporting Requirements	Findings
Participant Information A) Number of pilot participants B) Number selecting each type of equipment C) Number choosing to pre-pay for the charger, and number choosing to spread the payments over time D) Number choosing Windsource, and number choosing standard rates	A) Currently we have 127 participants enrolled B) 104 have chosen the ChargePoint model and 23 have chosen Enel X C) To date, 108 have chosen the bundled option, which allows them to pay for the charger monthly, and 19 chose to prepay for the charger at the time of installation D) 77 have chosen to use Windsource. (2023 Annual Report, pg 19)
kWh consumption details on a per month basis, including: A) kWh consumed in the on-peak period kWh consumed in the off-peak period B) Comparison of actual consumption to estimated amounts C) Highest and lowest usage customer in each month	A) See 2023 Annual Report, Attachment A. B) See 2023 Annual Report, Attachment A. When developing the EV Subscription Service pilot, we estimated that the average customer would have a monthly energy usage of 340 kWh. The average monthly charging usage per customer during the pilot has been about 410 kWh per month (2023 Annual Report, page 20) C) See 2023 Annual Report, Attachment A.
The costs and revenues associated with each service option, including the amount of metering equipment added to rate base and whether the pilot is revenue neutral	o See 2023 Annual Report, pages 20-21.
Insights drawn from customer experience and pilot performance under Xcel's safety and reliability standards	o Based on customer satisfaction and managed charging participation with a flat subscription rate, the pilot has been successful and has met our safety and reliability standards. (**2022** Annual Report, pages 24-25)

Reporting Requirements	Findings
Any problems encountered connecting to the homeowner's wireless internet connection	o See **2022** Annual Report, pages 14-15.
A side-by-side comparison of data on Xcel's current Electric Vehicle Service Pilot Program and Xcel's new Electric Vehicle Subscription Pilot Program, and a discussion about whether any difference in results may have resulted from differences between the two pilots' terms and conditions	o Overall satisfaction of the Installation Experience for the Residential EV Subscription Service Pilot continues to be high as compared to EV Accelerate At Home, with a satisfaction score of 96%. o Satisfaction with the upfront experience such as the Ease of Enrollment, and Information about Program Costs and How the Program Works, all scored in the 96% or higher range, which are higher satisfaction scores than what was received for the EV Accelerate At Home program (79%). o This difference indicates that a flat monthly subscription rate for EV charging is easily understood by customers. o Further, managed charging participation is also higher in the Subscription pilot, with 96% of all charging occurring off-peak compared to more than 80% with EV Accelerate At Home. However, this may be a result of the EV Accelerate At Home program switching to a three-period TOU rate while the subscription pilot maintained a two-period TOU schedule. (**2022** Annual Report, pages 24-25)

	Standard					Renewable				
	Rate	**KWh**	**Bundled**	**BYOC**	**Pre-Pay (Closed)**	**Rate**	**KWh**	**Bundled**	**BYOC**	**Pre-Pay (Closed)**
Customer Charge			$16.63	$6.73	$5.95			$16.63	$6.73	$5.95
Energy Charges										
Off-Peak	$0.038250	375	$14.34	$14.34	$14.34	$0.038250	375	$14.34	$14.34	$14.34
Fuel Clause Rider	$0.038567	375	$14.46	$14.46	$14.46	$0.041580	375	$15.59	$15.59	$15.59
Other Riders Charges										
Transmission Cost Recovery	$0.004591	375	$1.72	$1.72	$1.72	$0.004591	375	$1.72	$1.72	$1.72
Renewable Development Fund	$0.001385	375	$0.52	$0.52	$0.52	$0.001385	375	$0.52	$0.52	$0.52
Conservation Improvement Program	$0.002225	375	$0.83	$0.83	$0.83	$0.002225	375	$0.83	$0.83	$0.83
State Energy Policy Rider	$0.000000	375	$0.00	$0.00	$0.00	$0.000000	375	$0.00	$0.00	$0.00
Renewable Energy Standard	0.981%		$0.30	$0.21	$0.20	0.981%		$0.30	$0.21	$0.20
Sub-Total Other Rider Charges			$3.37	$3.28	$3.27			$3.37	$3.28	$3.27
Total Monthly Charge			**$48.80**	**$38.81**	**$38.02**			**$49.93**	**$39.94**	**$39.15**

In dollars, except where specified

Redline

AVAILABILITY

Available ~~while this Pilot Service is in effect~~ to Residential Service customers for service only to electric vehicle loads including battery charging and accessory usage. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service with this tariff. ~~Customers electing~~ Pre-Pay Option service is closed and not available to new customers ~~are separately invoiced at the time of installation~~. BYOC Option service is available to customers electing to bring their own charging equipment as approved by the Company, prior to beginning service with this tariff. The customer must possess~~complete Company-approved documentation verifying possession~~, through ownership or lease, ~~of~~ an electric vehicle, meaning any device or contrivance that transports persons or property and that is able to be powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electricity. Electric vehicle includes, but is not limited to, an electric vehicle as defined in Minnesota Statues ~~as defined in~~ Section 169.011, subdivision 26a; an electric-assisted bicycle as defined in Section 169.011, subdivision 27; an off-road vehicle, as defined in Section 84.797, subdivision 7; a motorboat, as defined in Section 86B.005, subdivision 9; or an aircraft, as defined in Section 360.013, subdivision 37. ~~of Minnesota law.~~ ~~N~~C

CONTRACT

Customers must contract for this service through an ~~Electric Vehicle Subscription Pilot Electric~~EV Accelerate At Home Customer Service Agreement with the Company. The ~~initial~~ contract period will be as long as the customer wishes to use the equipment~~normally be for 24 months~~. Customers who initially contracted for the Residential Electric Vehicle Subscription Pilot Service through an Electric Vehicle Subscription Pilot Electric Service Agreement can still take service under that agreement through the 36-month term. At the end of that agreement, the customer can continue service by contracting for the service through an EV Accelerate At Home Customer Service Agreement or terminate their service at no cost to them. Contract allows customers to participate with ~~only~~ more than one electric vehicle. C

CHARACTER OF SERVICE

Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION

Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable*Connect Pilot Program ~~and High-Efficiency Energy Purchase~~ (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable. ~~N~~ T

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer's Expected Average Electric Vehicle kWh Usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and /or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

(Continued on Sheet No. 5-8.2)

RATE

Customer Charge per Month (Up to 1,000 kWh of off-peak charging per month) N

General System Energy		
Bundled (A82)	$~~42.50~~48.80	R
Pre-Pay Option (A83) (Closed)	$~~32.65~~38.02	CR
BYOC (A84)	$38.81	N
Renewable Energy (Windsource)		
Bundled (A82)	$~~45.02~~49.93	R
Pre-Pay Option (A83) (Closed)	$~~35.17~~39.15	CR
BYOC (A84)	$39.94	N

Excess On-Peak Period Energy Charge per kWh

June - September	$0.20497
Other Months	$0.16508

Excess Off-Peak Energy Charge per kWh (above 1,000 kWh per month) N

All Months	$0.04170	N

PRE-PAY OPTION (CLOSED) C

The Pre-Pay Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company.

BYOC OPTION N

Customers choosing the BYOC Service are required to utilize a vehicle charger model that is approved by the Company for use for this rate. Customers choosing the BYOC Service are required to have a Company-contracted electrician perform a site visit to install and hardwire the charging equipment, if needed, or to confirm equipment eligibility and equipment set up to ensure program compatibility. The cost of the site visit is included in the monthly customer charge. Customers choosing the BYOC Service are required to utilize a vehicle charger model that is approved by the Company for use for this rate. N

INTERIM RATE ADJUSTMENT ~~N~~

An 8.92% Interim Rate Surcharge will be applied to rate components specified in the "Interim Rate Surcharge Rider" to service provided beginning January 1, 2022. ~~N~~ ~~N~~

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE

The monthly customer charge includes preset fuel charges for established energy usage during off-peak and on-peak periods. Excess on-peak period energy charges are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT

The monthly customer charge includes a preset Resource Adjustment charge for established energy usage during off-peak and on-peak periods. Excess on-peak period energy charges are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-8.3)

~~**MONTHLY MINIMUM CHARGE**~~ L
~~Customer Charge.~~

~~**SURCHARGE**~~
~~In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.~~

~~**LATE PAYMENT CHARGE**~~
~~Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.~~ L

(Continued on Sheet No. 5-8.3)

MONTHLY MINIMUM CHARGE L
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5. L

DEFINITION OF PEAK PERIODS ~~N~~
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF EXPECTED AVERAGE ELECTRIC VEHICLE KWH USAGE
The expected average electric vehicle kWh usage is defined as the Company's estimated average monthly EV energy consumption across all pilot participants.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles. ~~as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.~~ ~~D~~ ~~D~~

TERMS AND CONDITIONS OF SERVICE

1. Residential ~~Electric Vehicle~~EV Accelerate At Home Subscription ~~Pilot~~ Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage. ~~T~~
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access ~~for Company-owned~~to charging equipment for the recording and wireless communication of energy usage. ~~C~~
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates. ~~N~~
6. Customer must execute an EV Accelerate At Home Customer ~~Electric Vehicle Subscription Pilot~~ Service Agreement with the Company. T

EV Home Service Offerings

Rate Options	Customer upfront out-of-pocket expenses	Customer monthly charge for EV Home Service	Services included in monthly charge for EV Service	Monthly usage billed
Bundled Residential EV Accelerate At Home Pay As You Go Subscription Service Rate Code: A82	• Premises wiring	$48.80	•Charging Equipment and installation •Customer services •Customer accounting •Load monitoring and data management •Maintenance service •Charging Equipment removal and relocation	EV Charging is billed according to Rate Code A82
BYOC Residential EV Accelerate At Home Pay As You Go Service Rate Code: A84	• Premises wiring	$38.81	•Charging equipment installation (initial electrician visit) •Customer services •Customer accounting •Load monitoring and data management	EV Charging is billed according to Rate Code A84

(Continued on Sheet No. 7-114)

XCEL EV Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement (Continued)

In order to enroll in the Program, please review these terms and indicate your understanding and agreement below by selecting the appropriate check box on the Program enrollment page at [link to be generated at xcelenergy.com]. ~~Xcel Energy will notify the Customer (a) that the Customer's eligible Charging Equipment has been installed, and (b) Xcel Energy and the equipment vendor have confirmed that the Charger is operational and activated, by e-mail (the date of the e-mail will be the "Activation Date").~~ Once enrolled, Xcel Energy will arrange to have a qualified technician install the Charging Equipment at your Site or, if a BYOC participant, perform the initial electrician visit to ensure the equipment meets the program equipment requirements. When installation or visit is complete, Xcel Energy will notify you that the Charger is operational and activated, by e-mail (the date of the e-mail will be the "Activation Date"). C C

Definitions
"Electric Vehicle," defined in Section 169.011, subdivision 26a of Minnesota law, means a motor vehicle that is able to be powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electric current, and meets or exceeds applicable regulations in the Code of Federal Regulations, title 49, part 571. Electric vehicles include neighborhood electric vehicles, medium-speed electric vehicles, and plug-in hybrid electric vehicles.

"Charging Equipment, or Charger, or Equipment" means the installed device used to deliver electricity from the Premises Wiring to the electric vehicle, meeting Standard J1772 of the Society of Automotive Engineers International and listed under applicable UL Standards and requirements or equivalent listing by a nationally recognized testing laboratory. This device includes the ungrounded, grounded, and Equipment grounding conductors, the Electric Vehicle connectors, attachment plugs, and all other fittings, devices, power outlets or apparatuses associated with the installed device, but does not include Premises Wiring.

"Premises Wiring" means a dedicated 208/240V AC circuit that supplies electricity directly to the installed Charging Equipment. This includes the protective breaker at the supply panel, wiring, final junction box, receptacle and all attachments and connections. The Customer retains ownership and is wholly responsible for the Premises Wiring, including that it meets all workmanship standards and applicable requirements in the National Electric Code, Minnesota law and Administrative Rules, and local municipal codes. ~~T~~ ~~T~~ ~~T~~

"Site" means the enclosed garage or other area approved by Xcel Energy on property owned or rented by the Customer as the Customer's dwelling.

(Continued on Sheet No. 7-115)

1. Eligibility and Availability

To be eligible for the EV ~~Home Service~~Accelerate At Home Program (Rate Codes A79, A80), Customers must: T

- have an active Xcel Energy electric service account in Minnesota with no past due bills, disconnection notices, or pay arrangements; C ~~T~~ C ~~T~~
- rent or own their dwelling, provided that Customers who are renting their dwelling have a separately metered service, are willing to pay for any necessary make-ready infrastructure, and have the building owner's written consent to participate in the EV Home Service;
- represent that the Site is owned by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with a Xcel Energy residential electrical account on which the Charger will be installed;
- complete Xcel Energy-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on its behalf, for the exclusive use of tracking the energy used to charge their electric vehicle;
- have wireless internet ("Wi-Fi") service at Site;
- not be on current Residential EV Service Rate (~~RATE CODE~~Rate Code A08). If participant is already enrolled, they must unenroll for the duration of their participation on the EV Home Service Program; T
- not participate in the Time of Use Rate Design Pilot Program. If the Customer is already enrolled, they must unenroll for the duration of their participation in the EV Home Service; and
- not participate in the Company's Net Metering tariffs.

To be eligible for the ~~Voluntary Electric Vehicle Charger Service~~EV Accelerate At Home Program Voluntary Electric Service (Rate Code A76), Customers must: T T

- have an active Xcel Energy electric service account in Minnesota with no past due bills, disconnection notices, or pay arrangements; ~~T~~ ~~T~~
- rent or own their dwelling, provided that Customers who are renting their dwelling have a separately metered service, are willing to pay for any necessary make-ready infrastructure, and have the building owner's written consent to participate in the Voluntary Electric Vehicle Charger Service;
- represent that the Site is owned by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with an Xcel Energy residential electrical account on which the Charger will be installed;
- complete Xcel Energy-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on its behalf, for the exclusive use of tracking the energy used to charge their electric vehicle; and
- have Wi-Fi service at Site;
- be on a current Residential Time of Day rate (~~RATE CODE~~Rate Codes A02 and A04). T

(Continued on Sheet No. 7-115.1)

To be eligible for the EV Accelerate At Home Subscription Program (Rate Codes A82, A84), Customers must: N

- Agree to the terms and conditions of this Services Agreement;
- Have an active Xcel Energy residential electric service account in Xcel Energy's Minnesota regulated electric service territory with no past due bills, disconnection notices, or pay arrangements;
- rent or own the Site, provided that if you rent the Site, you must have a separately metered service, pay for any necessary Premises Wiring, and have the Site owner's written consent to participate in the EV Accelerate At Home Program;
- represent that the Site is owned or rented by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with a Xcel Energy residential electrical account on which the Charger will be installed;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on Xcel Energy's behalf, or be inspected and confirmed as eligible by an Xcel Energy contracted electrician, for the exclusive use of tracking the electricity used to charge your Electric Vehicle;
- have wireless internet ("Wi-Fi") service at Site;
- not be on current Xcel Energy Residential EV Service Rate (Rate Code A08). If you are already enrolled on Rate Code A08, you must unenroll for the duration of your participation in the EV Accelerate At Home Program;
- not participate in the Residential Time of Day Service Rate (Rate Codes A02, A04); if Participant is already enrolled, they must unenroll for the duration of their participation in the EVAAH Subscription Program;
- not participate in the EVAAH Pay-As-You-Go (Rate Codes A80, A81);
- not participate in the Time of Use Rate Design Pilot Program; if Participant is already enrolled, they must unenroll for the duration of their participation in the EVAAH Subscription Program; and
- not participate in the Company's Net Metering tariffs. N

(Continued on Sheet No. 7-116)

3. Customer's CHARGING EQUIPMENT Obligations and Duties

Throughout the Term of this Agreement:

- 3.1 Customer shall grant to Xcel Energy such access to the Site and sufficient space for locating the Charging Equipment at the Site as may be deemed necessary or desirable by Xcel Energy for the Work. Installations must conform to the Company's specifications.

- 3.2 Customer shall be responsible for the expense and installation of any Premises Wiring necessary to provide electricity to the Charging Equipment. Customer may, in Customer's sole discretion, opt to use Xcel Energy's third-party independent contractor to install the necessary Premises Wiring in addition to the Charging Equipment, provided that Customer will be responsible for the expense to have the third-party independent contractor install the Premises Wiring.

- 3.3 Until the Charging Equipment (in Xcel Energy's sole discretion) is deemed non-functional or this Agreement is terminated, the Customer hereby consents to and shall permit both Xcel Energy and any underlying equipment manufacturer, vendor or subcontractor to the underlying manufacturer or vendor to access, collect and share with their respective parent, affiliates, subsidiaries and subcontractors all data from the Charger with respect to vehicle charging activity, vehicle usage and technical performance (the "Data") of the vehicle and Charger. Xcel Energy shall comply with all federal, state, and local laws, as applicable, in the access, collection, and sharing of the Data. In the event the Charger fails to operate or otherwise require repair, the Customer shall promptly notify Xcel Energy.

- 3.4 If you are enrolled in Bundled EVAAH Pay As You Go or Bundled EVAAH Subscription Pay As You Go and are experiencing issues with the Charger at the Site, in addition to contacting Xcel Energy, you must contact the Charging Equipment manufacturer to diagnose Charger performance issues. The contact information for the Charging Equipment manufacturer may be found on Xcel Energy's website. You may also contact Xcel Energy as provided below for the Charging Equipment manufacturer's contact information. Xcel Energy will not be able to correct problems with a Charger until Xcel Energy has received the Charging Equipment manufacturer's diagnosis of the problem. If the Charging Equipment manufacturer is unable to remedy the issue with the Charger during remote diagnostics, Xcel Energy will work with the Charging Equipment manufacturer to determine the necessary remedial actions, which may include replacing the defective Charger or sending an Xcel Energy electrician to the Site for further diagnosis. If the Charger manufacturer determines the Charger is damaged due to misuse or neglect, Xcel Energy will be notified and you will be responsible for purchasing the Charger at the Charging Equipment Buyout Amount. Xcel Energy will provide you an invoice in the amount of the Charging Equipment Buyout Amount and you agree to pay such amount within thirty days of your receipt of such invoice. Upon Xcel Energy's receipt of your payment of the Charging Equipment Buyout Amount, this Service Agreement and your participation in EV Accelerate At Home Program will automatically terminate and Xcel Energy will transfer title to the Charging Equipment on an "As-Is" basis, with no warranty of any kind, express or implied. Upon such termination, you will be responsible for any necessary maintenance, repair, or replacement of the Equipment. N

- 3.5 If your Charger has been subject to fire, flood, or other natural disaster, the Charging Equipment manufacturer and Xcel Energy will need to verify that the Charger is functional and safe for continued use in the EV Accelerate At Home Program. In the event of such fire, flood or other natural disaster, you must contact the Charging Equipment manufacturer and Xcel Energy. The Charging Equipment manufacturer will help determine if your Charger is communicating properly following the fire, flood or natural disaster. If enrolled in Bundled EVAAH Pay As You Go or Bundled EVAAH Subscription Pay As You Go and the Charging Equipment manufacturer N

(Continued on Sheet No. 7-117.1)

- ~~3.4 Customer, Xcel Energy and its authorized equipment manufacturers, vendors, and subcontractors shall comply with all applicable rules and regulations of federal, state or city regulatory agencies relating to the Work and operation of the Charger, including environmental requirements associated therewith.~~ L

- ~~3.5 Customer shall maintain the area surrounding the Charging Equipment and will promptly notify Xcel Energy of any problems related to the Equipment that the Customer becomes aware of. Such maintenance includes, but is not limited to, pavement maintenance, pruning of vegetation, and snow removal. For avoidance of doubt, Customer is not responsible for the ongoing maintenance of the Equipment, itself.~~

- ~~3.6 Customer agrees to remedy minor issues that do not require qualified technicians to address, such as resetting infrequently tripped circuit breakers.~~

- ~~3.7 Customer agrees to provide access and assistance to facilitate random Charging Equipment testing, if selected. Such cooperation may include, but not be limited to, periodic inspection of the Charger and the addition of monitoring hardware or software at Xcel Energy's expense.~~

- ~~3.8 Customer agrees to participate in surveys and provide feedback about the Program as well as cooperate with Xcel Energy in fulfilling Xcel Energy's reporting requirements to any federal, state or local regulatory or governing entities.~~ L

(Continued on Sheet No. 7-117.1)

determines the Charger is still functioning and communicating properly, before continued use of the Charger under the EV Accelerate At Home Program, an Xcel Energy electrician will need to inspect the connectors, pins, and cable for damage to verify that the Charger is safe and functioning properly. If the Xcel Energy electrician determines that the Charger is safe and functioning, the Charger may continue to be enrolled in the EV Accelerate At Home Program. However, in the event the Charger is deemed by Xcel Energy to be unsafe and/or nonfunctional due to a flood, fire or other natural disaster, you will be responsible for purchasing the Charger at the Charging Equipment Buyout Amount. Xcel Energy will provide you an invoice in the amount of the Charging Equipment Buyout Amount and you agree to pay such amount within thirty days of your receipt of such invoice. Upon Xcel Energy's receipt of your payment of the Charging Equipment Buyout Amount, this Service Agreement and your participation in EV Accelerate At Home Program will automatically terminate and Xcel Energy will transfer title to the Charging Equipment on an "As-Is" basis, with no warranty of any kind, express or implied. Please contact Xcel Energy for copies of statements reflecting the Charging Equipment Buyout Amount for your insurance provider, if needed. N

- 3.5 Customer, Xcel Energy and its authorized equipment manufacturers, vendors, and subcontractors shall comply with all applicable rules and regulations of federal, state or city regulatory agencies relating to the Work and operation of the Charger, including environmental requirements associated therewith. LT

- 3.6 Customer shall maintain the area surrounding the Charging Equipment and will promptly notify Xcel Energy of any problems related to the Equipment that the Customer becomes aware of. Such maintenance includes, but is not limited to, pavement maintenance, pruning of vegetation, and snow removal. For avoidance of doubt, Customer is not responsible for the ongoing maintenance of the Equipment, itself. T

- 3.7 Customer agrees to remedy minor issues that do not require qualified technicians to address, such as resetting infrequently tripped circuit breakers. T

- 3.8 Customer agrees to provide access and assistance to facilitate random Charging Equipment testing, if selected. Such cooperation may include, but not be limited to, periodic inspection of the Charger and the addition of monitoring hardware or software at Xcel Energy's expense. T

- 3.9 Customer agrees to participate in surveys and provide feedback about the Program as well as cooperate with Xcel Energy in fulfilling Xcel Energy's reporting requirements to any federal, state or local regulatory or governing entities. T L

(Continued on Sheet No. 7-118)

- 4.8 Xcel Energy, in its sole discretion, may terminate the Agreement at any time, in which case Xcel Energy will provide Customers paying the bundled service customer charge with sixty (60) days' prior written notice of its intent to terminate the Agreement and remove the Charging Equipment. For Customers paying the prepay service customer charge, Xcel Energy will provide the Customers with sixty (60) days' prior written notice of its intent to terminate the Agreement and transfer ownership of the Charging Equipment to the Customer at no cost. For Customers using the Installation-Only Service, Xcel Energy will provide the Customers with sixty (60) days' prior written notice of its intent to terminate the Agreement. The Customers may continue using the Charging Equipment after termination, before it is transferred or removed, as applicable.

5. Title to Equipment and Data

- At all times under this Agreement where Xcel Energy shall own and maintain title to the Charging Equipment, the Customer shall not make any alterations, changes or modifications to the Charger without first securing prior written permission from Xcel Energy and/or any applicable underlying manufacturer. All rights, title and interest in the Equipment Data and related information collected from the Equipment shall also immediately vest in Xcel Energy.

  Xcel Energy shall therefore have the right to use, copy, and distribute such Data and information as necessary and helpful to evaluate electric vehicles and electric vehicle support equipment and for any other Xcel Energy business purpose. To the extent applicable, Xcel Energy shall indemnify and hold harmless the Customer from any and all claims whatsoever for the use and distribution of said Data.

6. Insurance Coverage

- Customer shall have in full force and effect a standard fire and homeowner's insurance policy with amounts sufficient to cover the full replacement cost of the Site. The Parties hereby waive any and all claims and rights of action (by way of subrogation or otherwise) against the other (and against any insurance company insuring the other Party) which may hereafter arise on account of bodily injury or damage to the Charging Equipment or to the Site, resulting from any fire, or other perils or claims of the kind covered by standard fire and homeowner's insurance policies with extended coverage (Causes of Loss Special Form) regardless of whether or not, or in what amounts, such insurance is now or hereafter carried by the Parties, or either of them. Customer agrees that Xcel Energy self-insures against any loss or damage which could be covered by a commercial general public liability insurance policy and or a property policy. **Customer shall give written notice of this mutual waiver to each insurance company which issues insurance policies to Customer with respect to the items covered by this waiver, and shall have Customer's insurance policies properly endorsed, if necessary, to prevent the invalidation of any of the coverage provided by such insurance policies by reason of such waiver.**
- Damage to the Site or personal property that appears to be caused by an Xcel Energy-owned Charger under the EV Accelerate At Home Program or a faulty hardwired connection between the Charger and Premise Wiring, for which Work was performed by Xcel Energy or an Xcel Energy sub-contractor, should be reported to Xcel Energy through the Xcel Energy claims process, which can be found on Xcel Energy's website. Upon receipt of your claim, Xcel Energy will involve the appropriate vendors, contractors, or manufacturers in the investigation and resolution. Xcel Energy, and its contractors and suppliers, are not responsible for damage caused by faulty Premise Wiring, damage due to misuse or neglect of the Charging Equipment, or which are caused by fire, flood, or other natural disaster; such damage will be the sole and entire responsibility of Customer and its contractors. N

N

(Continued on Sheet No. 7-121)

~~**7. Indemnification**~~ L

- ~~To the extent permitted by applicable law (but except to the extent waived in Section 10 below), each Party shall indemnify and hold the other Party harmless against any third party claim of liability or loss from bodily injury (including mental or emotional or death of any person) or property damage (real, personal, tangible or intangible including without limitation real or personal property of any third party, the Charging Equipment and any associated Equipment hardware) resulting from or arising out of the use of the Site by the Party, its servants or agents, except however, such claims or damages as may be due to or caused by the acts or omissions of the other Party, its servants, or agents.~~ L

(Continued on Sheet No. 7-121)

7. Indemnification L

- To the extent permitted by applicable law (but except to the extent waived in Section 10 below), each Party shall indemnify and hold the other Party harmless against any third party claim of liability or loss from bodily injury (including mental or emotional or death of any person) or property damage (real, personal, tangible or intangible including without limitation real or personal property of any third party, the Charging Equipment and any associated Equipment hardware) resulting from or arising out of the use of the Site by the Party, its servants or agents, except however, such claims or damages as may be due to or caused by the acts or omissions of the other Party, its servants, or agents. L

8. Warranty

- 8.1 Xcel Energy warrants that Charging Equipment work performed by Xcel Energy's network of authorized Third party independent contractors will be free from defects in materials and workmanship during the Term of the Agreement.

  In the event that any Charging Equipment work performed is found to be defective in either materials or workmanship, Xcel Energy shall repair or replace such defective Equipment or work. The repair or replacement of such defective work is Customer's sole and exclusive remedy under this warranty for any failure of Xcel Energy to comply with Xcel Energy's Warranty Obligations, and Xcel Energy expressly disclaims any and all other warranties including any warranties of merchantability or fitness for a particular purpose, whether expressed or implied. For avoidance of doubt, repair, or replacement of non-conformities in the manner and for the period of time provided above shall constitute Xcel Energy's sole liability and the Customer's exclusive remedy for failure of Xcel Energy to meet Xcel Energy's warranty obligations, whether any claims of host are based in contract, in tort (including negligence or strict liability), or otherwise.

9. Limits of Liability

A. Notwithstanding anything herein to the contrary, under no circumstances or legal theory, whether arising in contract, tort, strict liability, warranty, infringement or otherwise, shall either party be liable to the other party or any other person or entity for any indirect, consequential, secondary, incidental, special, reliance, exemplary or punitive damages, which includes but is not limited to: i) any property damage (real, personal, tangible or intangible) or personal injury (including mental or emotional distress) arising from or alleged to have arisen under this agreement; ii) any claims or causes of action that arise or are alleged to have arisen as a result of any required space ventilation not made known in writing to Xcel Energy or Xcel Energy's authorized third party independent contractor in writing prior to any work; iii) any damages arising or alleged to have arisen from any electrical malfunction or the repair or replacement of such malfunctioning items; or iv) any environmental claims, damage or causes of action.

B. Under no circumstances will Xcel Energy or any Xcel Energy authorized third party independent contractor be held liable to Customer or any other person or entity for matters involving the purchase, lease, use, non-use, or devaluation of any electric vehicle, plug-in hybrid vehicle or any vehicle of any nature, any Charging Equipment or associated equipment infrastructure when applicable codes or standards prohibit the installation or use of such vehicle or Equipment. Xcel Energy will not pay for any costs incurred or damages sustained by customer for purchasing any vehicle or Equipment or otherwise in reliance upon Xcel Energy being able to provide a Charger to customer. Notwithstanding anything set forth in this agreement to the contrary, under no circumstances shall Xcel Energy's total liability under this agreement exceed the total cost of the Charging Equipment plus installation costs made by Xcel Energy under this agreement. This section shall survive the termination of this agreement.

(Continued on Sheet No. 7-122)

Clean

AVAILABILITY C

Available to Residential Service customers for service only to electric vehicle loads including battery charging and accessory usage. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service with this tariff. Pre-Pay Option service is closed and not available to new customers. BYOC Option service is available to customers electing to bring their own charging equipment as approved by the Company, prior to beginning service with this tariff. The customer must possess, through ownership or lease, an electric vehicle, meaning any device or contrivance that transports persons or property and that is able to be powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electricity. Electric vehicle includes, but is not limited to, an electric vehicle as defined in Minnesota Statues Section 169.011, subdivision 26a; an electric-assisted bicycle as defined in Section 169.011, subdivision 27; an off-road vehicle, as defined in Section 84.797, subdivision 7; a motorboat, as defined in Section 86B.005, subdivision 9; or an aircraft, as defined in Section 360.013, subdivision 37.

CONTRACT

Customers must contract for this service through an EV Accelerate At Home Customer Service Agreement with the Company. The contract period will be as long as the customer wishes to use the equipment. Customers who initially contracted for the Residential Electric Vehicle Subscription Pilot Service through an Electric Vehicle Subscription Pilot Electric Service Agreement can still take service under that agreement through the 36-month term. At the end of that agreement, the customer can continue service by contracting for the service through an EV Accelerate At Home Customer Service Agreement or terminate their service at no cost to them. Contract allows customers to participate with more than one electric vehicle.

C

CHARACTER OF SERVICE

Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION

Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable*Connect Pilot Program (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable. T

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer’s Expected Average Electric Vehicle kWh Usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer’s kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and /or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

(Continued on Sheet No. 5-8.2)

RATE

Customer Charge per Month (Up to 1,000 kWh of off-peak charging per month) N

General System Energy		
Bundled (A82)	$48.80	R
Pre-Pay Option (A83) (Closed)	$38.02	CR
BYOC (A84)	$38.81	N
Renewable Energy (Windsource)		
Bundled (A82)	$49.93	R
Pre-Pay Option (A83) (Closed)	$39.15	CR
BYOC (A84)	$39.94	N

Excess On-Peak Period Energy Charge per kWh

June - September	$0.20497	
Other Months	$0.16508	

Excess Off-Peak Energy Charge per kWh (above 1,000 kWh per month) N

All Months	$0.04170	N

PRE-PAY OPTION (CLOSED) C

The Pre-Pay Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company.

BYOC OPTION N

Customers choosing the BYOC Service are required to utilize a vehicle charger model that is approved by the Company for use for this rate. Customers choosing the BYOC Service are required to have a Company-contracted electrician perform a site visit to install and hardwire the charging equipment, if needed, or to confirm equipment eligibility and equipment set up to ensure program compatibility. The cost of the site visit is included in the monthly customer charge. Customers choosing the BYOC Service are required to utilize a vehicle charger model that is approved by the Company for use for this rate. N

INTERIM RATE ADJUSTMENT

An 8.92% Interim Rate Surcharge will be applied to rate components specified in the "Interim Rate Surcharge Rider" to service provided beginning January 1, 2022.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE

The monthly customer charge includes preset fuel charges for established energy usage during off-peak and on-peak periods. Excess on-peak period energy charges are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT

The monthly customer charge includes a preset Resource Adjustment charge for established energy usage during off-peak and on-peak periods. Excess on-peak period energy charges are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-8.3)

MONTHLY MINIMUM CHARGE L
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5. L

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF EXPECTED AVERAGE ELECTRIC VEHICLE KWH USAGE
The expected average electric vehicle kWh usage is defined as the Company's estimated average monthly EV energy consumption across all pilot participants.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs D
associated with electric vehicles. D

TERMS AND CONDITIONS OF SERVICE
1. Residential EV Accelerate At Home Subscription Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage. T
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access to charging equipment for the recording and wireless communication of energy usage. C
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an EV Accelerate At Home Customer Service Agreement with the Company. T

EV Home Service Offerings

Rate Options	Customer upfront out-of-pocket expenses	Customer monthly charge for EV Home Service	Services included in monthly charge for EV Service	Monthly usage billed
Bundled Residential EV Accelerate At Home Pay As You Go Subscription Service Rate Code: A82	• Premises wiring	$48.80	•Charging Equipment and installation •Customer services •Customer accounting •Load monitoring and data management •Maintenance service •Charging Equipment removal and relocation	EV Charging is billed according to Rate Code A82
BYOC Residential EV Accelerate At Home Pay As You Go Service Rate Code: A84	• Premises wiring	$38.81	•Charging equipment installation (initial electrician visit) •Customer services •Customer accounting •Load monitoring and data management	EV Charging is billed according to Rate Code A84

(Continued on Sheet No. 7-114)

XCEL EV Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement (Continued)

In order to enroll in the Program, please review these terms and indicate your understanding and agreement below by selecting the appropriate check box on the Program enrollment page at [link to be generated at xcelenergy.com]. Once enrolled, Xcel Energy will arrange to have a qualified technician install the Charging Equipment at your Site or, if a BYOC participant, perform the initial electrician visit to ensure the equipment meets the program equipment requirements. When installation or visit is complete, Xcel Energy will notify you that the Charger is operational and activated, by e-mail (the date of the e-mail will be the "Activation Date"). C C

Definitions
"Electric Vehicle," defined in Section 169.011, subdivision 26a of Minnesota law, means a motor vehicle that is able to be powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electric current, and meets or exceeds applicable regulations in the Code of Federal Regulations, title 49, part 571. Electric vehicles include neighborhood electric vehicles, medium-speed electric vehicles, and plug-in hybrid electric vehicles.

"Charging Equipment, or Charger, or Equipment" means the installed device used to deliver electricity from the Premises Wiring to the electric vehicle, meeting Standard J1772 of the Society of Automotive Engineers International and listed under applicable UL Standards and requirements or equivalent listing by a nationally recognized testing laboratory. This device includes the ungrounded, grounded, and Equipment grounding conductors, the Electric Vehicle connectors, attachment plugs, and all other fittings, devices, power outlets or apparatuses associated with the installed device, but does not include Premises Wiring.

"Premises Wiring" means a dedicated 208/240V AC circuit that supplies electricity directly to the installed Charging Equipment. This includes the protective breaker at the supply panel, wiring, final junction box, receptacle and all attachments and connections. The Customer retains ownership and is wholly responsible for the Premises Wiring, including that it meets all workmanship standards and applicable requirements in the National Electric Code, Minnesota law and Administrative Rules, and local municipal codes.

"Site" means the enclosed garage or other area approved by Xcel Energy on property owned or rented by the Customer as the Customer's dwelling.

(Continued on Sheet No. 7-115)

1. Eligibility and Availability

To be eligible for the EV Accelerate At Home Program (Rate Codes A79, A80), Customers must: T

- have an active Xcel Energy electric service account in Minnesota with no past due bills, disconnection notices, or pay arrangements; C C
- rent or own their dwelling, provided that Customers who are renting their dwelling have a separately metered service, are willing to pay for any necessary make-ready infrastructure, and have the building owner's written consent to participate in the EV Home Service;
- represent that the Site is owned by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with a Xcel Energy residential electrical account on which the Charger will be installed;
- complete Xcel Energy-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on its behalf, for the exclusive use of tracking the energy used to charge their electric vehicle;
- have wireless internet ("Wi-Fi") service at Site;
- not be on current Residential EV Service Rate (Rate Code A08). If participant is already enrolled, they must unenroll for the duration of their participation on the EV Home Service Program; T
- not participate in the Time of Use Rate Design Pilot Program. If the Customer is already enrolled, they must unenroll for the duration of their participation in the EV Home Service; and
- not participate in the Company's Net Metering tariffs.

To be eligible for the EV Accelerate At Home Program Voluntary Electric Service (Rate Code A76), Customers must: T T

- have an active Xcel Energy electric service account in Minnesota with no past due bills, disconnection notices, or pay arrangements;
- rent or own their dwelling, provided that Customers who are renting their dwelling have a separately metered service, are willing to pay for any necessary make-ready infrastructure, and have the building owner's written consent to participate in the Voluntary Electric Vehicle Charger Service;
- represent that the Site is owned by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with an Xcel Energy residential electrical account on which the Charger will be installed;
- complete Xcel Energy-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on its behalf, for the exclusive use of tracking the energy used to charge their electric vehicle; and
- have Wi-Fi service at Site;
- be on a current Residential Time of Day rate (Rate Codes A02 and A04). T

(Continued on Sheet No. 7-115.1)

To be eligible for the EV Accelerate At Home Subscription Program (Rate Codes A82, A84), Customers must: N

- Agree to the terms and conditions of this Services Agreement;
- Have an active Xcel Energy residential electric service account in Xcel Energy's Minnesota regulated electric service territory with no past due bills, disconnection notices, or pay arrangements;
- rent or own the Site, provided that if you rent the Site, you must have a separately metered service, pay for any necessary Premises Wiring, and have the Site owner's written consent to participate in the EV Accelerate At Home Program;
- represent that the Site is owned or rented by the Customer, is located within Xcel Energy's Minnesota regulated electrical service territory, and corresponds with a Xcel Energy residential electrical account on which the Charger will be installed;
- have an approved Charger installed by Xcel Energy, or an authorized third-party independent contractor on Xcel Energy's behalf, or be inspected and confirmed as eligible by an Xcel Energy contracted electrician, for the exclusive use of tracking the electricity used to charge your Electric Vehicle;
- have wireless internet ("Wi-Fi") service at Site;
- not be on current Xcel Energy Residential EV Service Rate (Rate Code A08). If you are already enrolled on Rate Code A08, you must unenroll for the duration of your participation in the EV Accelerate At Home Program;
- not participate in the Residential Time of Day Service Rate (Rate Codes A02, A04); if Participant is already enrolled, they must unenroll for the duration of their participation in the EVAAH Subscription Program;
- not participate in the EVAAH Pay-As-You-Go (Rate Codes A80, A81);
- not participate in the Time of Use Rate Design Pilot Program; if Participant is already enrolled, they must unenroll for the duration of their participation in the EVAAH Subscription Program; and
- not participate in the Company's Net Metering tariffs. N

(Continued on Sheet No. 7-116)

3. Customer's CHARGING EQUIPMENT Obligations and Duties
Throughout the Term of this Agreement:

- 3.1 Customer shall grant to Xcel Energy such access to the Site and sufficient space for locating the Charging Equipment at the Site as may be deemed necessary or desirable by Xcel Energy for the Work. Installations must conform to the Company's specifications.

- 3.2 Customer shall be responsible for the expense and installation of any Premises Wiring necessary to provide electricity to the Charging Equipment. Customer may, in Customer's sole discretion, opt to use Xcel Energy's third-party independent contractor to install the necessary Premises Wiring in addition to the Charging Equipment, provided that Customer will be responsible for the expense to have the third-party independent contractor install the Premises Wiring.

- 3.3 Until the Charging Equipment (in Xcel Energy's sole discretion) is deemed non-functional or this Agreement is terminated, the Customer hereby consents to and shall permit both Xcel Energy and any underlying equipment manufacturer, vendor or subcontractor to the underlying manufacturer or vendor to access, collect and share with their respective parent, affiliates, subsidiaries and subcontractors all data from the Charger with respect to vehicle charging activity, vehicle usage and technical performance (the "Data") of the vehicle and Charger. Xcel Energy shall comply with all federal, state, and local laws, as applicable, in the access, collection, and sharing of the Data. In the event the Charger fails to operate or otherwise require repair, the Customer shall promptly notify Xcel Energy.

- 3.4 If you are enrolled in Bundled EVAAH Pay As You Go or Bundled EVAAH Subscription Pay As You Go and are experiencing issues with the Charger at the Site, in addition to contacting Xcel Energy, you must contact the Charging Equipment manufacturer to diagnose Charger performance issues. The contact information for the Charging Equipment manufacturer may be found on Xcel Energy's website. You may also contact Xcel Energy as provided below for the Charging Equipment manufacturer's contact information. Xcel Energy will not be able to correct problems with a Charger until Xcel Energy has received the Charging Equipment manufacturer's diagnosis of the problem. If the Charging Equipment manufacturer is unable to remedy the issue with the Charger during remote diagnostics, Xcel Energy will work with the Charging Equipment manufacturer to determine the necessary remedial actions, which may include replacing the defective Charger or sending an Xcel Energy electrician to the Site for further diagnosis. If the Charger manufacturer determines the Charger is damaged due to misuse or neglect, Xcel Energy will be notified and you will be responsible for purchasing the Charger at the Charging Equipment Buyout Amount. Xcel Energy will provide you an invoice in the amount of the Charging Equipment Buyout Amount and you agree to pay such amount within thirty days of your receipt of such invoice. Upon Xcel Energy's receipt of your payment of the Charging Equipment Buyout Amount, this Service Agreement and your participation in EV Accelerate At Home Program will automatically terminate and Xcel Energy will transfer title to the Charging Equipment on an "As-Is" basis, with no warranty of any kind, express or implied. Upon such termination, you will be responsible for any necessary maintenance, repair, or replacement of the Equipment. N

- 3.5 If your Charger has been subject to fire, flood, or other natural disaster, the Charging Equipment manufacturer and Xcel Energy will need to verify that the Charger is functional and safe for continued use in the EV Accelerate At Home Program. In the event of such fire, flood or other natural disaster, you must contact the Charging Equipment manufacturer and Xcel Energy. The Charging Equipment manufacturer will help determine if your Charger is communicating properly following the fire, flood or natural disaster. If enrolled in Bundled EVAAH Pay As You Go or Bundled EVAAH Subscription Pay As You Go and the Charging Equipment manufacturer N

(Continued on Sheet No. 7-117.1)

determines the Charger is still functioning and communicating properly, before continued use of the Charger under the EV Accelerate At Home Program, an Xcel Energy electrician will need to inspect the connectors, pins, and cable for damage to verify that the Charger is safe and functioning properly. If the Xcel Energy electrician determines that the Charger is safe and functioning, the Charger may continue to be enrolled in the EV Accelerate At Home Program. However, in the event the Charger is deemed by Xcel Energy to be unsafe and/or nonfunctional due to a flood, fire or other natural disaster, you will be responsible for purchasing the Charger at the Charging Equipment Buyout Amount. Xcel Energy will provide you an invoice in the amount of the Charging Equipment Buyout Amount and you agree to pay such amount within thirty days of your receipt of such invoice. Upon Xcel Energy's receipt of your payment of the Charging Equipment Buyout Amount, this Service Agreement and your participation in EV Accelerate At Home Program will automatically terminate and Xcel Energy will transfer title to the Charging Equipment on an "As-Is" basis, with no warranty of any kind, express or implied. Please contact Xcel Energy for copies of statements reflecting the Charging Equipment Buyout Amount for your insurance provider, if needed. N N

- 3.5 Customer, Xcel Energy and its authorized equipment manufacturers, vendors, and subcontractors shall comply with all applicable rules and regulations of federal, state or city regulatory agencies relating to the Work and operation of the Charger, including environmental requirements associated therewith. LT

- 3.6 Customer shall maintain the area surrounding the Charging Equipment and will promptly notify Xcel Energy of any problems related to the Equipment that the Customer becomes aware of. Such maintenance includes, but is not limited to, pavement maintenance, pruning of vegetation, and snow removal. For avoidance of doubt, Customer is not responsible for the ongoing maintenance of the Equipment, itself. T

- 3.7 Customer agrees to remedy minor issues that do not require qualified technicians to address, such as resetting infrequently tripped circuit breakers. T

- 3.8 Customer agrees to provide access and assistance to facilitate random Charging Equipment testing, if selected. Such cooperation may include, but not be limited to, periodic inspection of the Charger and the addition of monitoring hardware or software at Xcel Energy's expense. T

- 3.9 Customer agrees to participate in surveys and provide feedback about the Program as well as cooperate with Xcel Energy in fulfilling Xcel Energy's reporting requirements to any federal, state or local regulatory or governing entities. T L

(Continued on Sheet No. 7-118)

- 4.8 Xcel Energy, in its sole discretion, may terminate the Agreement at any time, in which case Xcel Energy will provide Customers paying the bundled service customer charge with sixty (60) days' prior written notice of its intent to terminate the Agreement and remove the Charging Equipment. For Customers paying the prepay service customer charge, Xcel Energy will provide the Customers with sixty (60) days' prior written notice of its intent to terminate the Agreement and transfer ownership of the Charging Equipment to the Customer at no cost. For Customers using the Installation-Only Service, Xcel Energy will provide the Customers with sixty (60) days' prior written notice of its intent to terminate the Agreement. The Customers may continue using the Charging Equipment after termination, before it is transferred or removed, as applicable.

5. Title to Equipment and Data

- At all times under this Agreement where Xcel Energy shall own and maintain title to the Charging Equipment, the Customer shall not make any alterations, changes or modifications to the Charger without first securing prior written permission from Xcel Energy and/or any applicable underlying manufacturer. All rights, title and interest in the Equipment Data and related information collected from the Equipment shall also immediately vest in Xcel Energy.

  Xcel Energy shall therefore have the right to use, copy, and distribute such Data and information as necessary and helpful to evaluate electric vehicles and electric vehicle support equipment and for any other Xcel Energy business purpose. To the extent applicable, Xcel Energy shall indemnify and hold harmless the Customer from any and all claims whatsoever for the use and distribution of said Data.

6. Insurance Coverage

- Customer shall have in full force and effect a standard fire and homeowner's insurance policy with amounts sufficient to cover the full replacement cost of the Site. The Parties hereby waive any and all claims and rights of action (by way of subrogation or otherwise) against the other (and against any insurance company insuring the other Party) which may hereafter arise on account of bodily injury or damage to the Charging Equipment or to the Site, resulting from any fire, or other perils or claims of the kind covered by standard fire and homeowner's insurance policies with extended coverage (Causes of Loss Special Form) regardless of whether or not, or in what amounts, such insurance is now or hereafter carried by the Parties, or either of them. Customer agrees that Xcel Energy self-insures against any loss or damage which could be covered by a commercial general public liability insurance policy and or a property policy. **Customer shall give written notice of this mutual waiver to each insurance company which issues insurance policies to Customer with respect to the items covered by this waiver, and shall have Customer's insurance policies properly endorsed, if necessary, to prevent the invalidation of any of the coverage provided by such insurance policies by reason of such waiver.**
- Damage to the Site or personal property that appears to be caused by an Xcel Energy-owned Charger under the EV Accelerate At Home Program or a faulty hardwired connection between the Charger and Premise Wiring, for which Work was performed by Xcel Energy or an Xcel Energy sub-contractor, should be reported to Xcel Energy through the Xcel Energy claims process, which can be found on Xcel Energy's website. Upon receipt of your claim, Xcel Energy will involve the appropriate vendors, contractors, or manufacturers in the investigation and resolution. Xcel Energy, and its contractors and suppliers, are not responsible for damage caused by faulty Premise Wiring, damage due to misuse or neglect of the Charging Equipment, or which are caused by fire, flood, or other natural disaster; such damage will be the sole and entire responsibility of Customer and its contractors. N N

(Continued on Sheet No. 7-121)

7. Indemnification L

- To the extent permitted by applicable law (but except to the extent waived in Section 10 below), each Party shall indemnify and hold the other Party harmless against any third party claim of liability or loss from bodily injury (including mental or emotional or death of any person) or property damage (real, personal, tangible or intangible including without limitation real or personal property of any third party, the Charging Equipment and any associated Equipment hardware) resulting from or arising out of the use of the Site by the Party, its servants or agents, except however, such claims or damages as may be due to or caused by the acts or omissions of the other Party, its servants, or agents. L

8. Warranty

- 8.1 Xcel Energy warrants that Charging Equipment work performed by Xcel Energy’s network of authorized Third party independent contractors will be free from defects in materials and workmanship during the Term of the Agreement.

  In the event that any Charging Equipment work performed is found to be defective in either materials or workmanship, Xcel Energy shall repair or replace such defective Equipment or work. The repair or replacement of such defective work is Customer’s sole and exclusive remedy under this warranty for any failure of Xcel Energy to comply with Xcel Energy’s Warranty Obligations, and Xcel Energy expressly disclaims any and all other warranties including any warranties of merchantability or fitness for a particular purpose, whether expressed or implied. For avoidance of doubt, repair, or replacement of non-conformities in the manner and for the period of time provided above shall constitute Xcel Energy’s sole liability and the Customer’s exclusive remedy for failure of Xcel Energy to meet Xcel Energy’s warranty obligations, whether any claims of host are based in contract, in tort (including negligence or strict liability), or otherwise.

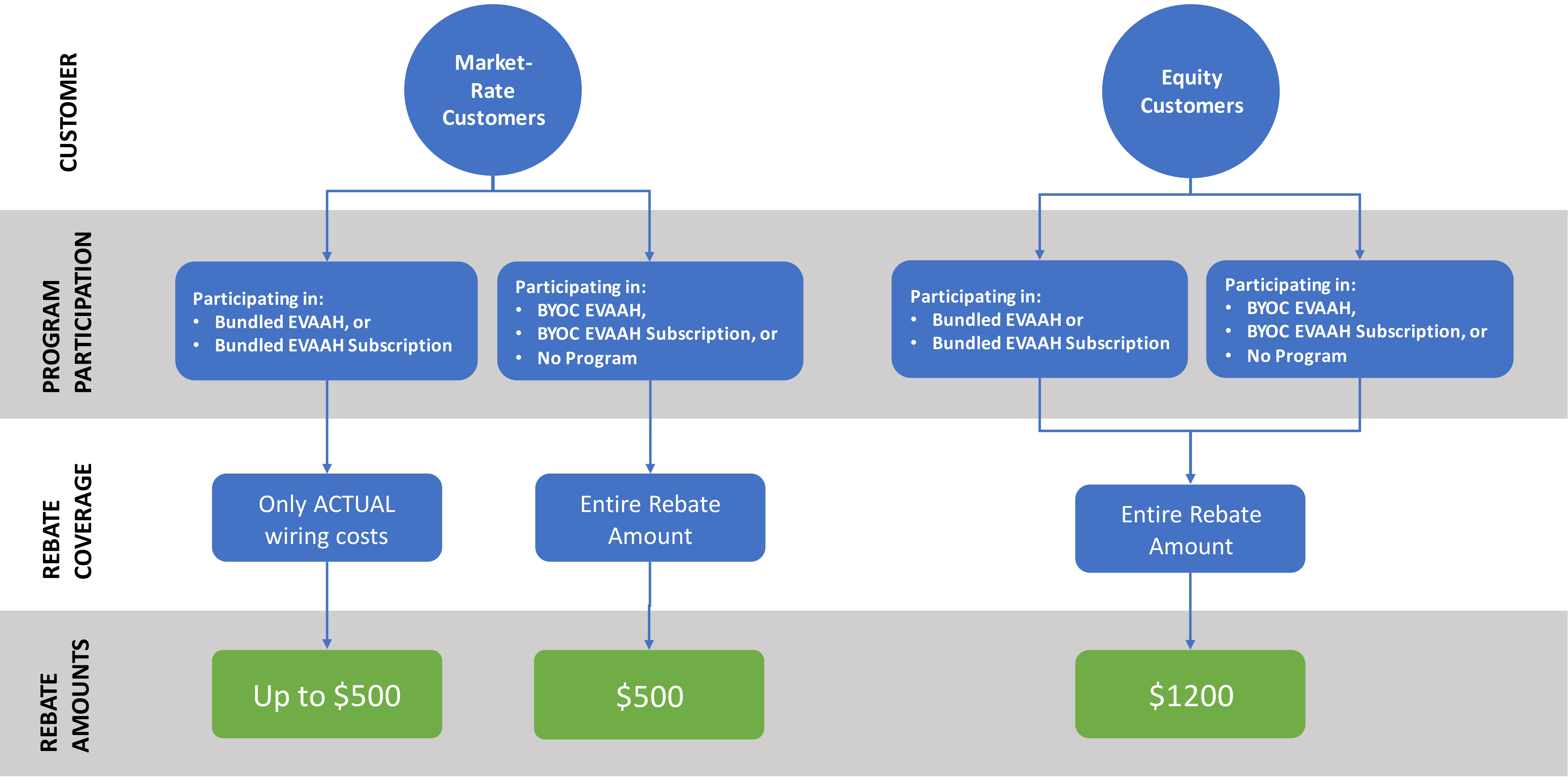
9. Limits of Liability

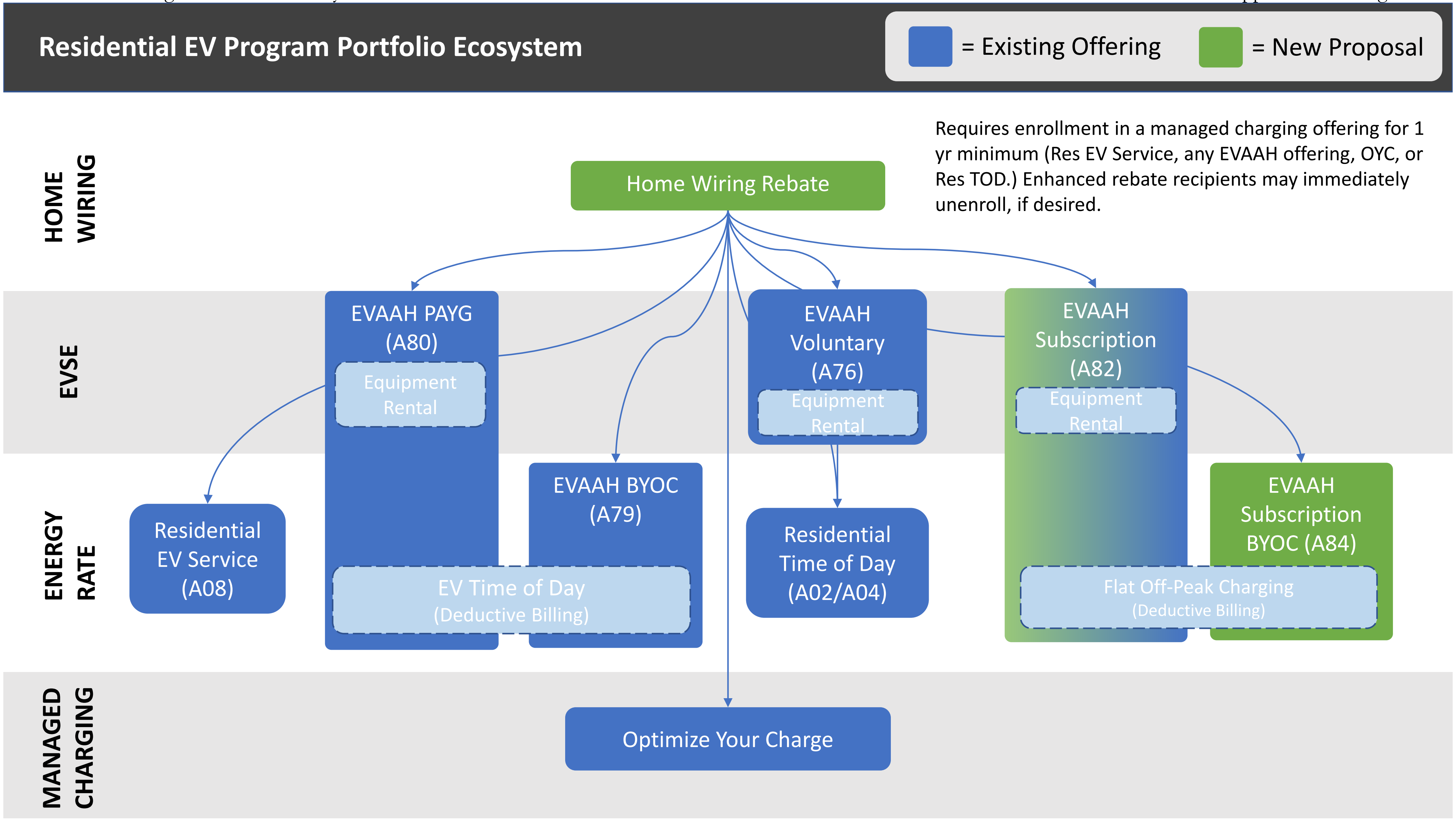
A. Notwithstanding anything herein to the contrary, under no circumstances or legal theory, whether arising in contract, tort, strict liability, warranty, infringement or otherwise, shall either party be liable to the other party or any other person or entity for any indirect, consequential, secondary, incidental, special, reliance, exemplary or punitive damages, which includes but is not limited to: i) any property damage (real, personal, tangible or intangible) or personal injury (including mental or emotional distress) arising from or alleged to have arisen under this agreement; ii) any claims or causes of action that arise or are alleged to have arisen as a result of any required space ventilation not made known in writing to Xcel Energy or Xcel Energy's authorized third party independent contractor in writing prior to any work; iii) any damages arising or alleged to have arisen from any electrical malfunction or the repair or replacement of such malfunctioning items; or iv) any environmental claims, damage or causes of action.

B. Under no circumstances will Xcel Energy or any Xcel Energy authorized third party independent contractor be held liable to Customer or any other person or entity for matters involving the purchase, lease, use, non-use, or devaluation of any electric vehicle, plug-in hybrid vehicle or any vehicle of any nature, any Charging Equipment or associated equipment infrastructure when applicable codes or standards prohibit the installation or use of such vehicle or Equipment. Xcel Energy will not pay for any costs incurred or damages sustained by customer for purchasing any vehicle or Equipment or otherwise in reliance upon Xcel Energy being able to provide a Charger to customer. Notwithstanding anything set forth in this agreement to the contrary, under no circumstances shall Xcel Energy’s total liability under this agreement exceed the total cost of the Charging Equipment plus installation costs made by Xcel Energy under this agreement. This section shall survive the termination of this agreement.

(Continued on Sheet No. 7-122)

Overview of Home Wiring Rebate Amount




Residential EV Program Portfolio Ecosystem
= Existing Offering
= New Proposal
HOME WIRING
EVSE
ENERGY RATE
MANAGED CHARGING
Home Wiring Rebate
Requires enrollment in a managed charging offering for 1 yr minimum (Res EV Service, any EVAAH offering, OYC, or Res TOD.) Enhanced rebate recipients may immediately unenroll, if desired.
EVAAH PAYG (A80)
Equipment Rental
EVAAH Voluntary (A76)
Equipment Rental
EVAAH Subscription (A82)
Equipment Rental
EVAAH BYOC (A79)
Residential EV Service (A08)
EV Time of Day (Deductive Billing)
Residential Time of Day (A02/A04)
EVAAH Subscription BYOC (A84)
Flat Off-Peak Charging (Deductive Billing)
Optimize Your Charge

Responses to February 1, 2019 Commission Order (Docket No. E999-M-17-879)

a. Environmental justice, with a focus on communities disproportionately disadvantaged by traditional fossil fuel use	To the extent possible, the selection process for demonstration participants will give priority to bus operators and school districts that serve low-income, BIPOC, and rural communities. Low-income and BIPOC students are disproportionately impacted by diesel emissions and air pollution. Research shows that more low-income students take the bus when compared to non-low-income students. Research also shows that Latino, African American, and Asian American students are exposed to particulate matter from on-road sources at higher rates than students not in those groups. Finally Native American students are disproportionately impacted by air pollution and experience higher childhood asthma rates then other students.
b. Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options	The school bus demonstration is designed to give priority to bus operators and school districts that serve low-income communities, BIPOC communities, and rural communities.
c. Environmental benefits, including, but not limited to carbon and other emission reductions	The purpose of this demonstration is to study vehicle-to-grid (V2G) applications as they apply to electric school buses. V2G has the potential to mitigate constraints on the electric grid when serving as a grid resource and can help to enable greater renewable energy resource penetration. The project will help evaluate whether V2G can be an additional value stream associated with school bus electrification, thereby accelerating electric school bus adoption, and the value of V2G as a grid resource. The Company believes this demonstration can provide learnings for future efforts to inform additional environmental benefits from V2G, scale V2G deployment economically, and to bring environmental benefits associated with increasing adoption of electric school buses in conjunction with the Department's electric school bus deployment program.
d. Potential economic development and employment benefits in Minnesota	The demonstration is not designed to address this issue. The Company will use local contractors to complete all the EV supply infrastructure and charging equipment installations.

e. Interoperability and open charging standards	The Company will work with electric school buses and vehicle-to-grid (V2G) charging equipment manufacturers to ensure compatibility with the operator-selected school bus makes and models. During this coordinated process, the Company will assess the equipment's compliance with standards such as Open Charge Point Protocol and OpenADR.
f. Load management capabilities, including the use of demand response in charging equipment or vehicles	All electric school buses and charging equipment procured and deployed in this demonstration will be V2G capable to facilitate load management demonstrations. Further, demonstration participants will be required to take charging service under the Fleet EV Service Pilot which features energy charges that encourage off-peak charging.
g. Energy and capacity requirements	Energy and capacity information for the demonstration will be reported in our applicable annual reports and proposed quarterly reporting. We expect the requirement of participants to take service on time varying rates along with the facilitation of V2G demonstrations will push the capacity requirement outside of the Company's system peak.
h. Pilot expansion and/or transition to permanent status at greater scale	The Company is using the demonstration to assess the effectiveness of offering future options for deploying electric school buses and associated charging infrastructure. The learnings gathered in this demonstration will be used to assess the viability of a future expansion of school bus offerings, likely in conjunction with the Department's electric school bus deployment program. The Company intends to file a supplement in 2024 with additional transportation electrification proposals. Included in that supplement will likely be an expanded electric school bus and V2G offering.
i. Education and outreach	The Company's demonstration administration team will work with the Department and their school bus program to find and select interested school districts and school bus operators which whom to complete a demonstration application and to become participants in the program.
j. Market competitiveness/ ownership structures	The demonstration is designed to work in partnership with school bus operators to effectively deploy electric school buses through their traditional full-service operating model that exists today. The school districts and/or school bus operators will purchase and procure the buses and chargers from the manufacturers or other appropriate sources and coordinate a timeline and plan for delivery to coincide with the Company's installation of the charging

	infrastructure. The Company will provide a rebate for the participants' eligible charger. The electric school bus segment is in a nascent stage of development and overall adoption, and the demonstration will bring the available bus and charging equipment options to this segment.
k. Distribution system impacts	Due to its size, we do not expect this demonstration to have a significant impact on the distribution system. However, the Company will measure distribution and grid system needs and constraints and quantify the effects of V2G on the distribution system from electric school bus charging events.
l. Costs and benefits of the proposal	Part of the information we will gather is the cost of providing this type of service to a new charging segment. We provide a high-level discussion of benefits we see within the demonstration in the Cost-Benefits section of the Transportation Electrification Plan (Appendix H, Section III.C).
m. Customer data privacy and security	The Company has designed its proposal to meet legal and regulatory requirements concerning data privacy and security.
n. Evaluation metrics and reporting schedule	We propose a list of evaluation metrics in Section III.A.3.c of the Transportation Electrification Plan (Appendix H). We intend to file the information we gather in our both Annual EV Report, filed each year on June 1 as well as in our quarterly EV Reports.

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

[PROTECTED DATA BEGINS

Application Type	Status	Project / Customer Name	Charging Ports	Application Date	Agreement Status	Agreement Executed	Estimated Distribution Cost	Estimated EVSI Cost	Estimated EVSE Cost	Estimated Total Forecast	EJ Area of Concern?
Fleet	Ready	City of Minneapolis - 2632 Hiawatha Ave	11	5/10/2023	Completed by Customer	4/12/2023	$42,894	$241,887	$0	$284,780	Yes
Public Charging	Ready	Mercedes Benz St. Paul - Morrie's Auto Group	2	5/31/2023	Completed by Customer	6/15/2023	$31,622	$119,797	$0	$151,419	Yes
Public Charging	Ready	Apple Chevrolet- Northfield	2	5/15/2023	Completed by Customer	5/19/2023	$16,360	$87,004	$0	$103,364	No
Public Charging	Ready	Red Wing Chevrolet	2	4/28/2023	Completed by Customer	4/28/2023	$31,622	$119,797	$0	$151,419	No
Public Charging	Ready	ZEF Energy-City of La Crescent	4	6/9/2023	Sent	NA	$32,720	$174,007	$0	$206,727	No
Public Charging	Ready	Park Chrysler Jeep	2	5/29/2023	Completed by Customer	5/29/2023	$31,622	$119,797	$0	$151,419	Yes
Public Charging	Ready	A.M. Maus and Son - Chrysler Dodge Jeep Ram	2	5/3/2023	Completed by Customer	5/15/2023	$31,622	$119,797	$0	$151,419	No
Public Charging	Ready	Dodge of Burnsville Inc	2	5/29/2023	Completed by Customer	5/29/2023	$31,622	$119,797	$0	$151,419	Yes
Public Charging	Ready	Mankato Motor Company	3	5/16/2023	Completed by Customer	5/16/2023	$32,171	$146,902	$0	$179,073	Yes
Public Charging	Ready	Philip Edison - EMC	8	6/1/2023	Sent	NA	$34,916	$282,428	$0	$317,344	Yes
Public Charging	Ready	Scandia Electric INC	2	5/31/2023	Completed by Customer	5/29/2023	$31,622	$119,797	$0	$151,419	No
Public Charging	Ready	Country Chevrolet	4	6/9/2023	Completed by Customer	6/9/2023	$32,720	$174,007	$0	$206,727	Yes
Public Charging	Ready	Lupient Chevrolet of Bloomington	4	5/12/2023	Completed by Customer	5/12/2023	$32,720	$174,007	$0	$206,727	Yes
Public Charging	Ready	Metropolitan Ford	12	5/11/2023	Completed by Customer	3/30/2023	$98,160	$522,022	$0	$620,182	No
Fleet	Likely	City of Saint Paul	6	TBD	TBD	TBD	$21,688	$103,579	TBD	$125,267	Yes
Fleet	Likely	City of Saint Paul Parking Garage	2	TBD	TBD	TBD	$7,229	$34,526	TBD	$41,756	Yes
Fleet	Likely	City of Saint Paul Parks	6	TBD	TBD	TBD	$21,688	$103,579	TBD	$125,267	Yes
Fleet	Likely	City of Saint Paul PD East District	4	TBD	TBD	TBD	$14,459	$69,053	TBD	$83,511	Yes
Fleet	Likely	City of Saint Paul PD West District	4	TBD	TBD	TBD	$14,459	$69,053	TBD	$83,511	Yes
Fleet	Likely	City of Saint Paul Police HQ	20	TBD	TBD	TBD	$72,293	$345,263	TBD	$417,555	Yes
Fleet	Likely	City of Saint Paul Sewer	2	TBD	TBD	TBD	$7,229	$34,526	TBD	$41,756	Yes
Fleet	Likely	City of Saint Paul Zoo Campus	4	TBD	TBD	TBD	$14,459	$69,053	TBD	$83,511	Yes
Fleet	Likely	City of Saint Paul Fire Station 7	4	TBD	TBD	TBD	$20,724	$173,037	TBD	$193,761	Yes
Public Charging	Likely	Brookdale Library - Hennepin County	10	TBD	TBD	TBD	$66,538	$402,225	$0	$468,763	Yes
Public Charging	Likely	City of Cottage Grove	4	TBD	TBD	TBD	$32,720	$174,007	$0	$206,727	No
Public Charging	Likely	City of Sartell	4	TBD	TBD	TBD	$32,720	$174,007	$0	$206,727	Yes
Public Charging	Likely	McKay's Dodge Chrysler Jeep Ram	6	TBD	TBD	TBD	$33,818	$228,218	$0	$262,036	Yes
Public Charging	Likely	ZEF Energy	4	TBD	TBD	TBD	$32,720	$174,007	$0	$206,727	Yes
Public Charging	Likely	Room & Board, Inc.	7	TBD	TBD	TBD	$64,891	$320,910	$0	$385,801	Yes
Public Charging	Likely	Aj's Bar & Grill	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	Black and Veatch	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	Yes
Public Charging	Likely	CCMHealth	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	Yes
Public Charging	Likely	City of Centerville	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	City of Hastings	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	Likely	City of Inver Grove Heights	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	City of Zumbrota	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	Energy Integrated Solutions	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	Energy Management Solutions	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	Likely	Energy Management Solutions	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	Likely	Knollwood Mall	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	Yes
Public Charging	Likely	Lexus of Wayzata	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	MG Strip Mall	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	Yes
Public Charging	Likely	OATI	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	Yes
Public Charging	Likely	RE Purvis and Associates	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	Room & Board, Inc.	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Public Charging	Likely	Bloomington Chrysler Jeep	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	No
Fleet	TBD	City of Oakdale	11	TBD	TBD	TBD	$42,894	$241,887	TBD	$284,780	TBD
Fleet	TBD	City of St. Anthony	11	TBD	TBD	TBD	$42,894	$241,887	TBD	$284,780	TBD
Fleet	TBD	Hennepin EMS	11	TBD	TBD	TBD	$42,894	$241,887	TBD	$284,780	TBD
Fleet	TBD	Metropolitan Airports Commission - Minneapolis, MN	11	TBD	TBD	TBD	$42,894	$241,887	TBD	$284,780	TBD
Fleet	TBD	Montevideo Police Department	11	TBD	TBD	TBD	$42,894	$241,887	TBD	$284,780	TBD
Fleet	TBD	SouthWest Transit	14	TBD	TBD	TBD	$69,401	$553,637	TBD	$623,038	TBD
Public Charging	TBD	Allina Health - St. Francis Regional Medical Center	12	TBD	TBD	TBD	$37,112	$390,848	$0	$427,960	TBD
Public Charging	TBD	Allina Health - United Hospital - Regina Campus:	8	TBD	TBD	TBD	$34,916	$282,428	$0	$317,344	TBD
Public Charging	TBD	Big Marine Lake Store	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	C&B Operations	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Circle K/Holiday Stores- Jordan	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores- Mankato	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-Burnsville	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-Hastings	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-Lake Elmo	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-Monticello	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-Plymouth	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	Circle K/Holiday Stores-St Cloud	2	TBD	TBD	TBD	$31,622	$119,797	$0	$151,419	TBD
Public Charging	TBD	City of Center City	2	TBD	TBD	TBD	$1,098	$54,210	$0	$55,308	TBD
Public Charging	TBD	City of Lakeville	4	TBD	TBD	TBD	$32,720	$174,007	$0	$206,727	TBD
Public Charging	TBD	City of Robbinsdale MN	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	City of Shafer	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	City of St. Cloud	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Escom Properties, Inc.	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Feldmann Imports	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Jsho Industries Inc.	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	LAZ Parking	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	LJM AMOCO dba 36 Lyn Refuel Station	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Minnehaha Academy	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Montevideo - CCM Health	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Murray County	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Oasis Convenience Store Inc	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Rosedale Center	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Rosedale Chevrolet	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Securian/CUSHMAN & WAKEFIELD, INC.	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Shattuck-St. Mary?s School	5	TBD	TBD	TBD	$33,269	$201,112	$0	$234,382	TBD
Public Charging	TBD	St. Cloud Surgical Center	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Three Rivers Park District	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Toyota of Mankato	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Trinity Lutheran Church	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Unique Software Corporation	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Unity Church-Unitarian	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Victory Parking, Inc.	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Walz Properties, LLC	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD
Public Charging	TBD	Yarmon Ford	4	TBD	TBD	TBD	$17,458	$141,214	$0	$158,672	TBD

PROTECTED DATA ENDS]

Please note that Appendix H10 is marked as “Not Public.” Certain data is considered to be “not public data” pursuant to Minn. Stat. §13.02, Subd.9, and is “Trade Secret” information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

MN Commercial EV Pilot Application Review and Scoring Process Overview

The Company is proposing a new application review and scoring process that will apply a standardized review framework across the Commercial EV Pilots. The Company sought feedback from stakeholders on a straw proposal including possible evaluation criteria to be used for the framework. Based on stakeholder input, we have refined the framework. The three main scoring categories are (1) Project Scope; (2) Customer and Project Readiness; and (3) Equity and Accessibility. A project application will be evaluated on a satisfactory scale of zero to three for each scoring category.[1] There are 300 total points available for each project to earn during the scoring review, with 45 percent of the points allotted to the Project Scope category, 20 percent to Customer and Project Readiness, and 35 percent to Equity and Accessibility. Applications that score 66 percent of the points or higher will qualify to participate and move on to the design and construction phase of the pilots.[2]

Overall, the Company received positive feedback to implement an application review and scoring framework with a strong focus on equity considerations for the Commercial EV Pilots. Several stakeholders provided feedback on what they viewed as the most pertinent elements of the scoring considerations, namely electrification plans and goals, projects that serve disproportionately impacted or undeserved communities, increased access to electricity as a fuel for all, and total project cost. Stakeholders made the following suggestions, as summarized below:

- Xcel Energy should consider providing greater detail and definition moving forward regarding scoring criteria, metrics, and resources to be used in the application review and scoring proposal.
- Xcel Energy should consider whether a one-size-fits-all evaluation is appropriate given commercial EV charging projects across multi-unit dwellings, fleets, and public charging, can cover a broad range of customer needs, use cases, and characteristics.
- Xcel Energy should consider developing a program advisory group focused on establishing, refining, and progressing towards program equity objectives.
- Xcel Energy should seek out all opportunities to address key barriers to entry and increase EV awareness and adoption more generally, with key focuses including increased customer marketing and advisory efforts.

As noted by stakeholders, we acknowledge certain criteria proposed for the framework may be more pertinent for one project compared to another given the breadth of customer needs, use cases, and characteristics across multi-dwelling unit, fleet, and public charging projects. However, we believe it is important for each approved commercial pilot project application to meet minimum scoring

[1] The evaluation scale to be used for each scoring criteria ranges from zero to three, with zero representing "Not Acceptable," one representing "Below Average," two representing "Satisfactory," and three meaning "Excellent."

[2] In this way, project applications must earn two-thirds of the total available points (nearly 200), and points must be generated in both the Project Scope and Equity and Accessibility categories given their prioritized weighting. Based on commercial EV project applications we have received to date across our operations, we anticipate that applications will score points, to some degree, in all three scoring categories. If applications do not meet the minimum number of points, our Pre-Electrification Consultants and Commercial EV Advisors will advise customers on ways in which a customer can improve their application.

threshold to ensure the Company is upholding goals of enhancing the customer experience and advancing equitable and accessible EV charging opportunities in its commercial EV program portfolio. Within each scoring category, we have incorporated several metrics and criteria to offer a intentional and thorough application evaluation process. The details of each scoring category are provided below.

Project Scope. The Company proposes to consider estimated total project cost in relation to the number of charging ports, as well as the number of chargers, charger power capacity range (in kW), anticipated number of vehicles and utilization, percentage of off-peak and/or managed charging, and estimated transportation emissions reductions. Aligned with stakeholder input, criteria centered on cost considerations, increasing charging access, and emissions reductions carry the most weight in the Project Scope category. In general, projects demonstrating a larger potential impact involving a high quantity of charging ports, vehicles and utilization, and emissions reduction potential will be awarded more points.

Customer and Project Readiness. The Customer and Project Readiness scoring category will evaluate customer electrification goals and site readiness for infrastructure based on proposed in-service dates, documented project timelines and whether the site is undeveloped, under construction, undergoing restoration work, or ready for construction. This category will also consider the certainty of a proposed project securing external funding and overall customer and stakeholder alignment, including community engagement plans. In response to stakeholder feedback, projects that demonstrate the customer's plans and goals for electrification and their overall internal and external stakeholder buy-in will be awarded more points in this scoring category.

Equity and Accessibility. The Equity and Accessibility scoring category will include evaluation of whether the project being considered increases access to electricity as a fuel for all, increases awareness and adoption of EVs, serves disproportionately impacted or underserved customers, including income qualified communities, BIPOC communities, tribal nations, and rural communities, and is affiliated with or promotes small or underutilized businesses. Projects that are aligned with stakeholder interests, demonstrate their ability to increase access to electricity as a fuel for all and serve disproportionately impacted or underserved communities will receive more points. The Company recognizes the importance of equitable access to charging infrastructure and incentives and is committed to ensuring that accepted projects deliver on these priorities. We believe evaluating applications on whether these elements described above are engrained in project goals and implementation will enable the Company to further equity-focused EV adoption and charging infrastructure expansion. By intentionally increasing access, customer options, education, and community engagement, we see great opportunity to enhance the customer experience.

The Company recommends projects be evaluated using the following equity measures:

- giving applicants the opportunity to self-identify and describe when a site will serve income qualified, disproportionately impacted, or underserved communities. Examples may include BIPOC communities, rural areas, and tribal nations. For supporting evidence, the Company will look to state and federal definitions, tools, and programs for qualifying project such as that used by the Minnesota Pollution Control Agency (MPCA)[3] and the White House Council on Environmental Quality (CEQ);[4]

- prioritizing public organizations and those seeking to provide accessible and affordable service for income qualified customers or communities;
- prioritizing projects that incorporate community engagement plans to consult, educate, and/or involve stakeholders and income qualified customers or communities;
- prioritizing projects that support income qualified customers or communities through confirmation of their participation in the Weatherization Assistance Program (WAP), Multifamily Weatherization, Affordable Housing Rebate Programs, or Minnesota's Low-Income Renter Classification within the last 5 years or that they currently meet qualification criteria for those programs;
- prioritizing projects that involve or promote small or underutilized businesses, particularly those that are minority-owned, women-owned, and veteran-owned. For supporting evidence, the Company will look to state definitions, tools, and programs to confirm listing on Minnesota's Unified Certification Program (MNUCP) for Disadvantaged Business Enterprises (DBE),[5] the Metropolitan Council's Underutilized Business Program (MCUB),[6] or that they currently meet the qualification criteria for those programs.

[3] MPCA, Environmental Justice Screening Tool, https://mpca.maps.arcgis.com/apps/MapSeries/index.html?appid=f5bf57c8dac24404b7f8ef1717f57d00
[4] CEQ, Climate and Economic Justice Screening Tool. https://screeningtool.geoplatform.gov/en/#13.88/45.00948/-93.2844
[5] MNUCP information and the DBE directory can be accessed through the following hyperlink: https://mnucp.org/.
[6] MCUB information and the directory can be accessed through the following hyperlink: Metropolitan Council Underutilized Business Program (MCUB) - Metropolitan Council (metrocouncil.org)

XCEL ENERGY MINNESOTA COMMERCIAL EV PILOT APPLICATION REVIEW & SCORING WORKSHEET

Scoring Category and Criteria	Weight	Evaluation Scale *0 = Not Acceptable* *1 = Below Average* *2 = Satisfactory* *3 = Excellent*	Max Score
Project Scope	**45%**		**150**
Total project cost / cost per port	10%	3	30
Number of charging ports	10%	3	30
Number of chargers	5%	3	15
Charger power capacity range (in kW)	5%	3	15
Number of vehicles and utilization	5%	3	15
Percentage of off-peak and/or managed charging	5%	3	15
Transportation emissions reductions	5%	3	15
Customer and Project Readiness	**20%**		**60**
Customer electrification plans and goals	7%	3	21
External funding contributions	3%	3	9
Customer and stakeholder readiness	7%	3	21
Site readiness and project timeline	3%	3	9
Equity and Accessibility	**35%**		**90**
Increases access to electricity as a fuel for all	10%	3	30
Increases awareness and adoption of EVs	10%	3	30
Serves disproportionately impacted / underserved and income-qualified communities	10%	3	30
Affiliated with or promotes small or underutilized businesses	5%	3	15
Total	**100%**		**300**

Electric Vehicles	Transportation Electrification Plan	2024	GOAL

2024 Net Present Cost Benefit Summary Analysis For All Participants Benefits (Positive Values) Costs (Negative Values)

	Participant Test ($Total)	Utility Test ($Total)	Electric Rate Impact Test ($Total)	Societal Test ($Total)	Minnesota Test ($Total)
Electric System Impacts					
TEP Program Costs (CapEx Revenue Requirements)	N/A	(9,915,210)	(9,915,210)	(9,915,210)	(9,915,210)
Generation Capacity	N/A	(6,882,979)	(6,882,979)	(7,496,822)	(7,496,822)
Transmission and Distribution Capacity	N/A	(773,476)	(773,476)	(843,419)	(843,419)
Energy Generation	N/A	(17,991,735)	(17,991,735)	(19,702,777)	(19,702,777)
Market Effects and Ancillary Services	N/A	(512,964)	(512,964)	(560,860)	(560,860)
Subtotal	N/A	(36,076,364)	(36,076,364)	(38,519,088)	(38,519,088)
Environmental Externalities and Non-Energy Impacts					
Electric Environmental Externalities	N/A	N/A	N/A	(3,855,316)	(3,855,316)
Gas Environmental Externalities	N/A	N/A	N/A	0	0
Other Fuels Environmental Externalities	N/A	N/A	N/A	29,683,463	29,683,463
Electric Non-Energy Benefits	N/A	N/A	N/A	0	0
Gas Non-Energy Benefits	N/A	N/A	N/A	0	0
Other Fuels Benefits	222,623,276	N/A	N/A	222,623,276	222,623,276
Utility Performance Incentives	N/A	0	0	0	0
Utility Non-Energy Benefits	N/A	0	0	0	0
Subtotal	222,623,276	0	0	248,451,423	248,451,423
Participant Impacts					
Electric Bill	(70,162,850)	N/A	63,934,664	N/A	N/A
Gas Bill	0	N/A	N/A	N/A	N/A
Participant Rebates and Incentives	0	N/A	N/A	0	N/A
Incremental Capital	(222,683,000)	N/A	N/A	(222,683,000)	N/A
Incremental O&M	83,544,181	N/A	N/A	83,544,181	N/A
Subtotal	(209,301,669)	N/A	63,934,664	(139,138,819)	N/A
Utility Impacts					
Utility Project Costs					
TEP Program Costs (O&M Revenue Requirements)	N/A	3,796,708	3,796,708	3,796,708	3,796,708
Project Administration	N/A	0	0	0	0
Advertising & Promotion	N/A	0	0	0	0
Measurement & Verification	N/A	0	0	0	0
Rebates	N/A	0	0	0	0
Other	N/A	0	0	0	0
Subtotal	N/A	3,796,708	**3,796,708**	3,796,708	3,796,708
Benefits	306,167,457	3,796,708	67,731,372	339,647,628	256,103,447
Costs	(292,845,850)	(26,161,154)	(26,161,154)	(255,142,194)	(32,459,194)
Net Benefit (Cost)	**13,321,607**	**(22,364,446)**	**41,570,218**	**84,505,434**	**223,644,253**
Benefit/Cost Ratio	**1.05**	**0.15**	**2.59**	**1.33**	**7.89**

Note: Dollar values represent present value of impacts accumulated over the lifetime of the measures.

Beneficial Electrification Impacts

Lifetime (Weighted on Generator kWh)	10.0 years
T & D Loss Factor (Energy)	8.70%
T & D Loss Factor (Demand)	10.56%
System Coincident kW Saved at Generator	**-7733.95 kW**
Annual kWh Saved at Customer	-49,800,987 kWh
Annual kWh Saved at Generator	**-54,133,673 kWh**
Annual Gallons of Gasoline Saved	**7,000,479 Gal.**
Annual Gallons of Diesel Saved	**0 Gal.**
Incremental Evs	**13,099**
Incremental EBuss	**0**

First year Carbon Emissions Reductions

Electric Electrification	-16,121 tons CO2
Other Fuel Electrification	68,578 tons CO2
TOTAL	52,457 tons CO2

Lifetime Carbon Emissions Reductions

Electric Electrification	-87,917 tons CO2
Other Fuel Electrification	685,784 tons CO2
TOTAL	597,867 tons CO2

Electric Vehicles	Transportation Electrification Plan	2025	GOAL

2025 Net Present Cost Benefit Summary Analysis For All Participants Benefits (Positive Values) Costs (Negative Values)

	Participant Test ($Total)	Utility Test ($Total)	Electric Rate Impact Test ($Total)	Societal Test ($Total)	Minnesota Test ($Total)
Electric System Impacts					
TEP Program Costs (CapEx Revenue Requirements)	N/A	(16,078,387)	(16,078,387)	(16,078,387)	(16,078,387)
Generation Capacity	N/A	(7,643,378)	(7,643,378)	(8,325,036)	(8,325,036)
Transmission and Distribution Capacity	N/A	(864,920)	(864,920)	(943,132)	(943,132)
Energy Generation	N/A	(20,361,810)	(20,361,810)	(22,232,106)	(22,232,106)
Market Effects and Ancillary Services	N/A	(577,402)	(577,402)	(630,005)	(630,005)
Subtotal	N/A	(45,525,898)	(45,525,898)	(48,208,667)	(48,208,667)
Environmental Externalities and Non-Energy Impacts					
Electric Environmental Externalities	N/A	N/A	N/A	(3,840,019)	(3,840,019)
Gas Environmental Externalities	N/A	N/A	N/A	0	0
Other Fuels Environmental Externalities	N/A	N/A	N/A	33,013,545	33,013,545
Electric Non-Energy Benefits	N/A	N/A	N/A	0	0
Gas Non-Energy Benefits	N/A	N/A	N/A	0	0
Other Fuels Benefits	243,204,755	N/A	N/A	243,204,755	243,204,755
Utility Performance Incentives	N/A	0	0	0	0
Utility Non-Energy Benefits	N/A	0	0	0	0
Subtotal	243,204,755	0	0	272,378,281	272,378,281
Participant Impacts					
Electric Bill	(75,007,300)	N/A	68,353,778	N/A	N/A
Gas Bill	0	N/A	N/A	N/A	N/A
Participant Rebates and Incentives	0	N/A	N/A	0	N/A
Incremental Capital	(243,270,000)	N/A	N/A	(243,270,000)	N/A
Incremental O&M	91,267,824	N/A	N/A	91,267,824	N/A
Subtotal	(227,009,476)	N/A	68,353,778	(152,002,176)	N/A
Utility Impacts					
Utility Project Costs					
TEP Program Costs (O&M Revenue Requirements)	N/A	5,681,557	5,681,557	5,681,557	5,681,557
Project Administration	N/A	0	0	0	0
Advertising & Promotion	N/A	0	0	0	0
Measurement & Verification	N/A	0	0	0	0
Rebates	N/A	0	0	0	0
Other	N/A	0	0	0	0
Subtotal	N/A	5,681,557	**5,681,557**	5,681,557	5,681,557
Benefits	334,472,579	5,681,557	74,035,335	373,167,680	281,899,856
Costs	(318,277,300)	(29,447,510)	(29,447,510)	(279,240,298)	(35,970,298)
Net Benefit (Cost)	**16,195,278**	**(23,765,954)**	**44,587,824**	**93,927,382**	**245,929,558**
Benefit/Cost Ratio	**1.05**	**0.19**	**2.51**	**1.34**	**7.84**

Note: Dollar values represent present value of impacts accumulated over the lifetime of the measures.

Beneficial Electrification Impacts

Lifetime (Weighted on Generator kWh)	10.0 years
T & D Loss Factor (Energy)	8.70%
T & D Loss Factor (Demand)	10.56%
System Coincident kW Saved at Generator	**-8448.95 kW**
Annual kWh Saved at Customer	-54,405,078 kWh
Annual kWh Saved at Generator	**-59,138,320 kWh**
Annual Gallons of Gasoline Saved	**7,647,672 Gal.**
Annual Gallons of Diesel Saved	**0 Gal.**
Incremental Evs	**14,310**
Incremental Ebus	**0**

First year Carbon Emissions Reductions

Electric Electrification	-11,612 tons CO2
Other Fuel Electrification	74,918 tons CO2
TOTAL	63,307 tons CO2

Lifetime Carbon Emissions Reductions

Electric Electrification	-86,392 tons CO2
Other Fuel Electrification	749,185 tons CO2
TOTAL	662,793 tons CO2

Electric Vehicles	Transportation Electrification Plan	2026	GOAL

2026 Net Present Cost Benefit Summary Analysis For All Participants Benefits (Positive Values) Costs (Negative Values)

EBus

	Participant Test ($Total)	Utility Test ($Total)	Electric Rate Impact Test ($Total)	Societal Test ($Total)	Minnesota Test ($Total)
Electric System Impacts					
TEP Program Costs (CapEx Revenue Requirements)	N/A	(3,248,082)	(3,248,082)	(3,248,082)	(3,248,082)
Generation Capacity	N/A	(10,226,817)	(10,226,817)	(11,138,874)	(11,138,874)
Transmission and Distribution Capacity	N/A	(1,165,344)	(1,165,344)	(1,270,722)	(1,270,722)
Energy Generation	N/A	(26,821,479)	(26,821,479)	(29,317,276)	(29,317,276)
Market Effects and Ancillary Services	N/A	(764,273)	(764,273)	(834,537)	(834,537)
Subtotal	N/A	(42,225,994)	(42,225,994)	(45,809,490)	(45,809,490)
Environmental Externalities and Non-Energy Impacts					
Electric Environmental Externalities	N/A	N/A	N/A	(4,981,115)	(4,981,115)
Gas Environmental Externalities	N/A	N/A	N/A	0	0
Other Fuels Environmental Externalities	N/A	N/A	N/A	44,242,093	44,242,093
Electric Non-Energy Benefits	N/A	N/A	N/A	0	0
Gas Non-Energy Benefits	N/A	N/A	N/A	0	0
Other Fuels Benefits	330,909,628	N/A	N/A	330,909,628	330,909,628
Utility Performance Incentives	N/A	0	0	0	0
Utility Non-Energy Benefits	N/A	0	0	0	0
Subtotal	330,909,628	0	0	370,170,606	370,170,606
Participant Impacts					
Electric Bill	(100,251,195)	N/A	91,365,160	N/A	N/A
Gas Bill	0	N/A	N/A	N/A	N/A
Participant Rebates and Incentives	0	N/A	N/A	0	N/A
Incremental Capital	(320,644,000)	N/A	N/A	(320,644,000)	N/A
Incremental O&M	120,206,752	N/A	N/A	120,206,752	N/A
Subtotal	(300,688,443)	N/A	91,365,160	(200,437,248)	N/A
Utility Impacts					
Utility Project Costs					
TEP Program Costs (O&M Revenue Requirements)	N/A	3,574,045	3,574,045	3,574,045	3,574,045
Project Administration	N/A	0	0	0	0
Advertising & Promotion	N/A	0	0	0	0
Measurement & Verification	N/A	0	0	0	0
Rebates	N/A	0	0	0	0
Other	N/A	0	0	0	0
Subtotal	N/A	3,574,045	**3,574,045**	3,574,045	3,574,045
Benefits	451,116,380	3,574,045	94,939,206	498,932,518	378,725,766
Costs	(420,895,195)	(38,977,912)	(38,977,912)	(368,186,523)	(47,542,523)
Net Benefit (Cost)	**30,221,185**	**(35,403,867)**	**55,961,293**	**130,745,995**	**331,183,243**
Benefit/Cost Ratio	**1.07**	**0.09**	**2.44**	**1.36**	**7.97**

Note: Dollar values represent present value of impacts accumulated over the lifetime of the measures.

Beneficial Electrification Impacts	
Lifetime (Weighted on Generator kWh)	10.0 years
T & D Loss Factor (Energy)	8.70%
T & D Loss Factor (Demand)	10.56%
System Coincident kW Saved at Generator	**-11121.17 kW**
Annual kWh Saved at Customer	-71,612,235 kWh
Annual kWh Saved at Generator	**-77,842,500 kWh**
Annual Gallons of Gasoline Saved	**10,064,358 Gal.**
Annual Gallons of Diesel Saved	**5,000 Gal.**
Incremental Evs	**18,832**
Incremental Ebus	**2**

First year Carbon Emissions Reductions	
Electric Electrification	-14,661 tons CO2
Other Fuel Electrification	98,649 tons CO2
TOTAL	83,988 tons CO2

Lifetime Carbon Emissions Reductions	
Electric Electrification	-110,426 tons CO2
Other Fuel Electrification	986,491 tons CO2
TOTAL	876,064 tons CO2

Electric Vehicles	Transportation Electrification Plan	2027	GOAL

2027 Net Present Cost Benefit Summary Analysis For All Participants Benefits (Positive Values) Costs (Negative Values)

EBus

	Participant Test ($Total)	Utility Test ($Total)	Electric Rate Impact Test ($Total)	Societal Test ($Total)	Minnesota Test ($Total)
Electric System Impacts					
TEP Program Costs (CapEx Revenue Requirements)	N/A	(4,484,372)	(4,484,372)	(4,484,372)	(4,484,372)
Generation Capacity	N/A	(13,431,288)	(13,431,288)	(14,629,128)	(14,629,128)
Transmission and Distribution Capacity	N/A	(1,530,493)	(1,530,493)	(1,668,890)	(1,668,890)
Energy Generation	N/A	(35,225,720)	(35,225,720)	(38,503,550)	(38,503,550)
Market Effects and Ancillary Services	N/A	(1,003,750)	(1,003,750)	(1,096,031)	(1,096,031)
Subtotal	N/A	(55,675,623)	(55,675,623)	(60,381,972)	(60,381,972)
Environmental Externalities and Non-Energy Impacts					
Electric Environmental Externalities	N/A	N/A	N/A	(6,541,897)	(6,541,897)
Gas Environmental Externalities	N/A	N/A	N/A	0	0
Other Fuels Environmental Externalities	N/A	N/A	N/A	58,084,028	58,084,028
Electric Non-Energy Benefits	N/A	N/A	N/A	0	0
Gas Non-Energy Benefits	N/A	N/A	N/A	0	0
Other Fuels Benefits	434,421,968	N/A	N/A	434,421,968	434,421,968
Utility Performance Incentives	N/A	0	0	0	0
Utility Non-Energy Benefits	N/A	0	0	0	0
Subtotal	434,421,968	0	0	485,964,099	485,964,099
Participant Impacts					
Electric Bill	(130,439,697)	N/A	118,877,823	N/A	N/A
Gas Bill	0	N/A	N/A	N/A	N/A
Participant Rebates and Incentives	0	N/A	N/A	0	N/A
Incremental Capital	(420,546,000)	N/A	N/A	(420,546,000)	N/A
Incremental O&M	157,776,620	N/A	N/A	157,776,620	N/A
Subtotal	(393,209,078)	N/A	118,877,823	(262,769,380)	N/A
Utility Impacts					
Utility Project Costs					
TEP Program Costs (O&M Revenue Requirements)	N/A	4,496,480	4,496,480	4,496,480	4,496,480
Project Administration	N/A	0	0	0	0
Advertising & Promotion	N/A	0	0	0	0
Measurement & Verification	N/A	0	0	0	0
Rebates	N/A	0	0	0	0
Other	N/A	0	0	0	0
Subtotal	N/A	4,496,480	**4,496,480**	4,496,480	4,496,480
Benefits	592,198,588	4,496,480	123,374,303	654,779,095	497,002,475
Costs	(550,985,697)	(51,191,250)	(51,191,250)	(482,985,496)	(62,439,496)
Net Benefit (Cost)	**41,212,890**	**(46,694,771)**	**72,183,052**	**171,793,599**	**434,562,979**
Benefit/Cost Ratio	**1.07**	**0.09**	**2.41**	**1.36**	**7.96**

Note: Dollar values represent present value of impacts accumulated over the lifetime of the measures.

Beneficial Electrification Impacts

Lifetime (Weighted on Generator kWh)	10.0 years
T & D Loss Factor (Energy)	8.70%
T & D Loss Factor (Demand)	10.56%
System Coincident kW Saved at Generator	**-14605.88 kW**
Annual kWh Saved at Customer	-94,051,211 kWh
Annual kWh Saved at Generator	**-102,233,666 kWh**
Annual Gallons of Gasoline Saved	**13,220,693 Gal.**
Annual Gallons of Diesel Saved	**0 Gal.**
Incremental Evs	**24,738**
Incremental Ebus	**0**

First year Carbon Emissions Reductions

Electric Electrification	-19,255 tons CO2
Other Fuel Electrification	129,513 tons CO2
TOTAL	110,259 tons CO2

Lifetime Carbon Emissions Reductions

Electric Electrification	-145,027 tons CO2
Other Fuel Electrification	1,295,132 tons CO2
TOTAL	1,150,104 tons CO2

Redline

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads. Metering may be installed as a sub-meter behind the customer’s main meter, in which case consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer’s non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, a suitable location for meters and associated equipment used for billing. Installations must conform to the Company’s specifications.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customers that elect the Windsource program in calendar year 2015 for at least three (3) 100 kWh blocks or their entire usage on this schedule may receive a one-time $25 bill credit or gift card of the same value.
~~6.~~7. Company waives CIAC requirements for residential customers under the Standard Installation and Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27. N N N

DEFINITION OF PEAK PERIODS

The on-peak period is defined as those hours between 3:00 p.m. and 8:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The mid- peak period is defined as all hours not defined as on-peak or off-peak periods. The off-peak period is defined as those hours between midnight (12:00 a.m.) and 6:00 a.m. every day. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics. ~~N~~

COMMUNICATION COSTS

The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE

1. Electric Vehicle Home Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an Electric Vehicle Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement with the Company.
~~6.~~7. Company waives CIAC requirements for residential customers under the Standard Installation and Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27. ~~N~~ N N N

AVAILABILITY
Available to residential customers taking service under the Residential Time of Day (Rate Codes A02 and A04) to provide electric vehicle charging equipment to serve electric vehicle loads including battery charging and accessory usage. Customers' energy usage will be billed based on their applicable rate codes. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service. Customers electing Pre-Pay Option service are separately invoiced at the time of installation. Installation-Only Service is available for customers who have purchased a compatible EV charger before the launch date of the Voluntary Electric Vehicle Charger Service. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CONTRACT
Customers must contract for this service through an Electric Vehicle Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement with the Company. The contract period will be as long as the customer wishes to use the equipment

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

COST OF SERVICE
Customer Charge per Month

Bundled (A76)	$12.09
Pre-Pay/Installation Only Option (A77)	$2.30

PRE-PAY/INSTALLATION-ONLY OPTION
The Pre-Pay/Installation Only Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company, or who have purchased a compatible EV charger before the launch date of the Electric Vehicle Home Service. Customers choosing the Installation-Only Service are also responsible for a $240 charge covering the cost of installing and setting up the customer-owned charger for integration with the Company's systems and participation in the program.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Voluntary Electric Vehicle Charger Service shall be serviced through wiring connected to customer's single meter provided for Residential Service.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
4. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
5. Customer must execute an Electric Vehicle Home Service Customer Service Agreement with the Company.
6. Company waives CIAC requirements for residential customers under the Standard Installation and Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27. N N N

DEFINITION OF PEAK PERIODS ~~N~~
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF EXPECTED AVERAGE ELECTRIC VEHICLE KWH USAGE
The expected average electric vehicle kWh usage is defined as the Company's estimated average monthly EV energy consumption across all pilot participants.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Subscription Pilot Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an Electric Vehicle Subscription Pilot Service Agreement with the Company. ~~N~~
~~6.~~7. Company waives CIAC requirements for residential customers under the Standard Installation and Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27. N N N

5.1 STANDARD INSTALLATION (Continued)

A. Service at Secondary and Primary Voltage (Continued)

1. *Service Installation*

a. Residential. Company will extend, on private property, to a Company designated service location, a service lateral a maximum distance of 100 feet. When the necessary extension to a Company designated service location exceeds these limits, the customer will be charged for the additional extension according to the Excess Footage Charge set forth below. Customers requesting a preferred service location will also be charged the Excess Footage Charge for each circuit foot Company extends the installation beyond Company's designated service location. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83. N N

Excess Footage Charge

Services	$7.90 per circuit foot ~~R~~

b. Non-Residential. Company will extend, on private property, to a Company designated service location, a distribution lateral, the total cost of which must not exceed a sum equal to three and one half (3.5) times the customer's anticipated annual revenues, excluding the portion of the revenue representing fuel-cost recovery. When the cost of the necessary extension exceeds this limit, the customer will be charged the difference. Please note that this section does not apply to non-residential customers participating in EV programs under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N N

Excess Footage Charge

Excess single phase primary or secondary extension	$8.00 per circuit foot ~~R~~
Excess three phase primary or secondary extension	$13.90 per circuit foot ~~R~~

(Continued on Sheet No. 6-24)

5.1 STANDARD INSTALLATION (Continued)

A. Service at Secondary and Primary Voltage (Continued)

2. *Winter Construction*. When underground facilities are installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30, or because the customer's property, or the streets leading thereto, are not ready to receive the underground facilities by such date, such work will be subject to a Winter Construction Charge when winter conditions of six inches or more of frost exist, snow removal or plowing is required to install service, or burners must be set at the underground facilities in order to install service for the entire length of the underground service. Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install underground facilities during the winter season. The charges immediately below apply to frost depths of 18" or less. At greater frost depths, the Company may individually determine the job cost. The Company reserves the right to charge for any unusual winter construction expenses. All winter construction charges are non-refundable and are in addition to any normal construction charges. If NSP gas and electric facilities are installed in a joint trench for any portion, the Company will waive the lower of the gas and electric winter construction charges on the joint portion. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N

Winter Construction Charge

Thawing	$600.00 per frost burner ~~R~~
Service, primary or secondary distribution extension	$3.80 per trench foot ~~R~~

3. *Unusual Installation Costs*. The customer is required to pay the excess installation cost incurred by the Company because of:
   a. surface or subsurface conditions that impede the installation of distribution facilities,
   b. delays caused by customer, or
   c. paving of streets, alleys, or other areas prior to the installation of underground facilities.

Such payment, if any, will be determined by the Company based on actual costs. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N

(Continued on Sheet No. 6-25)

5.2 GENERAL EXTENSION (Continued)

Non-refundable payments will be in the amount determined by subtracting from the total estimated installation cost
the product of three and one half (3.5) times the anticipated annual revenue, excluding the portion of the revenue ~~T~~
representing fuel-cost recovery, as set forth in Section 5.1, STANDARD INSTALLATION. Additional refundable
payments may be required where service is extended and where customer occupancy is expected to be delayed. In
such cases, for each additional customer served directly from the original contracted extension within five years from
the date of its completion, the person who made the advance payment will receive proportionate refunds as additional ~~T~~
customers take occupancy. The total of such refunds will in no event exceed the total refundable advance payment.
Refunds will be made only for line extensions on private property to a single customer served directly from the
original contracted facilities. Please note that this section does not apply to residential customers participating in EV N
programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers
under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and
market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these
requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N

5.3 SPECIAL FACILITIES

A. Definitions

For the purposes of Section 5.3 and the City Requested Facilities Surcharge Rider, the following definitions apply:

1. "Distribution Facilities" are defined as all primary and secondary voltage wires, poles, insulators, transformers, fixtures, cables, trenches, ductlines, and other associated accessories and equipment, including substation equipment, rated 35kV class and below, whose express function and purpose is for the distribution of electrical power from the Company's distribution substation directly to residential, commercial, and/or industrial customers. Distribution Facilities exclude all facilities used primarily for the purpose of transferring electricity from a generator to a substation and/or from one substation to another substation. As such, Distribution Facilities serve only customers on the primary and secondary rates of the Company.

2. "Transmission Facilities" are defined as all poles, towers, wires, insulators, transformers, fixtures, cables, and other associated structures, accessories and equipment, including substation equipment, rated 25kV class and above, whose express function and purpose is the transmission of electricity from a generator to a substation or substations, and from one substation to another. ~~T~~
~~T~~

3. "Municipality" is defined as any one of the following entities: a county, a city, a township or other unit of local government.

4. "City" is defined as either a statutory city or a home rule charter city consistent with Minn. Stat. §410.015 and §216B.02, Subd. 9.

(Continued on Sheet No. 6-27.1)

Clean

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads. Metering may be installed as a sub-meter behind the customer’s main meter, in which case consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer’s non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, a suitable location for meters and associated equipment used for billing. Installations must conform to the Company’s specifications.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customers that elect the Windsource program in calendar year 2015 for at least three (3) 100 kWh blocks or their entire usage on this schedule may receive a one-time $25 bill credit or gift card of the same value.
7. Company waives CIAC requirements for residential customers under the Standard Installation and N
Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules N
and Regulations on Tariff Sheets No. 6-23 through 6-27. N

DEFINITION OF PEAK PERIODS

The on-peak period is defined as those hours between 3:00 p.m. and 8:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The mid- peak period is defined as all hours not defined as on-peak or off-peak periods. The off-peak period is defined as those hours between midnight (12:00 a.m.) and 6:00 a.m. every day. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

COMMUNICATION COSTS

The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE

1. Electric Vehicle Home Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an Electric Vehicle Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement with the Company.
7. Company waives CIAC requirements for residential customers under the Standard Installation N
and Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of N
the General Rules and Regulations on Tariff Sheets No. 6-23 through 6-27. N

AVAILABILITY
Available to residential customers taking service under the Residential Time of Day (Rate Codes A02 and A04) to provide electric vehicle charging equipment to serve electric vehicle loads including battery charging and accessory usage. Customers' energy usage will be billed based on their applicable rate codes. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service. Customers electing Pre-Pay Option service are separately invoiced at the time of installation. Installation-Only Service is available for customers who have purchased a compatible EV charger before the launch date of the Voluntary Electric Vehicle Charger Service. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CONTRACT
Customers must contract for this service through an Electric Vehicle Home Service/Voluntary Electric Vehicle Charger Service Customer Service Agreement with the Company. The contract period will be as long as the customer wishes to use the equipment

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

COST OF SERVICE
Customer Charge per Month

Bundled (A76)	$12.09
Pre-Pay/Installation Only Option (A77)	$2.30

PRE-PAY/INSTALLATION-ONLY OPTION
The Pre-Pay/Installation Only Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company, or who have purchased a compatible EV charger before the launch date of the Electric Vehicle Home Service. Customers choosing the Installation-Only Service are also responsible for a $240 charge covering the cost of installing and setting up the customer-owned charger for integration with the Company's systems and participation in the program.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Voluntary Electric Vehicle Charger Service shall be serviced through wiring connected to customer's single meter provided for Residential Service.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
4. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
5. Customer must execute an Electric Vehicle Home Service Customer Service Agreement with the Company.
6. Company waives CIAC requirements for residential customers under the Standard Installation and N
Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules N
and Regulations on Tariff Sheets No. 6-23 through 6-27. N

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF EXPECTED AVERAGE ELECTRIC VEHICLE KWH USAGE
The expected average electric vehicle kWh usage is defined as the Company’s estimated average monthly EV energy consumption across all pilot participants.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Subscription Pilot Service shall be served through wiring connected to customer’s single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer’s non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an Electric Vehicle Subscription Pilot Service Agreement with the Company.
7. Company waives CIAC requirements for residential customers under the Standard Installation and N
Extension Rules under Section 5.1(A)(1)(a), Section 5.1 (A)(2) and (3), and Section 5.2 of the General Rules N
and Regulations on Tariff Sheets No. 6-23 through 6-27. N

5.1 STANDARD INSTALLATION (Continued)

A. Service at Secondary and Primary Voltage (Continued)

1. *Service Installation*

a. Residential. Company will extend, on private property, to a Company designated service location, a service lateral a maximum distance of 100 feet. When the necessary extension to a Company designated service location exceeds these limits, the customer will be charged for the additional extension according to the Excess Footage Charge set forth below. Customers requesting a preferred service location will also be charged the Excess Footage Charge for each circuit foot Company extends the installation beyond Company's designated service location. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83. N N

Excess Footage Charge

Services	$7.90 per circuit foot

b. Non-Residential. Company will extend, on private property, to a Company designated service location, a distribution lateral, the total cost of which must not exceed a sum equal to three and one half (3.5) times the customer's anticipated annual revenues, excluding the portion of the revenue representing fuel-cost recovery. When the cost of the necessary extension exceeds this limit, the customer will be charged the difference. Please note that this section does not apply to non-residential customers participating in EV programs under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N N

Excess Footage Charge

Excess single phase primary or secondary extension	$8.00 per circuit foot
Excess three phase primary or secondary extension	$13.90 per circuit foot

(Continued on Sheet No. 6-24)

5.1 STANDARD INSTALLATION (Continued)

A. Service at Secondary and Primary Voltage (Continued)

2. Winter Construction. When underground facilities are installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30, or because the customer's property, or the streets leading thereto, are not ready to receive the underground facilities by such date, such work will be subject to a Winter Construction Charge when winter conditions of six inches or more of frost exist, snow removal or plowing is required to install service, or burners must be set at the underground facilities in order to install service for the entire length of the underground service. Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install underground facilities during the winter season. The charges immediately below apply to frost depths of 18" or less. At greater frost depths, the Company may individually determine the job cost. The Company reserves the right to charge for any unusual winter construction expenses. All winter construction charges are non-refundable and are in addition to any normal construction charges. If NSP gas and electric facilities are installed in a joint trench for any portion, the Company will waive the lower of the gas and electric winter construction charges on the joint portion. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N N

Winter Construction Charge

Thawing	$600.00 per frost burner
Service, primary or secondary distribution extension	$3.80 per trench foot

3. *Unusual Installation Costs*. The customer is required to pay the excess installation cost incurred by the Company because of:
   a. surface or subsurface conditions that impede the installation of distribution facilities,
   b. delays caused by customer, or
   c. paving of streets, alleys, or other areas prior to the installation of underground facilities.

Such payment, if any, will be determined by the Company based on actual costs. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N N

(Continued on Sheet No. 6-25)

5.2 GENERAL EXTENSION (Continued)

Non-refundable payments will be in the amount determined by subtracting from the total estimated installation cost the product of three and one half (3.5) times the anticipated annual revenue, excluding the portion of the revenue representing fuel-cost recovery, as set forth in Section 5.1, STANDARD INSTALLATION. Additional refundable payments may be required where service is extended and where customer occupancy is expected to be delayed. In such cases, for each additional customer served directly from the original contracted extension within five years from the date of its completion, the person who made the advance payment will receive proportionate refunds as additional customers take occupancy. The total of such refunds will in no event exceed the total refundable advance payment. Refunds will be made only for line extensions on private property to a single customer served directly from the original contracted facilities. Please note that this section does not apply to residential customers participating in EV programs under the following Rate Codes: A08, A76, A77, A80, A81, A82, and A83 and non-residential customers under the following Rate Codes: A87, A88, A89, and A90. This section does not apply to affordable housing sites and market rate site hosts in the first tranche of Rate Codes A91, A92, and A93. The Company waives a portion of these requirements for market-rate site hosts in the second tranche of Rate Codes A91, A92, and A93. N N

5.3 SPECIAL FACILITIES

A. Definitions

For the purposes of Section 5.3 and the City Requested Facilities Surcharge Rider, the following definitions apply:

1. "Distribution Facilities" are defined as all primary and secondary voltage wires, poles, insulators, transformers, fixtures, cables, trenches, ductlines, and other associated accessories and equipment, including substation equipment, rated 35kV class and below, whose express function and purpose is for the distribution of electrical power from the Company's distribution substation directly to residential, commercial, and/or industrial customers. Distribution Facilities exclude all facilities used primarily for the purpose of transferring electricity from a generator to a substation and/or from one substation to another substation. As such, Distribution Facilities serve only customers on the primary and secondary rates of the Company.

2. "Transmission Facilities" are defined as all poles, towers, wires, insulators, transformers, fixtures, cables, and other associated structures, accessories and equipment, including substation equipment, rated 25kV class and above, whose express function and purpose is the transmission of electricity from a generator to a substation or substations, and from one substation to another.

3. "Municipality" is defined as any one of the following entities: a county, a city, a township or other unit of local government.

4. "City" is defined as either a statutory city or a home rule charter city consistent with Minn. Stat. §410.015 and §216B.02, Subd. 9.

(Continued on Sheet No. 6-27.1)

APPENDIX I: DISTRIBUTION SYSTEM UPGRADES

Minn. Stat. § 216B.2425 as amended by the Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F. No. 2310) states:

> *Subd. 9.* ***Integrated distribution plan; contents.***
> *The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023:*
>
> > *(1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems;*
> > *(2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and*
> > *(3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.*

We address each requirement below.

I. FORECAST OF UPGRADES

The new law requires:

> *(1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems;*

Minn. Stat. § 216B.1641 is the Community Solar Garden (CSG) statute, the 2023 update to which substantially modified the CSG program.

Minn. Stat. § 216B.1691, subd. 2h, outlines the new Distributed Solar Energy Standard (DSES), which requires three percent of the Company's total retail electric sales in Minnesota to be generated from qualifying solar energy generating systems by the end of 2030. In brief, to count toward the standard, the solar energy generating system must:

(1) have a capacity of ten megawatts or less;

(2) be connected to the public utility's distribution system;

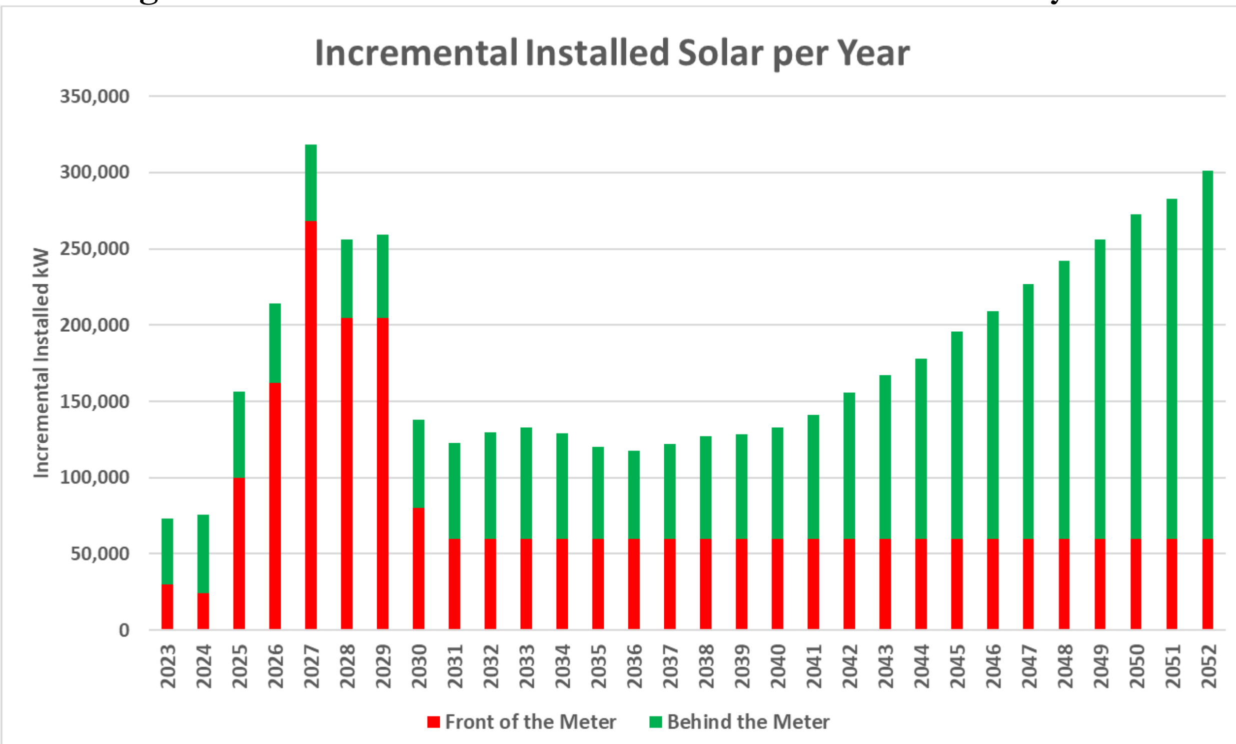
(3) be located in the Minnesota service territory of the public utility; and

(4) be constructed or procured after August 1, 2023.

A. Analysis Methodology

To create the required forecast of distribution system upgrades, we used the location-specific LoadSEER forecast data discussed in *Appendix A1: System Planning*. Specifically, we used the allocation data from the IDP High scenario of the solar PV adoption forecast. The IDP High scenario for solar PV comprises two component forecasts: behind the meter (BTM), and front of the meter (FTM). The BTM forecast component includes rooftop solar, and the FTM component includes both CSG solar and DSES solar. In the "IDP High" scenario, the FTM forecast includes the estimated 500 MW of solar required to meet the DSES spread over 2026-2029, and also assumes that CSG adoption will reach the annual cap specified in Minn. Stat. § 216B.1641. The total amount of solar allocated to the distribution system for both BTM and FTM solar in the 30-year forecast for this analysis is shown in Figure I-1.

Figure I - 1: Forecasted Solar Allocated to the Distribution System



The allocation data represents the results of the Spatial Allocation of the forecasted solar PV adoption in LoadSEER, which produces a forecast, by year and by feeder, of the amount of nameplate solar PV generation that was allocated to specific locations on the distribution system.

The allocation data was then added to the quantity of existing and queued DER for each feeder to determine the resultant total amount of nameplate generation installed on each feeder for each year of the forecast. This total quantity of generation was then compared to the planning limit for the feeder to determine if any violations occurred.

For each year in the forecast, if the amount of DER added to the feeder caused the total amount of DER to exceed the planning limit, then the amount of kW greater than the limit was recorded in that year. The amount of kW that exceeded the planning limit was then multiplied by the marginal cost of distribution capacity to determine the estimated cost to mitigate the violation. A two percent cost escalation rate was also added to account for increasing costs over the forecast period.

The marginal cost of distribution capacity used in this study was $320/kW; this value is the same value used in our most recent Value of Solar filing (Docket No. E002/13-867) and is calculated from historical and forecasted capacity projects in the distribution capital budget. To calculate this value for the Value of Solar, distribution capacity projects completed in the past two years, in-progress in the current year, forecasted for the first two years of the five-year budget are studied. For each project studied, the total cost of the project, including both distribution line and substation costs, is divided by the amount of feeder capacity (in kW) added by the project. These values are then averaged for all projects to determine the average cost to increase the capacity of the distribution system by one kW.

While $320/kW is the distribution marginal capacity cost used for this forecast and is based on historical and near-term planned investments, it is likely not representative of average costs in the long term. As DER penetration continues to increase, many of the forecasted investments will require significant substation expansion or new substations. These more significant investments are typically biased towards higher cost per kW than is represented by the average of investments we make today. Additionally, these costs are not complete as they only represent the distribution portion of the costs; significant levels of incremental DER adoption will likely cause constraints in some parts of the transmission system and will need mitigation.

Given the amount of time between the passing of the new law and this IDP filing, we were not able to identify specific mitigations with specific costs for each feeder with an identified planning limit violation in the forecast. That said, identifying specific mitigations for each feeder would not necessarily improve the accuracy of the upgrade costs; the location-specific forecast in LoadSEER identifies locations with a higher propensity for adoption, but the actual locations in which adoption will occur will be determined by the DER owners/developers. Using the marginal cost of distribution capacity is therefore a reasonable alternative to specific mitigations when applied to a large sample of feeders in need of mitigation. While the estimated costs for any individual limit violation are not likely to be accurate using this method, the total distribution cost to mitigate all violations will be reasonably represented using average costs.

The forecast of upgrades was calculated using two different planning limits as separate scenarios. The first scenario uses the existing Technical Planning Standard (TPS) as the DER planning limit for the feeders. The TPS is defined as 80 percent of the continuous rating plus the daytime minimum load (DML). The second scenario uses an alternative planning limit that we believe is better for the distribution system and for our customers. The alternative planning limit is that the total amount of nameplate FTM generation (i.e., generation not paired with load) must not exceed 50 percent of the continuous rating, and the total nameplate generation including BTM generation must not exceed one hundred percent of the continuous rating. We discuss the benefits and justification for this approach in our November 1, 2023 filing in Docket No. E999/CI-16-521.

B. Summary of Results

The costs that were calculated using the above methodology comprise two components: existing costs and forecasted costs. The existing costs refer to the costs that would be required to bring all of the feeders within the planning limit based on the amount of installed and in-queue generation for each feeder at present. For example, a feeder with a TPS limit of 10 MW, with 12 MW of installed and in queue generation, would incur the existing costs required to raise the TPS to 12 MW. These costs are called "existing" because they are based on known and expected DER adoption and represent costs that would be incurred before any of the forecasted DER adoption is added. However, the quantity of feeders with existing DER capacity constraints is relatively few, and therefore, using the distribution marginal capacity cost to estimate mitigation costs will be less accurate than developing specific mitigations for each feeder. Recent high-level analysis of specific mitigations to address existing capacity constraints, shown in our November 1, 2023 filing in Docket No. E002/M-23-458, has indicated that these costs are estimated at $153 million.

Separately, the forecasted costs are determined based on the impact of the DER forecast allocations from LoadSEER. The forecasted cost analysis assumes that capacity has already been added to mitigate the constraints identified in the "existing costs" component. Throughout the 30-year forecast, a higher quantity of feeders is affected by capacity constraints and so, using the distribution marginal capacity cost to estimate upgrade costs is more likely to produce reasonable cost estimates than using the same methodology for the existing constraints.

The sum of the existing and forecast components of the costs then represents the total costs over the 30-year forecast required to accommodate the forecasted solar. These totals are summarized in Table I-1 below for each planning limit scenario.

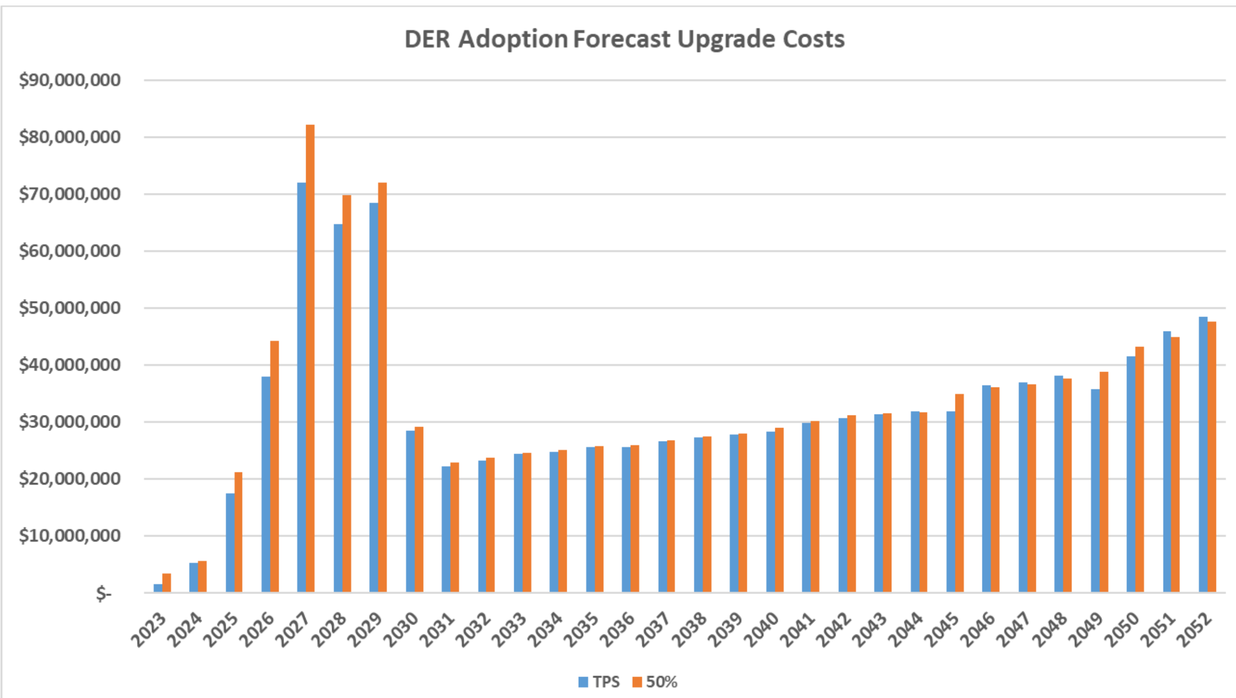
Table I - 1: Summary of Upgrade Cost Components for Each Planning Limit Scenario

Planning Limit Scenario	Existing Constraint Cost	2023-2052 Forecast Cost	Total 30-year Cost
TPS	$47.7M	$992.2M	$1,039.9M
50%	$154.8M	$1,032.9M	$1,187.7M

As shown above, the total 30-year cost for either planning limit scenario is significant, with both exceeding $1 billion. However, there are important differences in the costs for each scenario. The existing costs are substantially larger in the 50% planning limit scenario than in the TPS planning limit scenario. This is due to the fact that the 50 percent planning limit is less accommodating to large front of the meter generation (e.g., CSGs), which currently is the predominant category of distributed generation on our system. Yet the 50 percent planning limit effectively provides capacity for smaller behind the meter generation over the long term.

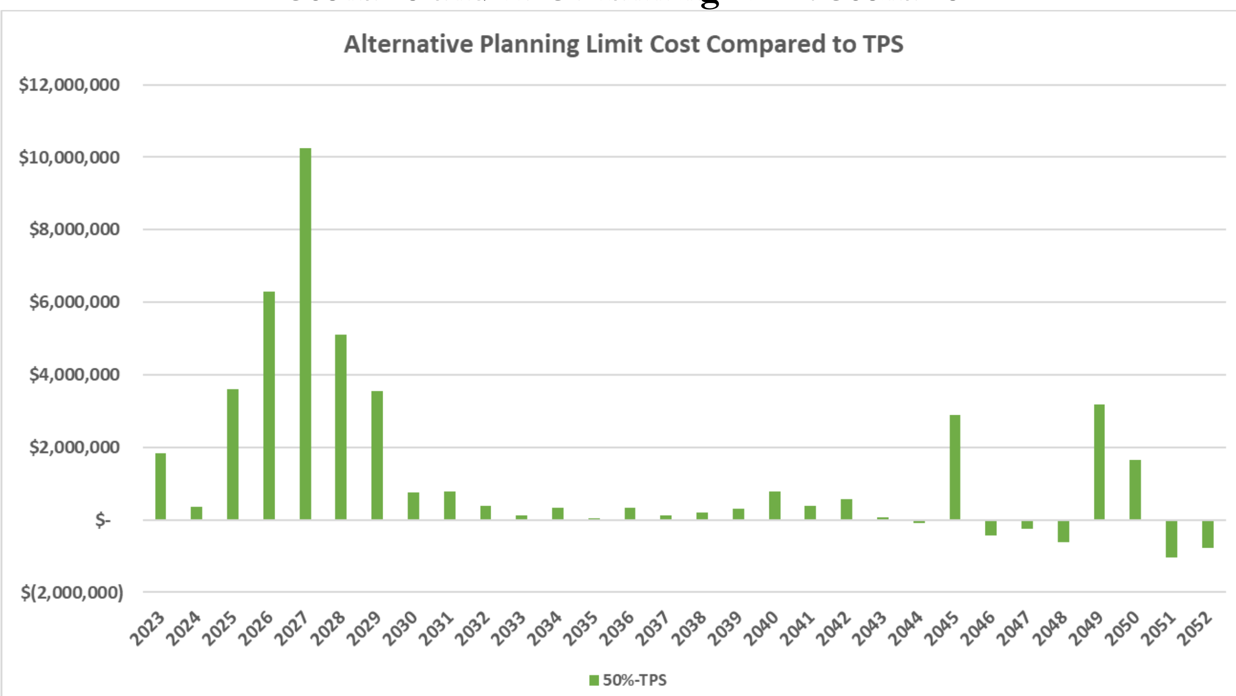
However, the cost difference between the 50 percent planning limit scenario and the TPS planning limit scenario is much narrower in the forecast cost. Investigating the forecast costs in further detail, as shown in Figure I-2, helps demonstrate why this is the case.

Figure I – 2: Forecast of Upgrade Costs 2023-2052, for TPS and 50% Planning Limit Scenarios



The annual costs shown in Figure I-2 demonstrate that the difference in costs between the TPS and 50 percent planning limit scenarios is not consistent throughout the forecast. Particularly, the 50 percent planning limit scenario annual costs are consistently higher than the TPS planning limit scenario costs from the start of the forecast through 2030. Referring back to Figure I-1, it can be seen that this corresponds to a time period in which large, front of the meter generation is the dominant form of DER adoption in the forecast. From 2030 through the early 2040s, when annual behind the meter and front of the meter DER adoption levels are similar, the cost difference between the two planning limit scenarios is minimal. In the mid-2040s the rate of behind the meter DER adoption significantly increases, and during this period, the annual costs in the 50 percent planning limit scenario begin to consistently appear lower than the TPS planning limit scenario. This pattern is reflected in Figure I-3 below, which shows the difference in annual costs between the 50 percent planning limit scenario and the TPS planning limit scenario; positive values reflect periods when the annual costs in the 50% planning limit scenario are greater than those of the TPS planning limit scenario, and negative values reflect when they are less.

Figure I - 3: Annual Upgrade Cost Difference between 50% Planning Limit Scenario and TPS Planning Limit Scenario



During the period in which the cost differential is negative in Figure I-3, the 50 percent planning limit scenario is shown to be more cost-effective than the TPS planning limit. This is due to the fact that the 50 percent planning limit retains capacity for behind the meter DER early on in the forecast so that it can be used at a lower cost to accommodate rising levels of behind the meter DER in the long term. While the total costs shown in Table I-1 indicate a higher cost over 30 years in the 50 percent planning limit scenario, it should be noted that the rate of behind the meter DER adoption is continuing to increase through the end of the 30-year forecast. Therefore, it is expected that the cost differential trend seen after the mid-2040s in

Figure I-3 would continue beyond 2052, bringing the total cost of the 50 percent planning limit scenario closer to or possibly lower than the TPS planning limit scenario in the long term.

II. MEASURES THAT CAN REDUCE THE NEED FOR OR COST OF DISTRIBUTION UPGRADES

The new law requires:

> *(2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs;*

The Company has been studying, evaluating, testing, and piloting many of these new technologies, and is excited about the prospects of improved DER integration. The innovative solutions mentioned in the above-referenced portion of the statute are cutting edge technologies with several benefits and opportunities to reduce system impacts and upgrade costs. Innovative solutions, such as storage programs, power control systems, advanced inverter functions, or a Distributed Energy Resources Management System (DERMS), require more study and evaluation of costs and benefits when compared to a traditional solution. That said, our DER strategy roadmap, discussed in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity*, includes consideration of new tools, technologies, and policies. Below, we address the specific measures listed in Minn. Stat. § 216B.2425 subd. 9(2).

A. Smart Inverters

The Company reserves the right in its operating agreement[1] with large DER installations to require changes to the fixed power factor of the installation. The Company reviews the fixed power factor of all large DER installations in each system impact study and simulates modifications to the fixed power factors of those existing DER installations and the proposed DER installations to mitigate voltage impacts, or in cases of high reverse power flow from DER to mitigate thermal overloads. The Company traditionally performed this review for every DER interconnection system impact study to optimize the fixed power factor of all the DER installations to minimize the reactive power (volt-ampere reactive, VAR) draw from the transmission system.

[1] Found in Attachment 5 of the MN DER Interconnection Agreement.

Volt-Var controls perform much of this same function automatically for voltage impacts based on local voltage conditions. The Company has recently begun studying the use of this advanced inverter functionality in its DER interconnection system impact studies when requested. Considering the Company's unique efforts to optimize the fixed power factors of large DER with every system impact study, the Company believes most of the benefits of increasing hosting capacity by using volt-var curves are already realized. The Company is still excited for the use of volt-var curves to reduce the reactive power draw during non-constrained times and to improve study timelines by reducing or eliminating the need to review fixed power factors of existing DERs.

In the case of Volt-Watt controls, these controls could be enabled in addition to or in place of Volt-Var controls. Instead of absorbing more Vars on a feeder already saturated with Vars, it would decrease power output. This has the added benefit of reducing Var draw from the transmission system. This reduction of power output could mean thermal overloads are less likely to occur, however, the reduction of output is still based on local conditions and the thermal overload constraints could be at other locations on the Company's system. In other words, there is still a risk of an overload if voltages are not as high as expected and are not high enough to dispatch the curtailment through the volt-watt controls. Since the reduced production would have economic impacts for the DER customer, the Company is currently only considering the use of volt-watt curves as an emergency parachute if voltage levels exceed standard thresholds in the field.

B. Grid Management Tools

We understand this requirement to be seeking information on how Advanced Distribution Management System (ADMS) could be utilized to reduce the need for or costs of system upgrades. ADMS has given us the capability to analyze impacts of DER in real-time. This provides the Company personnel enhanced information when using engineering judgement and when evaluating on a case-by-case basis whether it is safe for DER to operate in an alternate configuration that would otherwise require disconnection or system upgrades to operate. ADMS has potential to support hosting capacity in other ways, including through the use of voltage optimization or other automated control functions. The Company continues to gain experience with these tools and test new functionalities in different ways. See *Appendix B1: Grid Modernization* for additional discussion regarding ADMS.

C. DER Management Tools

A DERMS may enhance the integration and utilization of DER to meet the needs of the grid, customers, the market, and regulatory entities. A DERMS would serve to enable the growing interactions between customers and the distribution grid. Our journey to utilize and manage DER will occur over the next decade. A phased implementation approach for DERMS enables the Company to meet policy and regulatory, customer, and business needs. This also balances our investment pacing with the technology launch and performance validation. We are also anticipating FERC Order 2222 to drive new business requirements, new operational dynamics between distribution and transmission, and potential market implications between retail and wholesale markets; to which, we expect DERMS to be a part of the solution to meet FERC Order 2222. A DERMS approach to control DER under a flexible interconnection agreement to reduce the need for or cost of system upgrades could improve DER integration if it is scalable and functions as expected. However, flexible interconnections are a relatively new concept that continues to be defined and evaluated. Given the many unknowns and uncertainty with the implementation of flexible interconnections and the lack of a DERMS within the Company to enable those solutions, the Company cannot commit to when or whether a DERMS can be relied on to provide that function. See Appendix B1 and Appendix E for detailed discussion regarding DERMS and flexible interconnection.

D. Energy Export Tariffs

We understand this requirement to be seeking information on DER compensation methodologies that could reduce the need for distribution system upgrades. Energy export tariffs are part of the Company's Solar*Rewards programs; i.e., those approved programs include compensation for the energy that is exported to the grid. As noted in Appendix E, future interconnection policy could include offerings for limited-export and non-export interconnections, in which customers can choose to adopt energy storage or other technology that can be used to minimize or avoid the reverse power flow to maintain grid reliability and may lead to lower customer interconnection costs. Flexible interconnections, as noted above, are an emerging DER control strategy used to defer or avoid system upgrades necessary for interconnection and increase DER integration. This means that DER may experience temporary curtailment of generation during times of grid constraint, but full generation during times without grid constraint, in exchange for shorter interconnection time or lower customer interconnection costs. Flexible interconnection may become an interconnection offering and would require separate tariffs. We intend to evaluate these approaches further, as noted in Appendix E.

In conclusion, reducing the need for system upgrades will ultimately require a number of varying and complementary approaches, and we expect activities will be spread out over the long term.

III. ALTERNATIVE COST ALLOCATION METHODS

The new law requires:

> *(3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation [DG] owners or developers and ratepayers.*

A tenet of utility ratemaking is cost-causation: that is, costs are allocated to the cost-causer. In the case of distribution system upgrades required to interconnect new generation or load, in Minnesota, those costs are currently paid by the cost-causer, consistent with basic cost causation principles.

For the Company's CSG program, developers are responsible for paying for costs of required upgrades.

In Commission-approved competitive resource acquisition processes, such as those that we would undertake to procure distributed solar projects in compliance with the DSES,[2] bidders include known or anticipated interconnection costs in their bid price, and the project developer is directly responsible for paying those costs. All customers benefit from these system resources; however, in this way, through the normal course of ratemaking, customers ultimately pay for system upgrade costs that are encompassed within the overall contracted cost of a system resource. We note this principle is the same whether a generation project is connected at the transmission or distribution level and helps ensure developers select project locations where it is more efficient to connect. As part of our due diligence process in recent resource acquisitions, we have evaluated interconnection risks (including costs), and overall project pricing has been a heavily weighted factor in the evaluation process as ultimately, the costs of any selected project are passed to customers. We expect to use similar evaluation criteria in future RFPs, which would follow Commission-approved processes and requirements.

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[2] We note that the Commission has opened a new docket regarding implementation of the DSES; *see* Docket No. E002,E015,E017/CI-23-403. Competitive acquisition processes, among other topics, will be discussed as part of the current Comment Period.

Other cost allocation methods have emerged within the industry, and some of these methods may be appropriate for Xcel Energy and Minnesota. We discuss some of these alternatives below and note potential benefits and challenges associated with each.

We are open to parties' feedback on these alternative allocation methods and, ultimately, the Commission's direction on how best to support increased distributed generation while keeping customer bills low and allowing the Company to recover its prudently incurred costs. These alternatives may require additional costs beyond system upgrades, such as technology enhancements and human capital. Further, we note that each alternative discussed below may require changes to the Minnesota Distributed Energy Resources Interconnection Process (MNDIP), MN Distributed Energy Resources Interconnection Agreement (MNDIA), and/or the Company's tariffs. Should the Commission wish to explore alternative cost allocation approaches in more detail, further analysis and record development would be required.

A. Retroactive Cost Sharing Between DG Facilities

Under this method, triggering projects (i.e., the first interconnection applicant) would be required to pay for the costs of interconnection, but the utility would provide them with "true-up" payments collected from subsequently interconnected facilities taking advantage of the capacity created by the upgrades their facility triggered. At our IDP stakeholder workshop on June 12, 2023, which was shortly after this and many other new IDP filing requirements were passed, we asked stakeholders if they had ideas for alternative methods to allocate costs of distribution system upgrades. We received one comment suggesting this approach.

This approach would not shift costs to customers; however, it could lead to higher costs or carrying costs for the first DG owner because there would be no guarantee whether or when subsequent projects would seek to interconnect and thus, share in the cost. Administratively, this approach would be burdensome and costly to manage because it would require new application, tracking, and billing functionalities – and the associated human resources – which would further increase costs to all applicants.

B. Prospective, Location-Specific Cost Sharing Between DG Facilities ("Cost Sharing 2.0")

In this method, also known as "Cost Sharing 2.0," utilities would determine the costs of making a system upgrade and calculate a per-kW cost for the upgrades, which would be assessed to each DG facility interconnecting to that portion of the system based upon the facility's nameplate capacity. The portions of the system targeted for upgrades may be identified either by the utility's analysis of future expansion needs or pending requests for interconnection. This approach could provide more certainty to DG owners and developers that costs would be shared; however, this approach would likely be very administratively burdensome and costly – costs that would need to be included in the per-kW upgrade costs.

We note that the Commission has approved a form of prospective cost sharing for small solar projects. The program, funded an extra fee assessed to interconnection applications for most solar projects up to 40 kW, provides up to $15,000 to eligible projects to cover certain interconnection-related costs.[3]

C. Costs of Interconnection Paid by the Utility and Recovered from All Customers

This approach would expand the portion of interconnection costs recovered in the utility's rate base to include all upgrades on the utility side of the point of interconnection (i.e., for a small generator interconnecting at the customer meter, all upgrade costs would be rate based). Some argue that broader public policy benefits of DG mean that all customers should bear the cost of interconnection to the point of common coupling.

A certain amount of utility-initiated proactive hosting capacity upgrades may be appropriate. The $10 million Distributed Energy Resources System Upgrade Plan approved by the Minnesota state legislature in 2023 is funded through the Renewable Development Account and is one example of customer-funded system upgrades.[4] In addition, we have preliminarily included some such proactive upgrades in our five-year budget presented in *Appendix D: Distribution Financial Information*.

D. Network Upgrade/System Enhancement Credits

In this approach, when studying a new interconnection, utility customers and facilities in that area would also be analyzed for needed upgrades. If network upgrades are found to be a common benefit for the interconnecting facility and surrounding utility customers and facilities, costs can be shared between surrounding facilities and the

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[3] Order Approving Implementation of Cost Sharing Plan as Modified (Docket No. E002/M-18-714), December 19, 2022.
[4] See Minn. Stat. § 216C.378 as added by Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F. No. 2310), Article 12, Section 38.

interconnecting project. This approach is a hybrid wherein the utility analyzes the potential broader benefits of network upgrades and costs are shared if benefits are identified. This may reduce developers' costs and motivate developers to site projects most efficiently. However, this approach would take time to develop, as would the needed tools and supporting human resources, and customers and developers may not agree on common benefits so that would also need further development and discussions.

CONCLUSION

In recent years, various ideas have emerged seeking to find new ways to approach allocation and recovery of costs for distribution system upgrades to accommodate DER interconnection. The Commission has already approved one cost-sharing mechanism. Should the Commission desire to explore other cost allocation approaches, we respectfully suggest that further record development and analysis to evaluate costs, benefits, and other policy implications of various options be required.

APPENDIX J: DISTRIBUTED INTELLIGENCE

Order Point 33 of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630 states in part:

> *[D]irect Xcel to refile its [Distributed Intelligence program] proposal in its next IDP consistent with the Company's Colorado settlement.*

Order Point 17 of the Commission's June 28, 2023 Order in Docket No. E002/M-21-814 states:

> *Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing:*
>
> *a. HAN, AMI and AMI-DI specifications and related customer data access policies.*
> *b. Bring-your-own device HAN requirements and terms.*
> *c. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN.*
> *d. Methods to provide customers equal access to the level of data available to the utility.*
> *e. A summary of industry customer data access standards.*

In this Appendix, we provide an overview of Distributed Intelligence (DI) and an update on our planned use cases and releases. We then discuss data access for the Home Area Network (HAN), AMI, and DI, and potential terms and conditions, for which we intend to seek Commission approval in a forthcoming filing. Finally, we discuss the specific terms of the unanimous Settlement Agreement (hereafter "the Colorado DI Settlement" or "the Settlement"), which is referenced in the Commission's Order, and how the terms of the Settlement affect our DI plans in Minnesota.

I. OVERVIEW

The Company is committed to providing affordable, reliable energy solutions that actively promote a clean environment for our communities. At the state level, the Minnesota legislation recently set 2040 as the state's target for 100 percent carbon-free electricity while maintaining customer affordability and reliability. With this commitment in mind, we are making investments in our distribution system that enable us to advance our clean energy transition while continuing to meet and exceed our customers' needs.

To achieve our carbon reduction goals, we will need to work with our customers to continue to grow our Energy Conservation and Optimization (ECO) portfolio – a key component to the clean energy transition. Investments in new technologies, like DI, will enable the company to create new and innovated customer offerings while increasing engagement in existing energy efficiency and demand response ECO programs.

Major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now often equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. This is true for the AMI meters we are deploying, the Itron Riva 4.2, which include DI – a powerful distributed processing capability. When integrated into the Company's broader ecosystem of customer and grid management systems, DI will unlock both customer and grid-facing benefits.

DI refers to the distribution of computing power, analytics, decisions, and action away from a central point to the "edge" of the distribution grid. DI distributes these utility functions closer to localized devices or platforms, such as AMI meters or other "smart" devices on the distribution grid.

The analytics made possible through DI can provide additional insights to help customers make more informed decisions about their energy usage, increase the ability to connect customers to demand-side management programs, and increase the efficacy of time-differentiated rates. In addition, DI allows the Company to create new, innovative demand side management and demand response offerings, an essential component of the clean energy transition.

The Company's selection of DI-capable advanced meters has ensured that metering infrastructure can easily transform through time without having to replace metering technology as standards evolve. DI creates a platform for integration of changes in technology over time which was a functionality that previously did not exist with earlier generations of AMI.

Deployment of DI capabilities is consistent with the Company's strategic objectives to lead the clean energy transition, enhance the customer experience, and keep bills low as DI capabilities further enhance:

- The benefits to distribution operations that our grid modernization investments provide by increasing the level of grid intelligence that can be achieved; and
- The customer experience by providing customers more detailed, informative, and activating insights regarding their energy usage.

As we plan for the grid of the future – we are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution planning, engineering, and operations remain sound. As we continue to implement traditional investments and solutions, which will continue, the Company has begun to build foundational solutions that provide the greatest near-term value to grid operations and customers and plans to develop basic functionality and focus on enhancing the safe, secure, and reliable operation of the grid.

We are not seeking Commission approval of our DI plans at this time; we have taken Commission and stakeholder feedback on our DI strategy and are consistently evaluating technology, programs, status of the commercial marketplace, customer preferences, and costs to determine the most beneficial and cost-effective programs and tools to bring to our customers. That said, as we discuss in Section II below, we are moving forward with certain DI use cases to benefit our Minnesota customers. We intend to seek cost recovery in a future cost recovery proceeding. In addition, we intend to make a separate filing seeking approval of, among other things, new and/or updated tariff sheet(s) in our Electric Rate Book for customer terms and conditions related to initial DI products and services. In the meantime, as we take an enterprise-wide approach to our DI plans, Minnesota customers will be able to access and benefit from new apps and tools as they become available.

II. DISTRIBUTED INTELLIGENCE USE CASES AND RELEASE PLAN

The Company has developed foundational capabilities that focus on enhancing the safe, secure, and reliable operation of the grid and providing AMI-enabled energy insights to customers. Solution categories for initial development include DI Services Platform, Grid-Facing, and Customer-Facing.

The solutions developed to date will benefit all jurisdictions that the Company operates in, including Minnesota.

In the following sections, we provide an overview of the assets developed to date and plans for the future.

A. Distributed Intelligence Solution Categories

1. Distributed Intelligence Services Platform

The DI Services provides a software foundation to support many operational processes for delivering initial and future grid- and customer-facing DI solutions. The DI Services Platform includes interfaces, database, shared services, reference architectures, and metrics needed for reporting. Shared services can be used across multiple DI agent implementations and cover standardized methods for enrollment/eligibility, unenrollment, program creation, DI agent installation, and licensing. Additionally, the Platform includes the Home Area Network (HAN) connectivity capability, which provides Wi-Fi communications between the AMI meter and Wi-Fi enabled devices behind the meter in the customer's home, as well as the Gateway Software Development Kit (SDK) for developers, Bring Your Own Device (BYOD), and Xcel Energy Launchpad functionalities required per the Colorado DI Settlement as described below. These applications enable customers to connect customer authorized third-party devices (e.g., smart thermostats) and read data from the meter via the HAN.

The DI Services Platform will benefit all the Company's customers with AMI meters, regardless of geographic region.

2. Grid-Facing Use Cases

The grid-facing use cases prioritized for initial release focus on safety and protection and increasing grid operational efficiencies. Specific initial grid-facing use cases include:

- <u>High Impedance Detection</u>: Allows the Company to identify "hot spots" on the low voltage distribution (secondary equipment) network. "Hot spots" can result in low/unstable voltage, flickers, interruptions, connection issues, and fires. This project will improve electric service by proactively detecting deteriorating or loose connections on meters and dispatching field crews to locate and address issues.

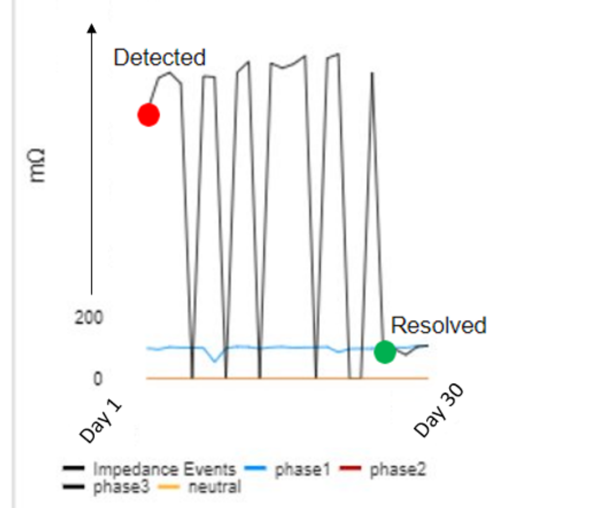
  The Company currently has High Impedance Detection deployed on approximately 5,000 meters in Minnesota, of which there have been five meters that have reported high impedance. Below is a summary of the first high impedance event that was resolved by the Company.

A high impedance event was detected by the AMI meter at a specific customer location. Field crews were then dispatched to the customer's home. The field crews spoke with the customer and the customer reported they had been experiencing flickering lights and issues with their air conditioning unit for some time. The customer's home was also in an area with dense vegetation. Damage was located on the service line approximately 60 feet from the home likely from the vegetation in the area (Figure J-1). The line was repaired, and the Company confirmed through the AMI and DI data that the issue was resolved, and the customer has not experienced the same power quality issues. Figure J-2 provides an example of a high impedance detection app.

This example provides an excellent illustration of the potential benefits of High Impedance detection that include the ability to resolve power quality issues without customer reporting issues, avoiding outages, and reducing costs by dispatching crews in non-emergency situations.

Figure J-1: Vegetation Causing Power Quality Issues Detected by DI

Figure J-2: High Impedance Detection App Illustration



Note : A value above 200mΩ indicates a probable issue. 1mΩ value indicates that there is likely not enough change in electrical behavior to trigger a reading.

- Location Awareness: Provides the electrical location of every meter on the distribution grid, including transformer, phase, and feeder. This information will be used to validate GIS connectivity, improve outage response, feeder phase balancing, and multiple other grid applications. Figure J-3 shows an example of the functionality showing validation of mapping customer meters to their serving transformer.

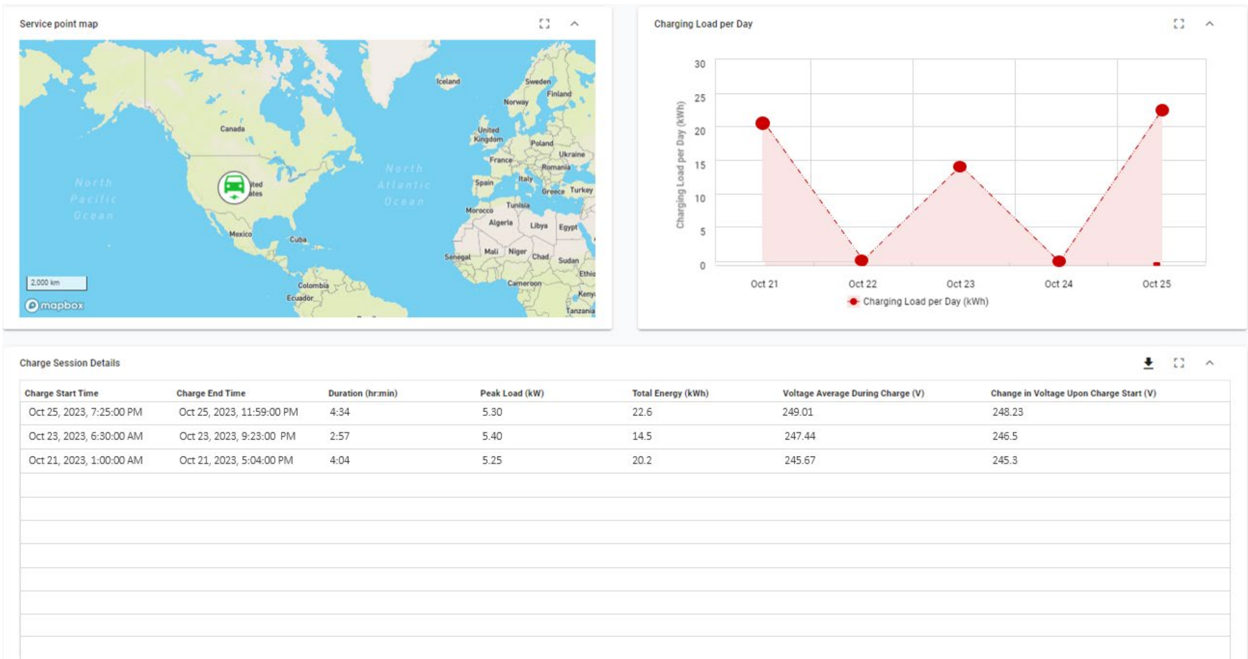
Figure J-3: Locational Awareness Functionality Example

The Company is in the final stages of testing the AMI meter firmware version that enables power line communication that is necessary to enable this use case. After this is complete, the Company will be starting the limited deployment in Minnesota to approximately 1,000 meters.

- EV Detection: Provides the Company with insights into where EVs are located and charging patterns of customers. This information can be leveraged to support system planning, load balancing, and infrastructure upgrade efforts based on awareness of EVs being added to a customer's load profile. This grid-facing use case will also enable the Company to become aware and proactively respond to possible service quality issues and encourage customers to participate in managed charging programs.

  Itron delivered the EV Detection application to the Company on September 28, 2023. The Company is currently in the progress of completing meter testing and will be starting the limited deployment in Minnesota to approximately 1,000 meters. Figure J-4 shows an example of a theoretical customer charging pattern shown in the application. This data that can be leveraged to support system planning, load balancing, etc.

Figure J-4: Example of Customer Charging Pattern Shown on EV Detection DI App



3. Customer-Facing Use Cases

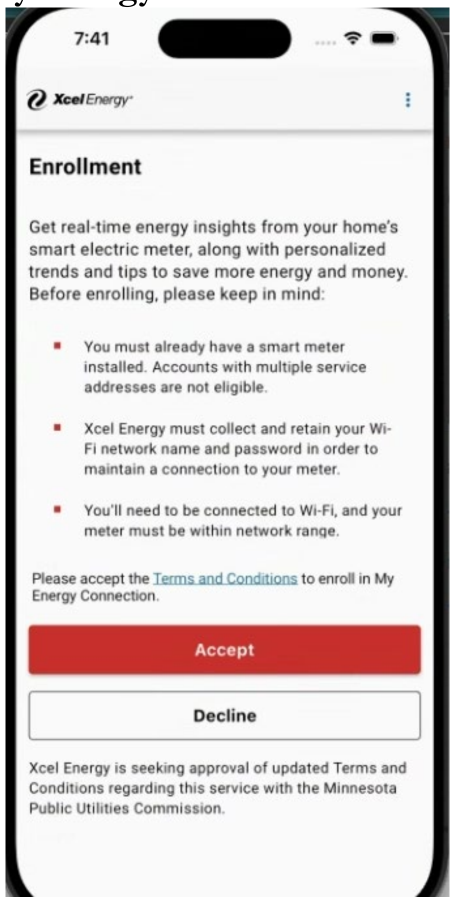
Customer-facing use cases and products are prioritized based on customer preferences, technical capabilities, costs, and benefits. The Company plans on taking an enterprise-wide approach to deploying DI customer-facing use cases unless a use case is prohibited in a jurisdiction.

The Company is in the process of releasing a mobile application called My Energy Connection that provides customers with detailed information on their energy usage. The first release of this mobile application provides users with real-time meter data, energy usage, and rate information starting with the ability to access this information from home via the DI enabled HAN. These capabilities will empower users to shift energy consumption behaviors and expand the depth and breadth of customer engagement across products and services. The initial release will be available to all eligible Xcel Energy customers with single phase AMI meter forms, regardless of geographic region.

Key features included in the **My Energy Connection Release 1** include:

- <u>Onboarding journey enrollment:</u> A step-by-step guide instructing customers how to connect their meter to their Wi-Fi network and the mobile application.[1] As noted above, we will seek Commission approval of terms and conditions in a forthcoming filing. Figure J-5 shows the enrollment screen in My Energy Connection Release 1.

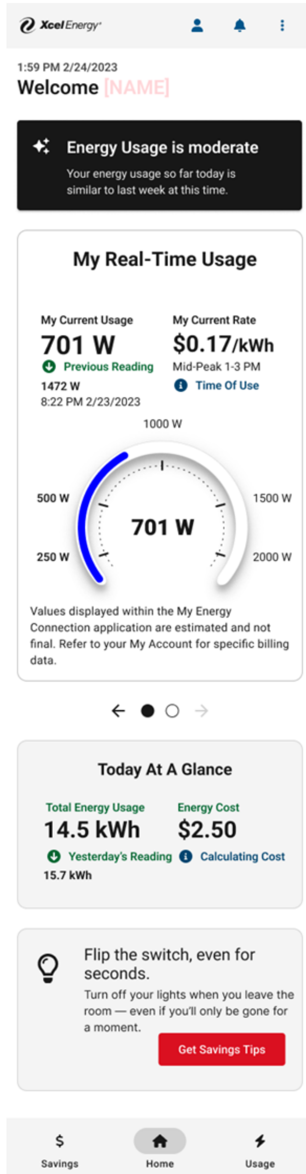
Figure J-5: My Energy Connection Enrollment Screen



- <u>Real-time in-home energy usage presentment (Figure J-6)</u>: A speedometer view and running graph view of a customer's usage in the home that changes in real-time. Includes a reading of the current demand (Watt) and rate as well.

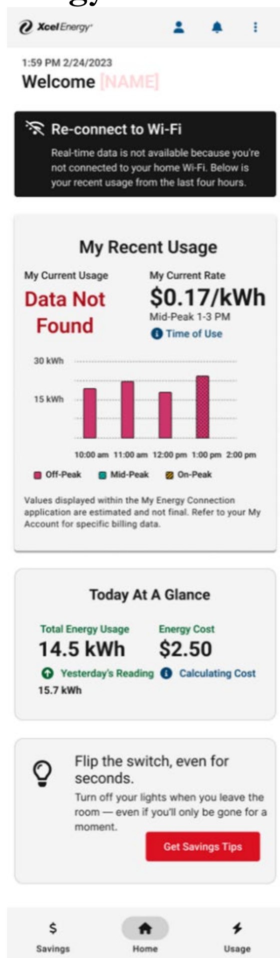
[1] See the enrollment PDF guide at https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/23-06-619%20My%20Energy%20Connection%20Enrollment%20Guide_P1%20(1).pdf.

Figure J-6: Real-Time In-Home Energy Usage Presentment in My Energy Connection



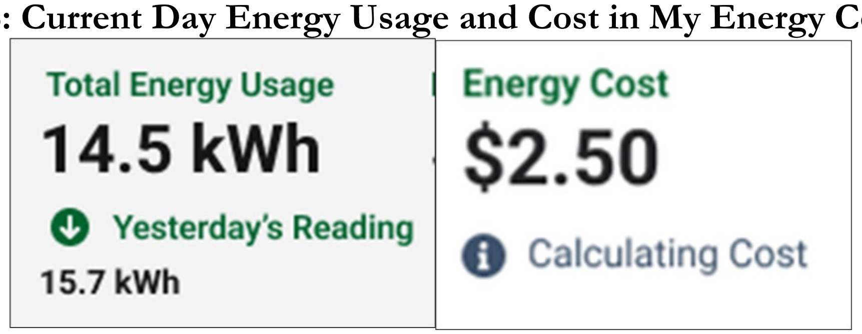
- Away from home 15-minute data (Figure J-7): Energy and rate information updated every 15-minutes while outside of the home.

Figure J-7: 15-Minute Away from Home Energy Usage Presentment in My Energy Connection



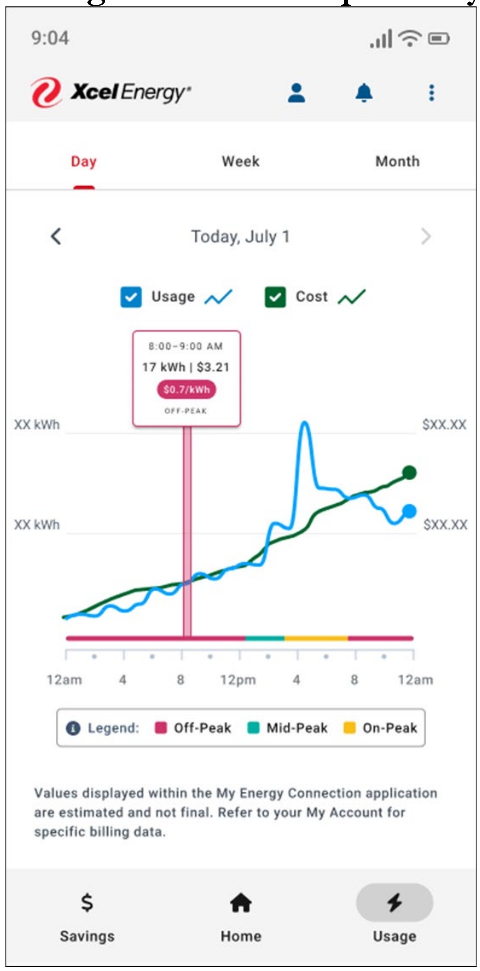
- Running total energy and cost usage for current day (Figure J-8): From midnight to when the customer opens the app, how much energy they've used and how much that usage costs. Total energy usage can be compared to yesterday's usage at that same time.

Figure J-8: Current Day Energy Usage and Cost in My Energy Connection



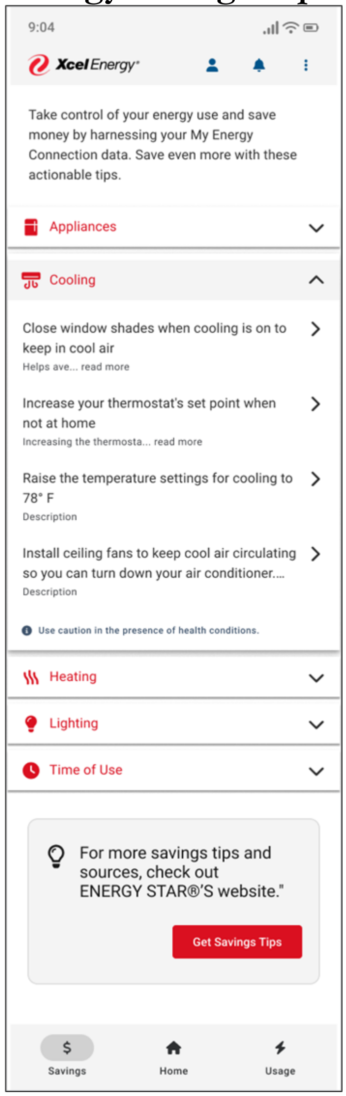
- Historical usage and cost graphs (Figure J-9): A line graph showing the current and historical usage and cost with daily, weekly, and monthly views. Ability to compare to yesterday, last week, and last month.

Figure J-9: Historical Usage and Cost Graph in My Energy Connection



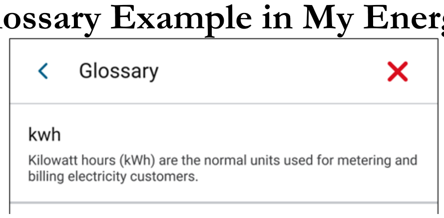
- Actionable savings tips (Figure J-10): Whole home energy savings tips.

Figure J-10: Whole Home Energy Savings Tips in My Energy Connection



- Educational energy items in-app (Figure J-11): Pop-out info icons within the application explaining what certain data points mean along with a glossary for energy terminology used in the app and beyond.

Figure J-11: Glossary Example in My Energy Connection



The second release of My Energy Connection will focus on providing customers with appliance-specific usage and cost breakdowns, also known as disaggregation insights. Customers will be able to access this information through the same mobile application as Release 1 as well as a customer facing website.

Having detailed usage and cost by appliance will allow customers to understand where and when they are using the most energy and will provide focus for their energy savings goals. It will also allow the Company to recommend ECO programs based on the end uses detected in the home. Access to disaggregated versus whole home insights has also been shown to increase the impact of behavioral demand response programs.[2]

My Energy Connection Release 2 will be available both via a mobile application and is anticipated to include:

- Energy usage by appliance: Displays energy consumption and cost refreshed daily for home's identifiable appliances and devices.
- Anomaly alerts: Displays an alert and sends a notification when an appliance's consumption is unusually high compared to previous values.
- Program Recommendations: Analyzes disaggregation data and provides recommendations to customers on programs from which they may benefit.

Future customer-facing products will build on these initial solutions while further taking advantage of the meters' DI capabilities to provide deeper insights into how and when customers use energy as well as personalized alerts and tips. DI on the meter as well as analytics off-meter allow customers to see energy usage by major devices, and understand usage and spend on a real-time, minute, hourly, daily, weekly, or monthly basis. In the future, these insights could be combined with time of use pricing structures and other Company programs to provide customers better opportunities to optimize their spend and/or carbon profile.

Features will be prioritized based on customer feedback and forecasted benefits and may include the following. Currently, we have no specific plans or timelines for these features in Minnesota.

- Time of Use (TOU) Highlights: This feature is only available to customers in Colorado today because of the Company's default residential TOU rate. This feature could be deployed to other states as TOU rates are approved.

[2] DTE Audit and Weatherization Program 2020 Evaluation Report. 2021. MPSC Case No. U-20871.

- Projections and Comparisons: Customers see how their present usage will forecast for their monthly bill and also receive comparisons to previous months or similar homes.
- Savings Visualization: Customers monitor the effect of efficient appliance upgrades or behavioral changes.
- Next Best Action: Customers receive personalized program, rate, or behavioral suggestions customized to their energy usage and appliance ownership.
- Advanced Rate Support: Customers are offered the best rate given their energy usage and appliance ownership.
- Customer Home Offerings: Connects customers with solutions for appliance repairs or upgrades.
- Automation and Control: Allows customers to participate in automated routines that allow them to shift loads.

For Commercial and Industrial (C&I) customers, the Company plans to develop products that work with polyphase meters, a common meter for C&I customers. Polyphase meters measure electricity consumption in multiple phases; they are typically used in industrial and commercial settings where large amounts of electricity are consumed.

The Company is considering launching a Rate Advisor tool in the next two to five years that estimates the customer's bill based on past usage and under different scenarios. For example, the tool would calculate the bill if the customer switched to a different rate (for which they are eligible), enrolls in a new program, or makes behavioral changes such as load shifting.

B. Iterative Design Approach

Customer feedback has informed our DI roadmap and products. In our efforts to better understand customer preferences in the DI space, we have asked customers to answer questions about DI concepts to help inform our digital strategy. The main takeaways are summarized in *Appendix B1: Grid Modernization*.

In a more targeted format, the Company has done extensive research while planning and building the My Energy Connection application. Several customer research strategies were used including card sorting, tree testing, and usability testing.

Card sorting was used to understand customer's preferences around naming conventions and categorization. Results were used to determine the labels, naming conventions, and category groupings that should be used in the application.

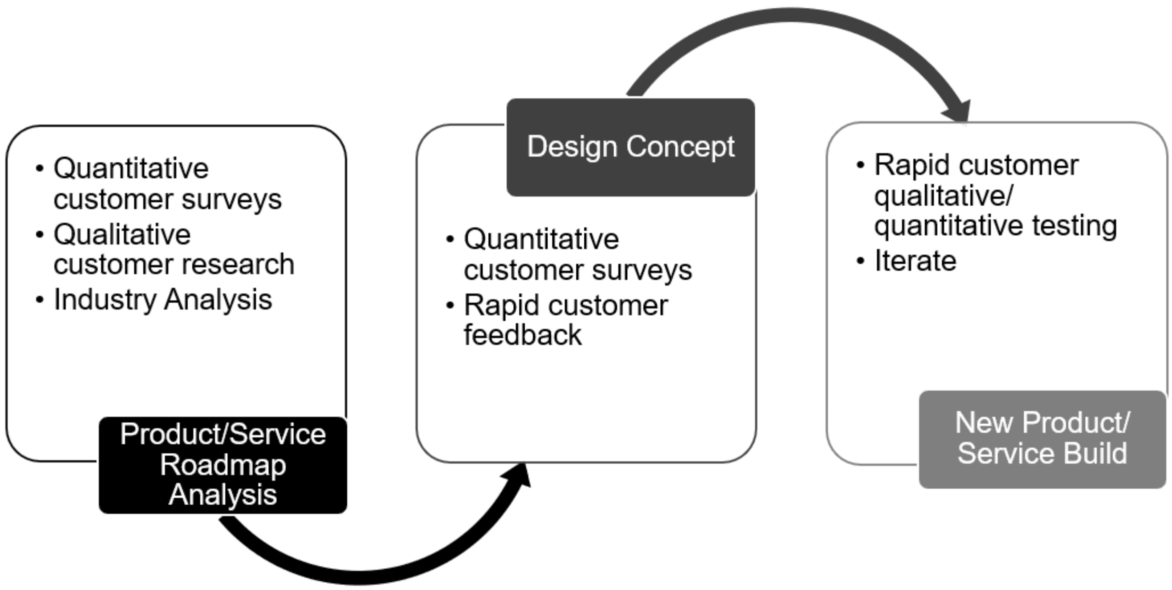
Tree testing was used to understand where items should be located within the application. Customers provided first-level, second-level, and third-level items representing the different items that will be included in the application. Participants were asked if any of the items were difficult to find. The responses were used to reorganize features in the application.

Usability testing was used to improve application architecture by providing customers with a hands-on testing opportunity that they could then provide feedback on. Participants were asked to perform pre-determined tasks within the prototype.

We have tested alpha and beta versions of the My Energy Connection application, surveyed participants, and enhanced the experience in response. We conducted the first Alpha Test with eligible Xcel Energy employees July to November 2021. Improvements were made to application based on the feedback provided. A second Alpha Test was conducted with eligible Xcel Energy employees in July 2022. The Company then conducted a limited deployment with eligible Xcel Energy customers in February 2023. All test deployments were combined with a survey where participants provided feedback on the application. User feedback was used to inform the design of Release 1, planned for late 2023.

The Company plans to use an iterative approach to improve and expand on the customer-facing use cases and products, as shown in Figure J-12. The Company will continually request feedback from customers even after the application and future DI products are deployed. Future products, use cases, and features will be prioritized based on customer feedback and forecasted benefits.

Figure J-12: Iterative Design Strategy Informed by Voice of Customer



For the first release of My Energy Connection, we will be surveying active users of the application to better understand their experience and identify outcomes customers want. In future releases, we plan to capture feedback from users within the application itself on specific interactions. In addition, we will conduct a detailed analysis of the product's performance and users' behavior. We will collect qualitative data through discussions with customers. We will also run customer satisfaction surveys to provide statistical data which will be used to further refine the product.

With each release, our goal will be to respond to customer feedback, improve the customer experience, and incorporate features that increase demand-side management impact. We will use an approach familiar to customers who use web and mobile digital applications – continually providing customers an opportunity to provide feedback on the experience, prioritize future modifications and features based on that feedback, and rapidly respond to customer preferences by continually releasing new versions.

The data referenced above is available to customers via My Account and is consistent with the terms of the Colorado DI Settlement, discussed below.

C. Cost Recovery

The Company plans to seek recovery of capital costs to develop the DI Services Platform, grid-facing use cases, and customer-facing products in future cost recovery proceedings.

The recovery mechanism for operations, maintenance, marketing, customer insights research, and other non-capital costs will likely vary based on the nature of the specific DI application. Products that help customers reduce or shift loads will be proposed for inclusion as part of the Company's Energy Optimization and Conservation (ECO) portfolio. The Company anticipates the My Energy Connection mobile application will help customers reduce overall electric usage and the application will increase participation in existing ECO programs. Therefore, the Company plans to propose the application as a new measure within the ECO portfolio, using the existing ECO modification process. Specific costs will be proposed as part of that proceeding and, if approved, would be recovered through the existing CIP/ECO tracker. Costs for other DI products that focus on providing other services would be recovered via an appropriate mechanism based on the nature of the service. For example, we would seek recovery of operations and maintenance costs for grid-facing use cases in a future rate case. We note that DI investments will be in-service when we reach 80 percent meter deployment.

III. DATA ACCESS FOR HAN, AMI, AND DI

Order Point 17 of the Commission's June 28, 2023 Order in Docket No. E002/M-21-814 states:

> *Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing:*
>
> *a. HAN, AMI and AMI-DI specifications and related customer data access policies.*
> *b. Bring-your-own device HAN requirements and terms.*
> *c. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN.*
> *d. Methods to provide customers equal access to the level of data available to the utility.*
> *e. A summary of industry customer data access standards.*

In this section, we discuss the processes in place that enable data access for HAN, AMI, and DI.

A. HAN, AMI, and DI specifications and related customer data access policies

We understand this requirement to be seeking information on products and tools enabled by HAN, AMI, and DI and the Company's associated policies related to customer data access. The Company has multiple products that allow third parties to access customer data with consent from the customer. For example, Green Button Connect is a product that allows an eligible customer to provide their energy usage data to an authorized third-party with the click of a button within their My Account. Green Button Connect is available to any residential customer today, regardless of meter type.

Third parties can also utilize the Company's BYOD and gateway SDKs, discussed above, to develop hardware and software products that connect to the customer's smart meter via the HAN. The SDK solution uses a third-party software application residing on either a local computer or local computing device to pull data from the meter and transfer it to a designated third-party. The application will poll the customer's configured meter using the IEEE 2030.5 protocol to gather the customer's energy usage data periodically. The application will then transfer the data to the designated third-party. In this solution, the third-party would be responsible for the development of the local data transfer application while the Company would retain responsibility for the configuration of the meter.

Xcel Energy Launchpad allows customers to connect applications or devices developed by third parties to the AMI meters through the customer's home Wi-Fi network over the DI-enabled HAN. This permits the customer and third party to directly gather one-second energy consumption information from the meter. Customers can enroll in Xcel Energy Launchpad through their My Account. The Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network.

Currently, the following data can be accessed by customer-authorized third parties via the SDK:

- Instantaneous Demand: Real-time meter data in Watts.
- Current Summation Received (locally produced power): Accumulated kWh since the meter was installed.
- Current Summation Delivered (grid produced power): Accumulated kWh since the meter was installed.

B. Bring-Your-Own-Device HAN Requirements and Terms

Third parties interested in accessing the SDK with BYOD capabilities are required to fill out a form available on the Company's website at xcelenergy.com/s/forms/sdk-access. Once a form has been submitted, a Company employee will add that user to the SDK repositories. From there, the user can access both the BYOD SDK and the gateway SDK at the GitHub repository portal. They can also submit issues for questions or troubleshooting items within GitHub. The Company adds the new user to the SDK GitHub repository within five business days. Any third party or individual customer that fills out the form can access the SDK.

For the Company's customers, the Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network. Customers must also provide consent to connect third party devices to the meter via their Wi-Fi network and the HAN.

The planned terms and conditions of the Xcel Energy Launchpad are below. We intend to seek approval for the Xcel Energy Launchpad terms and conditions to be included in the Company's Electric Rate Book, in an upcoming filing.

> Xcel Energy Inc. and each of its affiliated companies ("Xcel Energy") and each of the Third-Party Service Providers are independent parties. If you acquire any of the products or services offered by these software developers, you are acquiring the products or services directly from those independent software developers. As independent parties, the Third-Party Service Providers are solely responsible for their products and services, and any claims, damages or other liability which may arise from their products or services or the performance of their products or services.
>
> You are responsible for your selection of any product or service offered by a Third-Party Service Provider. Xcel Energy is not responsible for examining or evaluating, does not endorse, and does not warrant or guarantee, any Third-Party Service Provider product or service. Xcel Energy does not assume any responsibility or liability for the actions, products, or services of all these and any other third parties and you hereby release and hold Xcel Energy harmless from any claim or damage which may arise out of your authorization given under these terms, the third-party products or services or your use of the products or services.

By authorizing a Third-Party Service Provider to connect to the Xcel Energy meter installed on your premise, you understand that you are granting an independent party permission to access kilowatt (kW) and kilowatt-hour (kWh) data at one-second or five-second intervals from your premise receiving utility service.

Access to the data can provide insight into activities within your premise receiving utility service.

You are not required to authorize any Third-Party Service Provider to connect to the Xcel Energy meter installed at your premise and not authorizing the connection will not affect your utility services.

Xcel Energy will have no control over the data once it is disclosed to a Third-Party Service Provider pursuant to your authorization and will not be responsible for monitoring or taking any steps to ensure that the Third-Party Service Provider maintains the confidentiality of the data or uses the data as authorized by you. Please be advised that you may not be able to control the use or misuse of the data once the Third-Party Service Provider has connected to the meter installed at your premise.

If you decide to rescind your authorization and terminate the Third-Party Service Provider connection, you may do so at any time by 1) by visiting your Xcel Energy My Account customer portal and by visiting your Xcel Energy My Account customer portal and unenrolling from the service, or 2) by sending a written request with your name and service provider to EnergyLaunchpad@xcelenergy.com, or 3) by calling Xcel Energy's customer service center at 1-800-895-4999.

For additional information, including the Xcel Energy's privacy policy, visit https://my.xcelenergy.com/s/privacy.

By clicking the link below and proceeding beyond this authorization, you acknowledge and agree that you are the customer of record for this account and that you authorize the Third-Party Service Provider to connect to the meter installed at your premise.

C. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN.

The Company maintains administrative, technical, and physical safeguards designed to protect the privacy and security of the customer information that the Company maintains. Among other protections, these safeguards are designed to restrict access to customer information only to those Company employees and contracted agents that require access for an identified business purpose. Unless disclosure of customer information is specifically permitted or required by applicable law or regulation, the Company will only share customer information after obtaining the customer's explicit consent.

As such, while the Company does not currently require authorized third parties to accept terms and conditions in order to access data via the HAN, customers must provide explicit consent before any third-party gains access to the customer's meter and data.

For My Energy Connection, we intend to seek Commission approval of the Terms & Conditions to be included in the Electric Rate Book in an upcoming filing.

D. Methods to provide customers equal access to the level of data available to the utility

We understand this requirement to be seeking information on how the Company provides, or could provide, customers with their own usage data and details. The Company has developed several products that enable customers to access demand, interval data, and billing data including:

- **My Energy Portal.** Within My Energy Portal linked to My Account, customers can view their 15-minute, hourly, daily, monthly, and yearly usage data. Customers can toggle between kilowatt-hour usage and cost for each view. Using this presentment tool enhances the customer experience by helping customers better understand their usage patterns. All customers have access to My Energy Portal through My Account; customers with an AMI meter have access to 15-minute, hourly, and daily data. This functionality does not rely on DI.
- **On Demand Meter Reads.** The On Demand Read functionality in My Account provides AMI customers the ability to see their 15-minute interval kilowatt-hour usage for the last eight hours. The On Demand Read functionality provides customers options to experiment with turning

appliances and other equipment on and off to identify their energy usage patterns. This functionality does not rely on DI.

- **Green Button Connect.** Green Button Connect (GBC) is an ongoing electronic data transfer service that allows customers to share their utility data to authorized service providers. These service providers can help customers make smarter choices about their energy usage by providing tools and applications to help them find ways to save energy. Customers can sign up for GBC in the Xcel Energy My Energy Portal and select which service providers to send their data to and how long to share their data with them. GBC sends the premises' billing and usage data down to 15-minute intervals for customers with AMI meters, but GBC is available to all customers regardless of meter type and does not rely on DI.
- **Green Button Download my Data.** Green Button Download is a one-time secure data download of a customer's energy usage to their computer. Customers can access Download My Data through the My Energy Portal and download a copy of their usage for personal records or to share with a vendor for energy savings projects. All customers have access to Green Button Download My Data, and customers with AMI meters can download 15-minute interval data.

In addition, the Company is developing a DI-enabled mobile application – My Energy Connection, discussed above – that will enable customers to view real-time and historical energy usage on a mobile device. The mobile application will also enable customers to view:

- Real-time whole home W
- 15-min interval kWh updates while not connected to Wi-Fi
- Current (current day, current week, and current month) whole home kWh and cost
- Historical (yesterday, prior week, and prior month) whole home kWh and cost
- Current Rate
- Comparison to yesterday's and last week's usage (against today's and this week's usage)
- Comparison to last log-in real-time whole home W (against current real-time whole home W)
- TOU periods (hours, period names, and rate) displayed, if applicable
- Savings Tips displayed by category

E. Industry Customer Data Access Standards

The Company's customer data access standards are consistent with industry best practice. The Company will only release customer confidential restricted information pertaining to an individual to that individual once the identity of the individual has been validated. We will release customer confidential information (CI) to the customer of record upon validating the customer's identity, or to a third party upon receiving a documented and verified consent from the customer of record. We may also disclose customer CI as required or permitted by law or applicable regulations, including to a federal, state, or local governmental agency with the power to compel such disclosure, or in response to a subpoena or court order. (For further discussion of how we classify customer information, see *Appendix B2: Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies*.)

We also release customer information to our contracted agents when it is necessary for our agent to perform the service(s) specified in an Agreement. All of our contracted agents go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to the Company as a direct result of utilizing a third-party vendor's product, service, application, etc. All newly proposed vendor arrangements are subject to the (S)VRA process before a contract is signed. Suppliers are assessed by our internal Enterprise Security and Emergency Management (ESEM) to ensure security risk is addressed. We prohibit these service providers from using or disclosing the information we provide them, except as necessary to perform specific services on our behalf or to comply with legal requirements.

For information about the Company's policies, practices, and protocols regarding the release of customer data to customers or third-parties upon request the request of a customer, please see our most recent Annual Report of customer data release practices.[3]

[3] Xcel Energy Compliance Filing – Annual Report on Privacy Policies and Open Data Access Standards, Docket Nos. E,G999/CI-12-1344 and E,G999/M-19-505 (March 1, 2023).

IV. COLORADO DISTRIBUTED INTELLIGENCE SETTLEMENT AGREEMENTS

In 2021, the Company filed an application with the Colorado Public Utilities Commission (CPUC) requesting an Amendment to the Certificate of Public Convenience and Necessity (CPCN) issued for the Company's Advanced Grid initiative. Through the Application the Company requested, amongst other things, the CPCN be amended to allow the Company to deploy certain DI capabilities on the Company-selected AMI meters.

A Unanimous Comprehensive Settlement Agreement was reached in 2022.[4] As a result of the Settlement, three products were created to enable customers to share data with third parties. The three products created – the Software Development Kit (SDK), Bring Your Own Device (BYOD), and Xcel Energy Launchpad – are available to all customers and third parties regardless of location.

The Company intends to deploy additional DI applications at the enterprise level, meaning modifications made to the applications in response to the Colorado DI Settlement will have implications for the Minnesota releases as well. In the following section, we outline the Colorado DI Settlement agreements and note implications for Minnesota.

Overall, our DI plans in Minnesota are consistent with the Colorado DI Settlement, which allows us to leverage efficiencies across states and jurisdictions and maximize the benefits of our investments for Minnesota customers. This approach allows us to provide Minnesota customers with access to DI tools and apps as they become available at the enterprise level. The Minnesota Public Utilities Commission retains authority to adjust our plans and, during a cost recovery proceeding, determine the prudency of our investments in Minnesota.

For a complete view of the Terms and Conditions of the Colorado DI Settlement, see Attachment L.

A. Third-Party Access to Data of One Second of Resolution

Section II.D. of the Colorado DI Settlement requires the Company to deploy BYOD functionality to allow IEEE 2030.5-compliant devices to connect to the AMI meter

[4] Decision No. R22-0131 issued in Proceeding No. 21A-0279E approved the Unanimous Comprehensive Settlement Agreement.

via a two-step authentication process. In order to facilitate BYOD, the Company agreed to make a SDK available to developers free of charge. Both products were deployed on September 23, 2022 and are available to developers regardless of location.

The Company hosted four different workshops for developers that outlined what the SDK is and how they could use it. The Company reached out to the parties to the Amended AGIS CPCN and asked them to provide names and contact information for anyone they were aware of that would be interested in participating in the workshops. Approximately 63 interested parties attended the workshops.

The Company also sponsored and attended a developer conference called Open Source North in Saint Paul, Minnesota. At this conference, employees engaged with approximately 600 attendees and promoted the Xcel Energy Launchpad. The Company received multiple new signup requests linked to the conference.

The Company also developed the Xcel Energy Launchpad, which allows customers to connect applications or devices developed by third parties to the Advanced Meters through the customer's home Wi-Fi network over the DI-enabled Home Area Network (HAN). This permits the customer and third party to directly gather one-second energy consumption information from the meter.

The Company has not actively marketed the Xcel Energy Launchpad to customers yet as we are not aware of any available third-party products that use the capability.

Any customer with an AMI meter, including in Minnesota, can enroll in Xcel Energy Launchpad through their My Account. The Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network. Customers must also provide consent to connect third party devices to the meter via their Wi-Fi network and the HAN.

The SDK, BYOD, and Xcel Energy Launchpad are accessible to customers with AMI meters in all states.

B. Third Party Support

Section III of the Colorado DI Settlement also requires the Company to provide appropriate documentation with the SDK, including code examples and a working sample set of software sufficient to allow a third-party developer to implement either a hardware or software solution that will allow a customer-approved external third party located remotely from the customer premise to access the one-second data measured by the meter via its existing IEEE 2030.5 interface.

In addition, the Company committed to:

1. Providing up to 2,000 hours of technical support in total on a first-come, first-serve basis, to third parties in support of the SDK; and
2. Conducting at least four workshops for developers.

Itron was selected as the SDK technical support vendor for the first year after its release. The technical support contract cost approximately $230,000 per year and is recovered from Colorado customers. In the Company's Data Delivery Application to the CPUC, the Company proposed changing vendors and transitioning from a fixed cost model to a time and materials (T&M) model in an effort to lower the cost of the support to align with the demand. In addition, the Company proposed transitioning the technical support costs from customers to third parties.

The Company hosted four workshops for developers to provide information on the BYOD and SDK functionality including how to access the products and how to get support.

Any third party, regardless of geographic region, was allowed to participate in the workshops. The Company reached out to the parties to the Settlement and asked them to provide a list of anyone they were aware of that was interested in participating in the workshops. From that list, a total of 63 interested parties were invited to the workshops.

C. Data Delivery Study

Section IV of the Colorado DI Settlement required the Company to study the feasibility, costs, benefits, security implications, and other attributes of the various technical options to deliver one-second timestamped data, including, but not limited to, power, energy, voltage, volt-amps reactive data; applicable rate; meter identifier; and disaggregation insight data to customer-authorized third parties legally permitted to receive such data. The goals of the study were to perform a technical analysis to identify potential methods and evaluate the impact of those methods across business processes, process automations, employee workload, reporting, and organizational structure.

The Company met with stakeholders early in the study development process and prior to the study's completion to provide stakeholders an opportunity to provide feedback on the draft report prior to submittal to the Commission. The four methods evaluated included (1) direct data upload (2) Itron cloud (3) Xcel Energy cloud and (4) local polling application.

The study was finalized and filed with the CPUC in March 2023.[5] The scope was not limited to Colorado. The findings are applicable to all jurisdictions including Minnesota. The delivery of data directly from the meter to the third parties, or the Direct Data Upload solution, was not deemed feasible due to a separation of duties security control which restricts the DI agents from having direct access to the communications networks. The Itron and Xcel Energy Cloud solutions were technically feasible but have not yet been developed or are very new to market. The cloud solutions would cost between $22 million and $30 million to develop and result in a reoccurring operating and maintenance cost of $1.4 million to $12.5 million per year. The fourth solution, local polling application, met one second kW and five second kWh requirements and was the lowest cost solution. The study estimated the local polling solution would cost between $9.6 and $15.2 million to implement and result in a reoccurring cost of $400 thousand to $2.3 million. This solution was developed by the Company and released for public use in September 2022. It includes the SDK, BYOD, and Xcel Energy Launchpad applications.

To date, the Company has spent $5 million developing the SDK, BYOD, and Xcel Energy Launchpad. These applications cost nearly $1 million per year to maintain. This is less than the study estimated cost of $9.6M to $15.2M since it is only the initial develop cost and does not include future updates to the meter agent.

D. Data Delivery Application

As required by the Colorado DI Settlement, on September 22, 2023, the Company filed an application (Proceeding No. 23A-0471E) with the CPUC describing the Company's proposal for delivering one-second timestamped data to customer-authorized third parties legally permitted to receive the data.

The Company currently has three products that enable customers to share one-second data with authorized third parties via a local polling application. The solutions explored in the Data Delivery Study that would expand the data sharing capabilities

[5] Data Delivery Study available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=992817&p_session_id=.

above and beyond the local polling application have not been developed yet and would be expensive to build today. At the time of this filing, a relatively low number of entities are using the existing local polling application; therefore, the Company does not believe the demand for a data sharing mechanism necessitates a rushed investment approach. As a result, in the September 22, 2023 filing in Colorado, the Company proposed the existing local polling application remain in place as the method to deliver one-second timestamped data with the caveat that if the SDK is not being used, it may sunset in two years.

The existing polling applications are available and compatible with meters installed in all states, including Minnesota. If the Colorado application is approved, Minnesota customers would continue to be able to use the existing local polling applications unless demand is low, and the SDK sunsets. If the CPUC denies the application and requires a change to the Company's data delivery method, the change would be implemented enterprise-wide and accessible to customers in all states, including Minnesota.

E. HAN/Customer Outreach and Education

In Section II.G of the Colorado DI Settlement, the Company agreed to conduct customer outreach and education regarding the HAN capability generally consistent with the Advanced Grid Education Plan filed in CPUC Proceeding No. 16A-0588E. Such outreach would describe the BYOD capability generally and not narrowly focus on the Company's HAN mobile application.

The Company sponsored and attended a developer conference called Open Source North in Saint Paul, Minnesota. At this conference, employees engaged with approximately 600 attendees and promoted the SDK. The company received multiple new SDK signup requests linked to the conference.

The Company has not done direct outreach and education to customers regarding the HAN capability or Xcel Energy Launchpad yet, since the Company is not aware of any third-party products available to customers today that use the HAN capability. However, the Company is currently developing a mobile application called My Energy Connection, as discussed above, which would use the HAN capability to display real-time energy data to customers. When this application is released, the Company will conduct outreach to customers in all states with AMI meters to notify them of the capability.

F. HAN Functionality

Section II.H of the Colorado DI Settlement states that if the Company makes updates to IEEE 2030.5 functionality or function sets over time that are not reverse compatible, the Company shall provide at least 180-days advance notice to affected customers and shall make best efforts to communicate the upcoming change to affected HAN device and software makers. Such notice shall include information necessary for adapting HAN device or software to the modifications.

Fulfillment of this commitment is not limited to Colorado. All affected customers, regardless of geographic region, would be notified of changes to the HAN functionality.

G. Green Button Connect My Data

In Section V of the Colorado DI Settlement, the Company agreed to modify the Green Button Connect (GBC) terms and conditions that appear on the Company's website. The updated terms and conditions are applicable and available to all customers regardless of geographic region.

H. EV Load Disaggregation Pilot

Further, the Company committed to file a report on the EV Load Disaggregation Pilot initiated during the 2021-2023 Colorado Transportation Electrification Plan (TEP) in the Company's 2024-2026 Colorado TEP (Docket No. 20A-0204E). An update on the pilot was included in the Colorado 2024-2026 TEP (Docket No. 23A-0242E).

The EV Load Disaggregation Pilot as well as the cost recovery for the pilot is currently limited to Colorado.

I. Grid-Facing DI Capabilities

To facilitate transparency with regards to distribution system planning, the Company committed to hosting at least one stakeholder meeting per year regarding its development of Grid-Facing DI Capabilities that are in the normal course of business. While the commitment was specific to Colorado, in Minnesota, the plan for Grid-Facing DI Capabilities have been discussed in IDP workshops in 2023.

J. Customer-Facing DI Applications

The Colorado DI Settlement prohibits the Company from recovering costs for, or deploying Customer-Facing DI Capabilities until the Company receives approval from the CPUC after filing an application on a case-by-case basis.

Customer-Facing DI Capabilities are described in the Settlement as solutions and services enabled or supported by Load Disaggregation Capabilities on Advanced Meters, which provide analytical disaggregation of electric load inside the premise into end uses. The Customer-Facing DI Capabilities definition in the Settlement excludes solutions and services enabled or supported by analytical disaggregation of electric load through: (1) interval data recording at 5-minute or 15-minute intervals; and, (2) one-second or greater HAN data, which means these solutions are allowed per the Colorado DI Settlement.

My Energy Connection Release 1, which will be available to Minnesota customers and is discussed below, provides 1-second, whole home energy data to customers and is allowed per the Colorado DI Settlement. As of the time of this filing, the Company's proposed solution for Release 2 will not include sub-second disaggregation and is therefore, not prohibited in Colorado.

K. Reporting Requirements

The Colorado DI Settlement includes reporting requirements such as filing retrospective information about applications deployed on meters including, but not limited to, estimated typical and maximum remaining memory and processing power available to host Grid-Facing DI Capabilities and Customer-Facing DI Capabilities; an accounting of the costs incurred; a discussion of the benefits delivered to customers; and a list of DI applications that have been uninstalled or terminated in any manner, and a description of the circumstances.

The Company will also provide a non-binding description of the Company's plans for developing Customer-Facing and Grid-Facing DI Capabilities in the next two years, including the expected benefits and timelines for these capabilities.

In Minnesota, related reporting could be required as a condition of approval of a future DI cost recovery request. We also note that the AMI Annual Report required as per the Transmission Cost Recovery (TCR) Rider Order[6] will include information

[6] *See* the Commission's June 28, 2023 Order in Docket No. E002/M-21-814, at Order Point 10.

similar to that required by the Colorado DI Settlement, including:

- Percentage and number of customers with HAN functionality,
- Third-party service access to customer data,
- Variety, quality, accessibility of customer data available,
- A comprehensive account of all functionalities achieved and any changes to functionality or potential future uses,
- Description and explanation of any functionalities that have been disabled, and
- Revenue-generating opportunities identified or engaged that relate to the use of AMI, FAN, or DI technologies.

L. Unregulated Affiliates / Unregulated Offerings

As part of the Settlement, the Company committed to establishing guidelines to help ensure that unregulated affiliates or any unregulated offerings of the Company itself will not obtain preferential treatment compared to non-affiliated third parties by the Company for the use of DI. We will follow these guidelines in all jurisdictions, including Minnesota.

M. Deferred Cost Recovery

The Settling Parties agreed that the costs to the Company of carrying out the commitments of HAN deployment and conducting the data delivery study, inclusive of costs to prosecute the application filed in Colorado on September 22, 2023, may be deferred in a Colorado regulatory asset without carrying costs. No presumption of prudence will apply to such costs as a result of the proceeding, and deferred costs will not exceed $2.5 million. We are not proposing cost recovery or cost recovery paths with this IDP filing but note that, consistent with the Colorado DI Settlement, any outcome of this IDP will not result in a presumption of prudence and the Company will bear the burden of demonstrating prudence of DI investments in any future cost recovery filing.

N. Electric Tariff Revisions

The Settling Parties agreed that the following sentences should be added to Sheet No. R87 of the Public Service of Colorado Company's Electric Tariff: "The Company shall not be liable for any monetary loss or physical damage resulting from any loss of, diminished quality of, or interruption to data regarding Customer's energy consumption stemming from causes beyond the Company's control."

This change has been made to the Colorado Company's Electric Tariff. In Minnesota, we may explore adding the same or a similar provision to our Electric Tariffs in the future.

V. CONCLUSION

We are excited about the capabilities that DI offers and are moving forward with a measured, enterprise-wide plan that will benefit all customers as we prepare for the future. In the near-term, our Minnesota customers will have access to My Energy Connection releases, Software Development Kits, and Xcel Energy Launchpad and their benefits before the Company seeks cost recovery through a future proceeding. This approach allows us to leverage economies of scale across our jurisdictions without delaying the benefits for Minnesota. We look forward to providing more information in future cost recovery proceedings and demonstrating the prudence of our investments.

IDP Piece	Title	Non-Public Designation
Appendix H10	Commercial EV Pilot Project-by-Project Detail	Please note that Appendix H10 is marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
Attachment D	Distribution Risk Scoring Methodology	Attachment D Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.
Attachment E	Risk Scored Project Details	Attachment E contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

Statute	Requirement
Minn. Stat. § 216B.2425, subd. 2(e).	In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.
Minn. Stat. § 216B.2425, subd. 3.	Subd. 3.Commission approval. By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. The commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is: (1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers; (2) needed, applying the criteria in section 216B.243, subdivision 3; and (3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.
Minn. Stat. § 216B.2425, subd. 9.	The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023: 1) a forecast of distribution system upgrades necessary to accomodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects including energy storage systems; 2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and 3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
	Planning Objectives	The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans 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; and, 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs. 5. Provide the Commission with the information necessary to understand Xcel'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.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
		Commission review of ~~annual~~ distribution system plans ~~are~~ is[1] not meant to preclude flexibility for Xcel to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments. [1] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan and Modifying Filing Requirements (Nov. 2, 2020), Ordering Para. 4.*	N/A
		For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement: 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive; 2. How the information could be obtained, at what estimated cost, and timeframe; 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives; 4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.	Appendix A4: Distribution System Statistics
		Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: 1. An analysis of how the information presented in the IDP related to each Planning Objective, 2. The location in the IDP, 3. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and 4. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives[2] *2 In the Matter of Xcel Energy's 2018 Integrated Distribution Plan, Docket No. E-002/CI-18-251, Order Accepting Report, and Amending Requirements (July 16, 2019), Ordering Para. 5.*	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
1	Filing Date	Filing Date: Require Xcel to file annually with the Commission beginning on November 1, 2018, and biennially starting Nov 1, 2021[3] an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. Xcel must continue to file an annual update of baseline financial data and non-wires alternatives analysis.[4] The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776). [3] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (July 23, 2020), Ordering Para. 2.* [4] *July 23, 2020, Order (19-666) Ordering Para. 3*	This biennial IDP is being submitted November 1, 2023 in compliance with this requirement.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Stakeholder Meeting(s): Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	Appendix G: Stakeholder Engagement
3	Filing Requirements	Filing Requirements: For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[5] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.[6] [5] *See Minnesota Staff Grid Modernization Report, March 2016.* [6] *See report on IDP prepared for the Commission by consultants ICF International, in In the Matter of the Commission Investigation into Grid Modernization, Docket No. E-999/CI-15-556, Notice of Integrated Distribution Planning Report and Stakeholder Workshop (September 13, 2016), eDockets ID: 20169-124836-01.*	Integrated Distribution Plan - Main Repot, VII.
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	Appendix A1: System Planning
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	Appendix A4: Distribution System Statistics
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	Appendix A4: Distribution System Statistics
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available	Appendix A4: Distribution System Statistics
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including a. Setting the forecasts for distributed energy resources consistently in its resource plan and its IDP b. Conducting advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours[7] [7] July 26, 2022, Order (21-694) Ordering Para. 4	Appendix A1: System Planning Appendix F: Non-Wires Alternatives Analysis
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	Appendix A1: System Planning

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018[8] impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018). [8] IEEE Standard 1547-2018 published April 6, 2018.	Appendix E: System Interconnection and Distributed Energy Resources
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	Appendix A4: Distribution System Statistics
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	Appendix A4: Distribution System Statistics
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	Appendix A4: Distribution System Statistics
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	Appendix A4: Distribution System Statistics
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	Appendix A4: Distribution System Statistics
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	Appendix A4: Distribution System Statistics
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	Appendix A4: Distribution System Statistics
3.A.15	Baseline Distribution System and Financial Data System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty)[9] [9] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting Filings and Establishing Requirements for Additional Filings (December 12, 2019), Ordering Para. 8.a.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations[10] b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program[11] c. Number and capacity of known public access direct current fast charging (DCFC) stations[12] d. Number and capacity of DCFC installed through a utility EV program, broken out by program[13] e. All other known EV charging stations (by type, ex DCFC, Level 2) [10] December 12, 2019 Order (17-879), Ordering Para. 8.e [11] December 12, 2019 Order (17-879), Ordering Para. 8.e [12] December 12, 2019 Order (17-879), Ordering Para. 8.f [13] December 12, 2019 Order (17-879), Ordering Para. 8.f	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.26	Baseline Distribution System and Financial Data System Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs[14] 1. Capital Costs 2. O&M Costs 3. Marketing & Communications 4. Other (provided explanation of what is in "other") The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization For each category, provide a description of what items and investments are included. [14] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (April 16, 2021), Ordering Para. 3.a.	Appendix D: Distribution Financial Framework and Information

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.27	Baseline Distribution System and Financial Data System Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.28	Baseline Distribution System and Financial Data System Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	Appendix D: Distribution Financial Framework and Information
3.A.29	Baseline Distribution System and Financial Data System Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs[15] 1. Capital Costs 2. O&M Costs 3. Marketing & Communications 4. Other (provided explanation of what is in "other") [15] April 16, 2021 Order (17-879), Ordering Para. 3.a	Appendix D: Distribution Financial Framework and Information Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend Attachment J: O&M Profile Trend
3.A.30	Baseline Distribution System and Financial Data System Data	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	Appendix A1: System Planning
3.A.31	Baseline Distribution System and Financial Data System Data	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.34	Electric Vehicles	Electric Vehicles: A summary table with the following information for each EV rate offering or program during the reporting period: a) Number of customers and/or vehicles enrolled at the end of the reporting period b) Total energy consumed) MWh) during each EV tariff charging period c) Peak demand (MW) and the date and time at which occured[16] [16] December 12, 2019 Order (17-879), Ordering Para. 8b, 8c, and 8d	Appendix H: Transportation Electrification Plan
3.A.35	Electric Vehicles	Electric Vehicles: Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify)[17] [17] December 12, 2019 Order (17-879), Ordering Para. 8g; April 16, 2021 Order (17-879), Ordering Para. 3.b	Appendix H: Transportation Electrification Plan

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources[18], and any other method in which Xcel anticipates customer benefit stemming from the annual HCA. [18] Minn. Stat. 216B.2425, Subd. 8	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.[19] [19] In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Docket No. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018), establishing Minnesota's Distributed Energy Resources Interconnection Process (MN DIP) 3.2, "Initial Review."	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first. Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.[20] For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).[21] [20] July 23, 2020 Order (19-666), Ordering Para. 4 [21] December 12, 2019 Order (17-879), Ordering Para. 8h and 8i	Appendix A1: System Planning
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	Appendix A1: System Planning
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841[22] (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators) [22] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶61,127 (February 28, 2018)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*[Merged into 3.D.2 per July 16, 2019 Order, Order Point 4] 18-251*	N/A

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Xcel shall provide a 5-year Action Plan as part of a 10-year long term plan[23] for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER future analysis, hosting capacity analysis[24], and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). 23 Modified by July 16, 2019, Order (18-251), Ordering Para. 4 24 Modified by July 16, 2019, Order (18-251), Ordering Para. 4	Appendix A1: System Planning, Appendix C: Action Plans Appendix D: Distribution Financial Framework and Information Attachment F: Planning Area Load Growth Assumptions, Attachment H: Capital Project List by IDP Category
		Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	See 3.D.2 Subparts below.
3.D.2.a	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Overview of investment plan: scope, timing, and cost recovery mechanism	Appendix C: Action Plans Appendix D: Distribution Financial Framework and Information
3.D.2.b	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[25] [25] See https://gridarchitecture.pnnl.gov/	Appendix B1: Grid Modernization
3.D.2.c	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	N/A - no investment proposal
3.D.2.d	Long-Term Distribution System Modernization and Infrastructure Investment Plan	System interoperability and communications strategy	Appendix B1: Grid Modernization
3.D.2.e	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	Appendix A1: System Planning
3.D.2.f	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Appendix C: Action Plans
3.D.2.g	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer anticipated benefit and cost	Attachment D: Distribution Risk Scoring Methodology Attachment E: Risk Scored Project Details Attachment G: Distribution Function NPV We note we are not requesting certification of any grid modernization investments.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.D.2.h	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Appendix B2: Operational and Planning Data Management, Security, and Information Access Plans and Policies Appendix J: Distributed Intelligence
3.D.2.i	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Plans to manage rate or bill impacts, if any	Appendix C: Action Plans
3.D.2.j	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Attachment G: Distribution Function NPV
3.D.2.k	Long-Term Distribution System Modernization and Infrastructure Investment Plan	For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.[26] [26] *July 16, 2019, Order (18-251), Ordering Para. 3*	No new grid modernization projects in 5-year Action Plan. CBAs provided in Docket Nos. E999/M-15-962; E002/M-19-666; E002/M-21-184; E002/GR-21-630
3.D.2.l	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Status of any existing pilots or potential for new opportunities for grid mod pilots.	Appendix B3: Existing and Potential New Grid Modernization Pilots
3.D.2.m	Long-Term Distribution System Modernization and Infrastructure Investment Plan	The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.[27] [27] July 16, 2019, Order (18-251), Ordering Para. 9	Attachment D: Distribution Risk Scoring Methodology
3.D.2.n	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs[28] [28] July 16, 2019, Order (18-251), Ordering Para. 10	Attachment E: Risk Scored Project Details
3.D.2.o	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Long-range distribution studies conducted since the last IDP[29] [29] July 16, 2019, Order (18-251), Ordering Para. 11	N/A; addressed in Appendix A1: System Planning
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	Appendix C: Action Plans
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall 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.	Appendix F: Non-Wires Alternatives Analysis

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b.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) c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed d. 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.	Appendix F: Non-Wires Alternatives Analysis
3.F.1	Transportation Electrification Plan	Xcel shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.[30] [30] December 12, 2019 Order (17-879), Ordering Para. 8j	Appendix H: Transportation Electrification Plan
3.F.2	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to facilitate:[31] a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory b. availability of residential charging options for both single family and multiple unit dwellings c. programs or tariffs in development to address flexible load or reduce metering and data costs; and d. fleet electrification. [31] December 12, 2019 Order (17-879), Ordering Para. 8k	Appendix H: Transportation Electrification Plan
3.F.3	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.[32] [32] December 12, 2019 Order (17-879), Ordering Para. 8m	Appendix H: Transportation Electrification Plan
3.F.4	Transportation Electrification Plan	Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.[33] [33] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Informational Requirements (May 17, 2022), Ordering Para. 4.	Appendix H: Transportation Electrification Plan
3.F.5	Transportation Electrification Plan	Xcel shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 20-745 at the conclusion of the pilot program.[34] [34] In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Programs as part of its COVID-19 Pandemic Economic Recovery Investments, Docket No. E-002/M-20-745, Order Approving Public Charging Station Proposal (April 27, 2022), Ordering Para. 8.	Appendix H: Transportation Electrification Plan
3.F.6	Transportation Electrification Plan	Xcel shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.[35] [35] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (Apr 16, 2021), Ordering Para. 3.c.	Appendix H: Transportation Electrification Plan
3.F.7	Transportation Electrification Plan	Xcel shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.[36] [36] December 12, 2019 Order (17-879), Ordering Para. 8l	Appendix H: Transportation Electrification Plan
3.F.8	Transportation Electrification Plan	Xcel shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).[37] [37] December 12, 2019 Order (17-879), Ordering Para. 8n	Appendix H: Transportation Electrification Plan
3.F.9	Transportation Electrification Plan	Xcel shall provide citations with links to the most recent reports for any ongoing EV pilots or programs.[38] [38] December 12, 2019 Order (17-879), Ordering Para. 8o	Appendix H: Transportation Electrification Plan
3.F.10	Transportation Electrification Plan	Xcel shall provide historical spending for the past 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Appendix H: Transportation Electrification Plan
3.F.11	Transportation Electrification Plan	Xcel shall provide future spending for the next 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Appendix H: Transportation Electrification Plan

Order Point	MPUC IDP Requirement (8/7/18 Order in Docket No. E002/M-17-775 & E002/M-17-776)	Location
11	Xcel may file a Grid Modernization Report and certification request on November 1, 2018 in combination with an Integrated Distribution Plan in Docket No. E-002/CI-18-251. The filing should include for any certification request(s) at a minimum: (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission’s Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel’s long-term grid modernization plans.	N/A
Order Pt.	**MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)**	**Location**
6	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	Not applicable for 2023 IDP. See Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6.
7	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company’s 2019 IDP.	Not applicable for 2023 IDP. No longer relevant - provided in Docket No. E002/M-19-666.
8	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	Not applicable for 2023 IDP. No longer relevant - provided in Docket No. E002/M-19-666.
Order Pt.	**MPUC IDP Requirement (7/23/20 Order in Docket No. E002/M-19-666)**	**Location**
5	Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.	Appendix G: Stakeholder Engagement
6	Xcel must engage stakeholders in further advancing the Company’s NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.	Appendix G: Stakeholder Engagement
9	The Commission requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. **Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.**	Not applicable for 2023 IDP. Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020)

12	Xcel must produce a draft rate design "roadmap" with input from stakeholders and file it with the Commission by October 1, 2020. The Commission delegates authority to the Executive Secretary to set schedules and gather information on, or refer to the appropriate docket(s), the following: a. A summary of the Company's current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices. b. A timeline for proposing advanced rates and/or demand management programs for all customer classes. c. A discussion on what should be discussed in petitions for rate design changes, including: i. Whether program design strategies will be needed to support low income customer participation in these offerings, ii. Application to distributed energy resources and beneficial electrification, iii. Implementation plans, including education and outreach to customers, and	Not applicable for 2023 IDP. Filed 10/1/2020 in Docket No. E002/M-19-666
13	60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.	Not applicable to 2023 IDP. Filed 8/28/2020 in Docket No. E002/M-19-666
Order Pt.	**MPUC IDP Requirement (11/2/20 Order in Docket No. E002/M-19-666)**	**Location**
4	Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association's IDP filing requirements in the second paragraph under Planning Objectives are corrected as shown: Commission review of ~~annual~~ distribution system plans are is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.	See IDP Planning Objectives for Xcel Energy with the 12/8/22 Order.
Order Pt.	**MPUC IDP Requirement (7/26/22 Order in Docket No. E002/M-21-694)**	**Location**
2	Xcel shall file its smart inverter roadmap and related consultant reports in this docket by November 1, 2022	Submitted in Annual Update, Attachment E, submitted 11/1/2022 in Docket No. E002/M-21-694.
3	Xcel shall use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting.	Appendix F: Non-Wires Alternatives Analysis

5	Within 90 days, Xcel shall make a compliance filing that outlines key difference between its Colorado and Minnesota distribution system planning processes, including but not limited to a discussion of the following: a. Orders, rules, and statutes pertaining to distribution system planning b. How Xcel Energy conducts DER and load forecasting, including the Company's implementation of LoadSEER c. How Xcel Energy conducts its NWA analysis d. How Xcel Energy conducts its Hosting Capacity analysis	Compliance filing submitted 10/24/2022 in Docket No. E002/M-21-694.
6	Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans. This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings. The topics will include, but not be limited to the following: a. Integrated Distribution Planning 101 b. Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term. c. How energy efficiency, demand response, and other DER might impact Xcel's planning processes d. How Xcel should consider and incorporate local clean energy goals in its planning processes e. What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments	Appendix G: Stakeholder Engagement & Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694.

6 (Continued)	f. Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes g. Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions h. Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts i. How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast j. Estimate the potential synergies between interconnection upgrades sand planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system. Xcel shall make a compliance filing with the summary of the stakeholder process and a list of next steps by August 1, 2023. Xcel shall include a summary of the stakeholder series in its next IDP and relevant summary in its next IRP, including how it considered and incorporated stakeholder input.	Appendix G: Stakeholder Engagement & Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694.
7	The Commission certifies the Resilient Minneapolis Project and limits cost recover to a cost cap of $9 million unless Xcel can show by clear and convincing evidence that the costs were reasonable, prudent, and beyond the Company's control. Xcel shall file reports annually on December 1st through 2026. The first report is due on December 1, 2022 and must contain the following information: a. Define and quantify the emergency service capabilities and capacity in more detail and in more concrete terms than Xcel has hitherto provided in its proposal and via discovery responses. b. Report on the status of the emergency service capacity to ensure that the benefits are or can be realized, and to develop a process and a plan for demonstrating that the benefits can be realized. c. Define a process for identifying and addressing the potential situation in which either or both of the following conditions arise: the project fails to deliver all, or a large portion of Xcel's claimed quantified benefits and/or the claimed unquantified benefits cannot or are unlikely to materialize	Filed 12/1/22 in Docket No. E002/M-21-694.

8	Xcel shall consult with stakeholders, including RMP site partners, on the development of a set of evaluation metrics that allow comparison to other resilience offerings. This set of evaluation metrics shall be included in Xcel's December 1 annual reports. Xcel shall provide the following information and data to the greatest extent practicable. Where the Company is not able to do so, it shall explain why. Where applicable, Xcel must include data in spreadsheet (.xlsc) format. In consultation with stakeholders Xcel shall consider the following reporting elements when developing evaluation metrics:	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.a	Xcel shall include optional feedback from site hosts and community partners, using a form Xcel distributes on an annual (or more frequent) basis, which invites partners to discuss their experience participating in the project, its impact on the organization or community, or other information partners wish to share with the Commission.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.b	Xcel shall file a spreadsheet reporting, for each RMP site, the number of union labor jobs or contracts and the number of contracts awarded to women- and minority-owned businesses.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.c	Xcel shall file a spreadsheet reporting, for each RMP site, the number of workers trained in the operation of energy systems and the number of energy-related jobs created	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.d	Xcel shall record in a spreadsheet any instances of natural events or Company-orchestrated simulations in which RMP systems switch to "islanded mode" and how the system performs	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.e	Xcel shall track in a spreadsheet or in narrative form how RMP sites' rooftop solar, BESS, and microgrid are dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.f	Xcel shall report in a spreadsheet, for any of the RMP site, when a generator is used, for how long, and the generator power capacity and fuel source.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.g	Xcel shall quantify in a spreadsheet the number and type of HVAC upgrades, building envelope upgrades, energy efficiency measures, and/or demand response program undertaken at any of the RMP sites, shared at the discretion of RMP site hosts and partners	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.h	Xcel shall develop metrics related to resiliency benefits and energy equity and data collection on those topics	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
9	Xcel shall file a letter in this docket to notify the Commission and stakeholders if the Company encounters any significant procurement challenges related to RMP, including delays, low bid numbers, or unexpected costs	See April 19 and June 9, 2023 filings in Docket No. E002/M-21-694.

10	Xcel shall include a discussion of the RMP in comparison to battery and microgrid programs/projects in Xcel's service territories in other states, lessons learned form these programs as they move through construction and into operation, and specific details how these lessons are informing RMP project decisions, reducing costs, and/or improving efficacy a. Xcel shall include this information in Xcel's 2023 IDP filing b. Xcel shall include this information in each of Xcel's annual reports filed in Docket No. E-002/M-21-694	Appendix B3: Existing and Potential New Grid Modernization Pilots
11	Xcel shall report on the Resilient Minneapolis Project in its quarterly reports in Docket No. E,G-999/M-20-492	See Docket No. E,G999/M-20-492
Order Pt.	**MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694)**	**Location**
3	Allows utilities to file EV data in future IDP Plans that align with the data filed in their Annual Program Electric Vehicle reports (due June 1 of each year)	Appendix H: Transportation Electrification Plan
Order Pt.	**MPUC IRP Requirement (4/15/22 Order in Docket No. E002/RP-19-368)**	**Location**
9	Xcel shall takes steps to better align distribution and resouce planning, including: A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan. B. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. C. Proactively plan investments in hosting capacity and other necessary system capactiy to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources. D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs. E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	See corresponding IDP Requirement 3.A.5. Appendix A1: System Planning Appendix F: Non-Wires Alternatives Analysis
Page #	**Docket No. 16-521, Staff Briefing Papers for the May 20, 2021 Commission Meeting**	**Location**
22	Already, the Commission has seen crossover with the DGWG and IDPs, hosting capacity analysis, grid modernization investments, and more. As mentioned, the rate-regulated utilities will discuss anticipated impacts of the FERC Orders in their IDPs to be filed November 1, 2021. Staff anticipates more robust discussion of these issues in the 2021 IDPs.	Appendix E: System Interconnection and Distributed Energy Resources
Order Pt.	**MN Electric Rate Case Requirements (Order 7/23/23 in Docket No. 21-630)**	**Location**
27.b	Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR’s reliability results in its Integrated Distribution System Plan.	Appendix B1: Grid Modernization Appendix D: Distribution Financial Information

29	In its next Integrated Distribution Plan, Xcel must propose and discuss ways for the IDP Process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP	Executive Summary
31	Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.	Appendix D: Distribution Financial Information
33	The Commission rejects Xcel's proposal for the Distributed Intelligence program without the prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement	Appendix J: Distributed Intelligence
36	Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.	Appendix B1: Grid Modernization
133	Xcel shall, in its next Integrated Distribution plan ("IDP), quantify the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments	Appendix C: Action Plans
Order Pt.	**TCR (Order 6/28/23 in Docket No. 21-814)**	**Location**
17	Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing: a. HAN, AMI, and AMI-DI specifications and related customer data access policies. b. Bring-your-own device HAN requirements and terms c. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN. d. Methods to provide customers equal access to the level of data available to the utility. e. A summary of industry customer data access standards	Appendix J: Distributed Intelligence
Order Pt.	**IRA (Order 9/12/23 in Docket No. CI-22-624)**	**Location**
1	The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how […] the Act has impacted planning assumptions including (but not limited to) […] the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.	Appendix D: Distribution Financial Information

Correlation of IDP Content to Commission's IDP Planning Objectives

The Commission's Integrated Distribution Planning Requirements for Xcel Energy state:

> *Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including:*
> 1. *An analysis of how the information presented in the IDP related to each Planning Objective,*
> 2. *The location in the IDP,*
> 3. *Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and*
> 4. *Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.*

The Commission's Planning Objectives state:

> *The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans 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 and services, with opportunities for adoption of new distributed technologies;*
> 4. *Ensure optimized use of electricity grid assets and resources to minimize total system costs; and*
> 5. *Provide the Commission with the information necessary to understand Xcel'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.*

We have followed the format the Department used in their February 22, 2019 Comments in Docket No. E002/CI-18-251 (as well as our 2019 and 2021 IDP filings) in complying with the Commission's requirement.

A. Planning Objective #1

The first planning objective of the IDP is:

> *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.*

We provide a high-level analysis of the location of these topics in the IDP in Table 1 below. In response to feedback received in our 2021 IDP, we have attempted to be more judicious in identifying the locations in our 2023 IDP where we discuss these topics.

Table 1: Location of Topics of the First Planning Objective in the IDP

Topic	IDP Location – Significant Discussion	IDP Location – Additional or Related Discussion
Safety	Appendix A2 – Standards, Asset Health, and Reliability Management Appendix A3 – Distribution Operations Appendix E – Distributed Energy Resources, System Interconnection, and Hosting Capacity	Integrated Distribution Plan Appendix A1 – System Planning Appendix B2 – Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies Appendix D – Distribution Financial Framework and Information
Security	Appendix B2 – Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies Appendix E – Distributed Energy Resources, System Interconnection, and Hosting Capacity	Integrated Distribution Plan Appendix A1 – System Planning Appendix A3 – Distribution Operations Appendix D – Distribution Financial Framework and Information
Reliability	Integrated Distribution Plan Appendix A1 – System Planning Appendix A2 – Standards, Asset Health, and Reliability Management Appendix A3 – Distribution Operations Appendix B1 – Grid Modernization Appendix D – Distribution Financial Framework and Information	Appendix C – Action Plans Appendix E – Distributed Energy Resources, System Interconnection, and Hosting Capacity Appendix F – Non-Wires Alternatives Analysis
Resilience	Integrated Distribution Plan Appendix A2 – Standards, Health, and Reliability Management Appendix A3 – Distribution Operations Appendix B1 – Grid Modernization Appendix B3 – Existing and Potential New Grid Modernization Pilots	Appendix A1 – System Planning Appendix C – Action Plans
Fair and	Integrated Distribution Plan	Appendix A3 – Distribution Operations

Topic	IDP Location – Significant Discussion	IDP Location – Additional or Related Discussion
Reasonable Costs	Appendix A1 – System Planning Appendix B1 – Grid Modernization Appendix C – Action Plans Appendix D – Distribution Financial Framework and Information Appendix E – Distributed Energy Resources, System Interconnection, and Hosting Capacity Appendix F – Non-Wires Alternatives Analysis Appendix I – Distribution System Upgrades	Appendix C – Action Plans Appendix H – Transportation Electrification Plan
Consistent with State Energy Policies	Integrated Distribution Plan Appendix A1 – System Planning Appendix B1 – Grid Modernization Appendix B2 – Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies Appendix B3 – Existing and Potential New Grid Modernization Pilots Appendix E – Distributed Energy Resources, System Interconnection, and Hosting Capacity Appendix F – Non-Wires Alternatives Analysis Appendix H – Transportation Electrification Plan Appendix I – Distribution System Upgrades	Appendix A2 – Standards, Asset Health, and Reliability Management Appendix C – Action Plans Appendix D – Distribution Financial Framework and Information Appendix G – Stakeholder Engagement

As suggested by the table above, the topics of the first planning objective are central to the planning and operation of the distribution grid, and the Company has addressed each of the topics broadly and substantively.

B. Planning Objective #2

The second planning objective of the IDP is to enable greater customer engagement, empowerment, and options for energy services.

In support of this planning objective, we discuss our customer strategy in Appendix B1 (Grid Modernization). Appendix J (Distributed Intelligence) provides information on new tools to enable greater customer engagement, empowerment, and options.

The Company offers and is continuing to develop options for customers to pursue transportation electrification and offers advisory services to educate and inform the public of these options and of the benefit of driving electric. We discuss these efforts in Appendix H (Transportation Electrification Plan)

There are also related discussions in Appendix B1 (Grid Modernization) when discussing our plans for Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), and Advanced Distribution Management System (ADMS), each of which are technological innovations that are geared toward fulfilling the second planning objective.

Extensive discussions in Appendix E (Distributed Energy Resources) and Appendix B3 (Grid Modernization Pilots) also support the Commission's second planning objective.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the second planning objective. However, this does represent that we provided extensive information and discussion of items related to the second planning objective.

C. Planning Objective #3

The third planning objective of the IDP is designed to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Much of the information and discussion provided in the IDP related to the second planning objective are also applicable to the third planning objective. Specific to the adoption of new distributed technologies, we provide extensive discussion of our DER roadmap in Appendix E (Distributed Energy Resources) and Appendix A1 (System Planning). Our discussion of our grid modernization investments – AMI, FAN, FLISR, and ADMS – provides information and discussion relevant to the third planning objective. These are discussed throughout the filing but particularly in Appendix B1 (Grid Modernization).

Grid-facing platforms and tools also relate to the third planning objective. such as LoadSEER, Distributed Energy Resources Management System (DERMS), and Distributed Intelligence (DI) are discussed throughout the IDP, most notably in

Appendix A1 (System Planning), Appendix B1 (Grid Modernization), Appendix E (Distributed Energy Resources), and Appendix J (Distributed Intelligence).

Appendix B3 (Grid Modernization Pilots) also relates to the third planning objective. Specifically, we provide information on load flexibility and EV pilots and demonstration projects, as well as a residential battery demand response pilot, rate pilots, and potential new pilots. Each of these pilots supports the third planning objective as they provide potential new platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Finally, Appendix H (Transportation Electrification Plan) also includes information related to the third planning objective. Much like Appendix B3, it includes information about our EV-related load flexibility efforts as well as our existing EV offerings and discussion of potential new offerings. These discussions highlight the new products and services we are providing to customers in order to enable customers to pursue electrified transportation while encouraging off-peak charging.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the third planning objective. However, this does represent that we provided extensive information and discussion of items related to the third planning objective.

D. Planning Objective #4

The fourth planning objective of the IDP is designed to ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In the IDP, we discuss our efforts toward integrated planning in Appendix A1 (System Planning), which supports the fourth planning objective.

In the context of the Company's planning efforts related to distributed energy resources (DER), we also provide Appendix E (Distributed Energy Resources) and Appendix I (Distribution System Upgrades).

Our EV-related programs, pilots, and demonstrations are generally designed to encourage off-peak charging, allowing additional load that can more greatly utilize overnight wind production and avoid creating additional stress on the system during system peaks. We discuss these programs in Appendix H (Transportation Electrification Plan).

The investments that we are currently making in asset health and reliability management, discussed in Appendix A2, and grid modernization, such as ADMS, AMI, FAN, and FLISR help to lay the foundation for continued resiliency and reliability, and will allow us to respond to increased DER penetration. These are discussed throughout the filing but particularly in Appendix B1 (Grid Modernization).

Again, we note that this list is not exhaustive of the items discussed in the IDP that relate to the fourth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fourth planning objective.

E. Planning Objective #5

Finally, and as noted above, the fifth planning objective of the IDP is to provide the Commission with the information necessary to understand the Company's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of customer cost and value.

The IDP provides a comprehensive discussion about our short-term and long-term distribution system plans and investments, as well as how we plan the system and develop budgets, within Appendix A1 (System Planning), Appendix A2 (Standards, Health, and Reliability Management), Appendix B1 (Grid Modernization), and Appendix D (Distribution Financial Information).

First, we note that we already conduct a robust CBA/risk analysis for capacity projects, as discussed in *Appendix A1: System Planning* and *Attachment D: Risk Scoring Methodology*. This risk scoring methodology helps prioritize capacity projects based on the reliability and financial benefits of the projects compared to the costs. While we have called it a risk analysis, it is a CBA.

With regard to the costs and benefits of specific investments, we discuss our robust CBA/risk analysis for capacity projects, as discussed in Appendix A1 (System Planning) and Attachment D (Risk Scoring Methodology). In addition, we provide Appendix F (Non-Wires Alternatives Analysis), which provides the analyses we performed to evaluate non-traditional distribution system solutions to our traditional distribution solutions.

With regard to customer value, in Appendix B1 (Grid Modernization), we discuss the overall customer strategy and benefits of our grid modernization strategy. We also provide the impacts to net present value of system cost in Attachment G (Distribution Function NPV).

We note that this list is not exhaustive of the items discussed in the IDP that relate to the fifth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fifth planning objective.

F. IDP Filing Requirement Refinements

Finally, with respect to the last discussion point requesting the Company provide suggestions as to any refinements to the IDP filing requirements that would enhance the Company's ability to meet the Planning Objectives, we suggest that the IDP-specific financial categories be eliminated, as outlined in the IDP Main Report. The manual process required to recategorize our five-year investment plan into IDP financial categories creates risk of errors, limits the ability of parties and the Commission to compare financial information across dockets, and ultimately distracts from the core Planning Objectives. Please see the IDP Main Report for suggested redlines to the IDP Requirements.

The IDP is a robust report and a significant undertaking by the Company. The filing requirements have grown over time, particularly over the past year. We are open to iterating on the IDP process and filing requirements in support of the Commission's Planning Objectives, but we respectfully suggest that any recommendations for additional filing requirements be closely scrutinized for alignment with Planning Objectives and to ensure that compiling and reviewing the IDP does not become overly burdensome for the Company or parties.

I. RISK SCORING METHODOLOGY

As part of our risk analysis and mitigation processes, discussed as part of our annual System Planning process, Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment and may also enter the benefit and any associated service quality metric impacts (i.e., customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects run through the risk model for scoring. This process involves various steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g., taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, capacity, demand growth, and annual hours at risk). It is also based on contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, annual hours at risk, and yearly failure rate of equipment at risk), and the number of customer complaints to the public utilities commission.
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., $1.52/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are applied to the financial benefit and reliability benefit.
- A benefit : cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

Part II reflects all Distribution projects budgeted in the latest/most current available budget (July 2023) at the time of our IDP filing. Budgets are formally updated annually and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

Capacity is the only IDP category for which Risk Scores are applicable because it is the only category where we can objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in the system planning Appendix, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates*. Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and a portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.

- *New Business*. Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and a portion may additionally be emergent in the current budget year.

- *Asset Health*. Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the long-term value that a programmatic approach to asset health provides.

- *Blankets*. Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.

- *Programs*. Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the long-term value that a programmatic engineering approach to cable failures provides.

Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

PROTECTED DATA SHADED

II. CAPACITY RANKINGS

Mitigation No.	Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs ($M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit	Financial Benefit	Total Weighted Benefit	Project Score
					[PROTECTED DATA BEGINS					
E154.022744	Install Glenwood GLD Feeder	NSPM - ED	40	$0.092	208,989	1,194	0.318	0.001	0.3189	**3.5**
E144.018971	Reinforce Veseli VES TR1	NSPM - ED	40	$0.148	267,871	1,768	0.407	0.002	0.4089	**2.8**
E154.021667	Install Feeder Tie SDX312-FSL311	NSPM - ED	40	$0.010	365,059	849	0.555	0.001	0.5557	**56.7**
E143.024059	Load Transfer WIL089 to WIL092	NSPM - ED	35	$0.001	42,244	114	0.064	0.000	0.0643	**47.6**
E151.023981	Reinforce Merriam Park MPK063	NSPM - ED	35	$0.075	2,334,146	6,293	3.548	0.006	3.5542	**47.2**
E154.022738	Install Dayton Area Sub	NSPM - ED	40	$0.651	8,996,669	25,409	13.675	0.025	13.7003	**21.0**
E143.024051	Reinforce East Bloomington EBL062	NSPM - ED	40	$0.062	550,247	1,577	0.836	0.002	0.8380	**13.5**
E154.010157	Install Albany ALB TR	NSPM - ED	40	$0.013	100,897	303	0.153	0.000	0.1537	**11.8**
E150.023946	Reinforce Lone Oak LOK062	NSPM - ED	35	$0.008	53,962	232	0.082	0.000	0.0823	**10.7**
E150.022038	Install Stockyards STY TR03	NSPM - ED	40	$0.514	3,505,156	11,467	5.328	0.011	5.3393	**10.4**
E151.023993	Reinforce Merriam Park MPK068	NSPM - ED	40	$0.039	229,945	742	0.350	0.001	0.3503	**8.9**
E151.023992	Reinforce Merriam Park MPK067	NSPM - ED	40	$0.039	226,869	736	0.345	0.001	0.3456	**8.8**
E151.024029	Reinforce Western WES061 and WES075	NSPM - ED	35	$0.038	185,374	969	0.282	0.001	0.2827	**7.3**
E147.024028	Reinforce Parkers Lake PKL085	NSPM - ED	40	$0.010	32,923	133	0.050	0.000	0.0502	**5.1**
E151.024040	Reinforce Western WES062 Feeder	NSPM - ED	40	$0.013	36,161	157	0.055	0.000	0.0551	**4.4**
E151.023986	Reinforce Merriam Park MPK061	NSPM - ED	40	$0.108	308,833	1,344	0.469	0.001	0.4708	**4.4**
E143.022795	Extend Hyland Lake HYL074	NSPM - ED	40	$0.060	167,656	742	0.255	0.001	0.2556	**4.2**
E150.023935	Install Feeder Tie RMT322-RMT311	NSPM - ED	35	$0.090	243,895	1,842	0.371	0.002	0.3726	**4.1**
E144.024046	Reinforce Wabasha WAB021	NSPM - ED	35	$0.014	36,614	282	0.056	0.000	0.0559	**4.1**
E151.024041	Reinforce Western WES074 Feeder	NSPM - ED	35	$0.024	54,813	468	0.083	0.000	0.0838	**3.5**

PROTECTED DATA SHADED

E141.019928	Extend Saint Louis Park SLP092	NSPM - ED	40	$0.059	133,885	659	0.204	0.001	0.2042	**3.5**
E144.015692	Install Summit Avenue SMT TR3	NSPM - ED	40	$0.302	680,358	4,283	1.034	0.004	1.0384	**3.4**
E144.020614	Reinforce Faribault FAB TR2	NSPM - ED	40	$0.231	475,272	3,213	0.722	0.003	0.7256	**3.1**
E147.016682	Reinforce TWL079 and TWL081	NSPM - ED	40	$0.359	735,266	3,847	1.118	0.004	1.1215	**3.1**
E144.000791	Install La Crescent Area Sub	NSPM - ED	40	$0.438	805,061	5,170	1.224	0.005	1.2289	**2.8**
E151.024008	Reinforce Merriam Park MPK087	NSPM - ED	35	$0.110	169,291	1,966	0.257	0.002	0.2593	**2.4**
E147.022783	Reinforce All Osseo OSS Feeders	NSPM - ED	40	$0.526	770,898	5,778	1.172	0.006	1.1775	**2.2**
E156.011874	Install Birch Area Sub	NSPM - ED	40	$0.642	586,947	7,354	0.892	0.007	0.8995	**1.4**
E147.014487	Upgrade TWL061 feeder capacity	NSPM - ED	40	$0.119	104,085	971	0.158	0.001	0.1592	**1.3**
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	NSPM - ED	40	$0.016	13,720	159	0.021	0.000	0.0210	**1.3**
E154.022828	C Install Blue Heron TR2	NSPM - ED	40	$0.359	280,064	4,027	0.426	0.004	0.4297	**1.2**
E141.024063	Install Midtown MDT064 Feeder	NSPM - ED	40	$0.227	143,892	1,737	0.219	0.002	0.2205	**1.0**
E152.024015	Install Tracy Area Substation	NSPM - ED	90	$0.505	245,263	0	0.373	0.000	0.3728	**0.7**
E144.024031	Convert Gaylord GAY 4kV	NSPM - ED	40	$0.397	15,184	3,788	0.023	0.004	0.0269	**0.1**
E150.022858	Install Inver Hills IVH TRs	NSPM - ED	40	$0.837	19,568	8,102	0.030	0.008	0.0378	**0.0**
E143.022794	Install Wilson Feeder WIL064	NSPM - ED	40	$0.104	1,952,574	4,862	2.968	0.005	2.9728	**28.6**
E156.011061	Install Wyoming WYO Feeder	NSPM - ED	40	$0.134	193,032	1,461	0.293	0.001	0.2949	**2.2**
E144.024037	Install West Byron WEB TR2	NSPM - ED	35	$0.338	425,271	6,426	0.646	0.006	0.6528	**1.9**
E150.023962	Reinforce Hastings HAS022	NSPM - ED	35	$0.027	29,238	456	0.044	0.000	0.0449	**1.7**
E154.024024	Extend Avon Feeder AVN021	NSPM - ED	35	$0.142	148,254	2,431	0.225	0.002	0.2278	**1.6**
E151.024013	Reinforce Merriam Park MPK085	NSPM - ED	35	$0.059	60,034	990	0.091	0.001	0.0922	**1.6**
E156.011752	Install Lindstrom LIN Feeder	NSPM - ED	40	$0.056	51,803	480	0.079	0.000	0.0792	**1.4**
E142.024045	Install Dahlgren DHL062 Feeder	NSPM - ED	35	$0.095	83,902	1,565	0.128	0.002	0.1291	**1.4**
E141.024065	Reinforce Medicine Lake MEL073	NSPM - ED	40	$0.065	51,270	522	0.078	0.001	0.0785	**1.2**
E144.024038	Reinf West Faribault WEF TR7	NSPM - ED	35	$0.115	87,120	2,054	0.132	0.002	0.1345	**1.2**
E151.024039	Reinforce WES065 and WES076	NSPM - ED	40	$0.027	19,713	210	0.030	0.000	0.0302	**1.1**
E141.021663	Extend Southtown Feeder SOU069	NSPM - ED	40	$0.023	16,672	180	0.025	0.000	0.0255	**1.1**

PROTECTED DATA SHADED

E150.023953	Reinforce Rogers Lake RLK073	NSPM - ED	40	$0.042	29,771	331	0.045	0.000	0.0456	**1.1**
E144.008708	Install Cannon Falls CAF TR2	NSPM - ED	40	$0.151	86,825	1,402	0.132	0.001	0.1334	**0.9**
E150.023955	Reinforce Rogers Lake RLK071	NSPM - ED	40	$0.058	28,230	427	0.043	0.000	0.0433	**0.7**
E141.019956	Reinforce Terminal TER073	NSPM - ED	40	$0.072	33,925	525	0.052	0.001	0.0521	**0.7**
E143.019054	Reinforce Edina EDA062	NSPM - ED	40	$0.033	14,971	238	0.023	0.000	0.0230	**0.7**
E144.010920	Reinforce Burnside BUR TR2	NSPM - ED	40	$0.277	117,494	3,351	0.179	0.003	0.1819	**0.7**
E144.010889	Reinforce Pine Island TR1	NSPM - ED	40	$0.154	65,207	1,381	0.099	0.001	0.1005	**0.7**
E143.017702	Install Viking VKG Feeder	NSPM - ED	40	$0.274	86,208	1,911	0.131	0.002	0.1329	**0.5**
E144.013622	Convert Lafayette LAF 4kV	NSPM - ED	40	$0.126	3,764	27,986	0.006	0.028	0.0337	**0.3**
E142.011721	Install Orono ORO TR2 & Feeder	NSPM - ED	40	$0.255	36,952	2,549	0.056	0.003	0.0587	**0.2**
E154.022742	Reinforce Meire Grove TR1	NSPM - ED	40	$0.105	983	845	0.001	0.001	0.0023	**0.0**
E141.024064	Extend Elliot Park Feeder ELP082	NSPM - ED	40	$0.020	8,500	146	0.013	0.000	0.0131	**0.6**
E144.000793	Install Zumbrota ZUM TR	NSPM - ED	40	$0.188	52,089	1,625	0.079	0.002	0.0808	**0.4**
E144.024034	Reinforce Waterville TR3	NSPM - ED	35	$0.217	49,681	3,625	0.076	0.004	0.0791	**0.4**
E150.022735	Install Lone Oak LOK Feeder	NSPM - ED	35	$0.458	89,220	7,515	0.136	0.008	0.1431	**0.3**
E156.007927	Install Goose Lake GLK TR3	NSPM - ED	40	$0.268	14,499	45,196	0.022	0.045	0.0672	**0.3**
E150.023959	Reinforce Afton AFT321	NSPM - ED	40	$0.492	75,798	4,167	0.115	0.004	0.1194	**0.2**
E156.015811	Reinforce Oakdale OAD073 & OAD075	NSPM - ED	40	$0.017	2,232	141	0.003	0.000	0.0035	**0.2**
E156.010177	Install Kohlman Lake KOL Feeder	NSPM - ED	40	$0.295	1,504	1,933	0.002	0.002	0.0042	**0.0**
E142.013437	Install Excelsior EXC TR2	NSPM - ED	40	$0.225	249	2,189	0.000	0.002	0.0026	**0.0**
E144.002712	Install Goodview GVW Feeder	NSPM - ED	40	$0.118	1,674,752	4,378	2.546	0.004	2.5500	**21.7**
E150.023945	Reinforce Lone Oak LOK082 & LOK093	NSPM - ED	35	$0.078	25,573	1,191	0.039	0.001	0.0401	**0.5**
E151.023988	Reinforce Merriam Park MPK081	NSPM - ED	40	$0.106	29,360	732	0.045	0.001	0.0454	**0.4**
E141.024066	Reinforce Medicine Lake MEL089	NSPM - ED	40	$0.141	34,676	963	0.053	0.001	0.0537	**0.4**
E141.020729	Reinforce Saint Louis Park SLP092	NSPM - ED	40	$0.265	56,411	1,787	0.086	0.002	0.0875	**0.3**
E143.024049	Extend East Bloomington EBL066	NSPM - ED	40	$0.036	7,357	242	0.011	0.000	0.0114	**0.3**
E151.023987	Reinforce Merriam Park MPK072	NSPM - ED	40	$0.106	21,123	714	0.032	0.001	0.0328	**0.3**

PROTECTED DATA SHADED

E141.019958	Reinforce Moore Lake MOL071	NSPM - ED	40	$0.036	6,925	241	0.011	0.000	0.0108	**0.3**
E141.022787	Reinforce SLP85 Feeder	NSPM - ED	40	$0.177	26,621	1,172	0.040	0.001	0.0416	**0.2**
E151.024018	Reinforce Upper Levee UPP081	NSPM - ED	35	$0.071	7,953	1,040	0.012	0.001	0.0131	**0.2**
E150.021672	Install Chemolite CHE TR03	NSPM - ED	40	$0.391	36,647	2,541	0.056	0.003	0.0582	**0.1**
E142.024044	Install Gleason Lake GSL343	NSPM - ED	40	$0.110	9,325	713	0.014	0.001	0.0149	**0.1**
E156.013545	Expand AHI substation	NSPM - ED	40	$0.644	33,052	5,262	0.050	0.005	0.0555	**0.1**
E144.010884	Install Belle Plaine Area Sub	NSPM - ED	40	$0.480	23,815	3,871	0.036	0.004	0.0401	**0.1**
E151.000726	Install Prior PRR TR2	NSPM - ED	40	$0.453	0	31,024	0.000	0.031	0.0310	**0.1**
E154.018960	Reinforce Glenwood GLD Sub Equip	NSPM - ED	40	$0.043	1,252	350	0.002	0.000	0.0023	**0.1**
E147.013374	Reinforce Elm Creek TR1 to 50 MVA	NSPM - ED	40	$0.148	3,415	1,198	0.005	0.001	0.0064	**0.0**
E147.013373	Reinforce Basset Creek BCR TR1	NSPM - ED	40	$0.148	3,409	1,198	0.005	0.001	0.0064	**0.0**
E150.022709	Install Williams Brothers TR4	NSPM - ED	35	$0.364	3,631	5,815	0.006	0.006	0.0113	**0.0**
E144.023176	Install Sibley Park SIP TR03	NSPM - ED	40	$0.219	1,965	1,765	0.003	0.002	0.0048	**0.0**
E146.024017	Install Averill AVR TR02	NSPM - ED	40	$0.148	1,309	1,193	0.002	0.001	0.0032	**0.0**
E147.013379	Install West Coon Rapids WCR TR	NSPM - ED	40	$0.329	2,361	2,659	0.004	0.003	0.0062	**0.0**
E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	NSPM - ED	40	$0.354	2,140	2,855	0.003	0.003	0.0061	**0.0**
E147.015683	Install Osseo OSS TR3	NSPM - ED	40	$0.569	1,527	4,592	0.002	0.005	0.0069	**0.0**
E150.024167	Install Lone Oak LOK TR3	NSPM - ED	38	$0.242	1	2,674	0.000	0.003	0.0027	**0.0**
E150.022705	Reinforce West Hastings WEH TR1	NSPM - ED	40	$0.385	612	3,100	0.001	0.003	0.0040	**0.0**
E150.013326	Install West Hastings WEH TR2	NSPM - ED	40	$0.403	134	3,248	0.000	0.003	0.0035	**0.0**
E151.023984	Reinforce Daytons Bluff DBL067	NSPM - ED	40	$0.078	6,517	508	0.010	0.001	0.0104	**0.1**
E150.020608	Install Red Rock RRK073	NSPM - ED	40	$0.175	8,473	1,163	0.013	0.001	0.0140	**0.1**
E156.011764	Reinforce Tanners Lake TLK Sub Equip	NSPM - ED	40	$0.013	334	86	0.001	0.000	0.0006	**0.0**
E141.019925	SUBS Reinforce Gopher TR1	NSPM - ED	40	$0.020	128	128	0.000	0.000	0.0003	**0.0**
E141.024119	Reinforce Elliot Park ELP071 Feeder	NSPM - ED	35	$0.036	0	518	0.000	0.001	0.0005	**0.0**
E141.024067	Install New Midtown MDT072	NSPM - ED	40	$0.348	1,478	2,191	0.002	0.002	0.0044	**0.0**

PROTECTED DATA SHADED

E147.024227	Load Trnsfr CRL033 CRL027 CRL031	NSPM - ED	40	$0.020	10	123	0.000	0.000	0.0001	**0.0**
E147.024221	Reinforce Brooklyn Park BRP072	NSPM - ED	40	$0.033	6	206	0.000	0.000	0.0002	**0.0**
E147.024026	Reinforce Twin Lakes TWL068	NSPM - ED	40	$0.049	7	308	0.000	0.000	0.0003	**0.0**
E147.024025	Reinforce Twin Lakes TWL065	NSPM - ED	40	$0.163	8	1,028	0.000	0.001	0.0010	**0.0**
E147.024033	Reinforce Parkers Lake PKL065	NSPM - ED	40	$0.242	7	1,522	0.000	0.002	0.0015	**0.0**
E147.024193	Reinforce Twin Lakes TWL078	NSPM - ED	40	$0.229	5	1,439	0.000	0.001	0.0014	**0.0**
E151.012409	Install Western WES TR3 & Feeders	NSPM - ED	40	$0.444	0	2,796	0.000	0.003	0.0028	**0.0**
E141.021648	Reinforce Elliot Park ELP081	NSPM - ED	40	$0.026	5,101	175	0.008	0.000	0.0079	**0.3**
E143.022265	Install Hyland Lake HYL TR01	NSPM - ED	40	$0.266	1,201	2,148	0.002	0.002	0.0040	**0.0**
									PROTECTED DATA ENDS]	

III. Mitigation Calculation Examples

A. Contingency (N-1) Inputs

[PROTECTED DATA BEGINS

Mitigation Number	Workbook System Risk Number	Peak Load MVA	Available Relief	Customers per MVA	Peak Day Hours Out	Time to Restore (Hours)	Annual Hours at Risk	Failure Rate	Calculated Contingency CMO Prior to Annual Hour at Risk	Annual Hour with Seasonality	Final CMO's
E151.024013	2010.0329	11.08	6.85	164	19.1	12	641	1.16	230,551	0.25	57,638
E151.024013	2022.0299	9.11	7.53	164	11.95	12	67	0.619	28,751	0.083333	2,396
Total for E151.024013											**60,034**
E156.011061	2010.0166	9.62	3.12	120	23.385	12	2500	0.639	174,833	0.583333	101,986
E156.011061	2004.1266	7.24	4.97	120	15.95	12	359	0.078	5,083	0.166667	847
E156.011061	2006.0229	7.54	5.14	120	16.4	12	394	0.552	39,108	0.166667	6,518
E156.011061	2005.072	9.59	4.02	120	22.615	12	1916	0.737	167,106	0.5	83,553
E156.011061	2011.0158	7.44	7	120	6.7	12	8	0.289	1,534	0.083333	128
Total for E156.011061											**193,032**

PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS

Hrs at Risk = Effective Months	Effective Months – Trans. Seasonally
304	1
643	2
873	3
1,295	4
1,720	5
2,100	6
2,735	7
3,292	8
3,881	9
4,496	10
5,677	11
7,264	12

PROTECTED DATA ENDS]

B. Overload (N-0) Inputs

[PROTECTED DATA BEGINS

Overload (N-0)								Calculated CMO's			
Mitigation Number		Annual Hours at Risk	MVA Beyond Threshold	Customer Per MVA	Demand Growth (%)	Current Capacity - MVA	Threshold	Year 1	Year 2	Year 3	Average of 3 years of Growth - CMO's
E143.024059	2023.0866	13	0.85	120	0.5%	9.7	100%	39,874	42,343	44,824	42,347
Total for E143.024059								39,874	42,343	44,824	**42,347**
E150.023962	2022.0308	8	0.69	164	0.5%	10.3	100%	27,158	29,321	31,495	29,325
Total for E150.023962								27,158	29,321	31,495	**29,325**

PROTECTED DATA ENDS]

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2024 Forecasted Demand kVA	2024 Forecasted Capacity kVA	2024 Forecasted Percent Loading	Planned Spending in 5 Year Budget
				[PROTECTED DATA BEGINS					
E141.019925	SUBS Reinforce Gopher TR1	2019.0541	1	GPH_TR2	0.02	32,119	51,054	63%	$ 300,000
E141.019928	Extend Saint Louis Park SLP092	2017.0157	1	SLP092	1000.00	9,230	10,192	91%	$ 900,000
E141.019956	Reinforce Terminal TER073	2020.0340	1	TER083	0.72	7,436	9,695	77%	$ 1,100,000
E141.019958	Reinforce Moore Lake MOL071	2020.0351	1	MOL061	0.30	8,805	11,311	78%	$ 550,000
E141.020729	Reinforce Saint Louis Park SLP092	2020.0300	1	SLP086	0.33	7,803	10,565	74%	$ 4,050,000
E141.021648	Reinforce Elliot Park ELP081	2020.0239	1	ELP084	0.80	9,378	8,576	109%	$ 400,000
E141.021663	Extend Southtown Feeder SOU069	2020.0309	1	SOU069	1.12	5,708	14,045	41%	$ 350,000
E141.022787	Reinforce SLP85 Feeder	2020.0305	1	SLP097	0.24	8,483	10,192	83%	$ 2,710,000
E141.024063	Install Midtown MDT064	2023.0817	0	ALD083	1000.00	11,817	10,590	112%	$ 3,470,000
E141.024064	Extend Elliot Park Feeder ELP082	2020.0238	1	ELP082	0.65	11,105	9,943	112%	$ 310,000
E141.024065	Reinforce Medicine Lake MEL073	2020.0558	0	MEL073	1.20	8,987	8,203	110%	$ 1,000,000
E141.024066	Reinforce Medicine Lake MEL089	2016.0513	0	MEL089	0.38	8,893	8,203	108%	$ 2,160,000
E141.024067	Install Midtown MDT072 Feeder	2021.0451	0	ALD072	0.01	8,216	7,607	108%	$ 5,320,000
E141.024119	Reinforce Elliot Park ELP071 Feeder	2023.0822	0	ELP071	0.01	7,657	7,706	99%	$ 530,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0539	1	ORO_TR1	0.22	18,275	30,409	60%	$ 4,100,000
E142.013437	Install Excelsior EXC TR2	2005.0538	1	EXC_TR1	0.01	13,229	20,951	63%	$ 3,900,000
E142.024044	Install Gleason Lake GSL343	2023.0854	1	GSL342	0.14	30,111	34,802	87%	$ 1,685,000
E142.024045	Install Dahlgren DHL062	2014.0473	1	DHL061	1.35	7,199	13,921	52%	$ 1,410,000
E143.017702	Install Viking VKG Feeder	2016.0418	1	WSG076	0.52	6,267	13,921	45%	$ 4,195,000
E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	2017.0447	1	BLL_TR1	0.02	15,326	27,866	55%	$ 5,747,000
E143.019054	Reinforce Edina EDA062	2016.0386	1	NMC093	0.70	8,463	12,976	65%	$ 500,000
E143.022265	Install Hyland Lake HYL TR01	2020.0166	1	HYL_TR2	1000.00	30,444	49,753	61%	$ 4,125,000
E143.022794	Install Wilson Feeder WIL064	2016.0402	1	WIL086	28.61	10,088	13,921	72%	$ 1,590,000
E143.022795	Extend Hyland Lake HYL074	2016.0389	1	WIL071	4.23	8,890	9,695	92%	$ 925,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2024 Forecasted Demand kVA	2024 Forecasted Capacity kVA	2024 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E143.024049	Extend East Bloomington EBL066	2018.0905	1	EBL071	0.32	6,358	8,079	79%	$ 550,000
E143.024051	Reinforce East Bloomington EBL062	2023.0264	0	EBL062	13.50	9,032	7,358	123%	$ 950,000
E143.024059	Load Transfer WIL089 to WIL092	2023.0866	0	WIL089	47.57	10,547	9,695	109%	$ 20,000
E144.000791	Install La Crescent Area Sub	2004.1112	1	LAC_TR1	2.71	11,802	16,500	72%	$ 6,650,000
E144.000793	Install Zumbrota ZUM TR	2004.1114	1	ZUM_TR1	0.43	13,535	14,222	95%	$ 3,050,000
E144.002712	Install Goodview GVW Feeder	2004.0808	1	GVW023	22.30	9,016	8,940	101%	$ 1,800,000
E144.008708	Install Cannon Falls CAF TR2	2005.0386	1	CTF_TR1	0.88	12,303	11,588	106%	$ 2,450,000
E144.010884	Install Belle Plaine Area Sub	2004.1288	1	BEL_TR1	0.10	15,499	15,451	100%	$ 6,400,000
E144.010889	Reinforce Pine Island TR1	2007.0715	1	PIL_TR2	0.65	6,803	7,725	88%	$ 2,500,000
E144.010920	Reinforce Burnside BUR TR2	2006.0285	1	BUR_TR1	0.59	9,203	31,375	29%	$ 4,900,000
E144.015692	Install Summit Ave SMT TR3	2016.0175	1	SMT072	1000.00	11,902	13,921	85%	$ 4,100,000
E144.018971	Reinforce Veseli VES TR1	2013.1536	0	EKO021	2.76	4,307	3,953	109%	$ 2,200,000
E144.020614	Reinforce Faribault FAB TR2	2005.0479	1	FAB_TR2	1000.00	11,848	10,000	118%	$ 3,900,000
E144.023176	Install Sibley Park SIP TR03	2018.0092	1	SIP_TR2	0.02	21,175	30,611	69%	$ 3,550,000
E144.024034	Reinforce Waterville TR3	2013.1500	1	WAT_TR3	0.36	3,976	3,863	103%	$ 3,400,000
E144.024037	Install West Byron WEB TR2	2013.0155	0	WEB021	1.93	12,148	9,839	123%	$ 5,300,000
E146.024017	Install Averill AVR TR02	2020.0144	1	AVR_TR1	0.02	11,441	15,451	74%	$ 2,400,000
E147.013373	Reinforce Basset Creek BCR TR1	2013.0595	1	BCR_TR2	0.04	15,621	51,382	30%	$ 2,400,000
E147.013374	Reinforce Elm Creek TR1 to 50 MVA	2012.0530	1	ECK_TR3	0.04	10,470	39,908	26%	$ 2,400,000
E147.013379	Install West Coon Rapids WCR TR	2013.0532	1	WCR_TR3	0.02	21,143	28,684	74%	$ 3,600,000
E147.014487	Reinforce Twin Lakes TWL061	2014.0485	1	TWL065	1000.00	9,745	10,068	97%	$ 1,815,000
E147.015683	Install Osseo OSS TR3	2012.0543	1	OSS_TR1	0.01	45,607	71,709	64%	$ 4,600,000
E147.016682	Reinforce TWL079 and TWL081	2016.0529	1	TWL076	1000.00	9,356	13,921	67%	$ 5,500,000
E147.022783	Reinforce All Osseo OSS Feeders	2012.0534	1	OSS066	1000.00	8,265	9,471	87%	$ 8,300,000
E147.024025	Reinforce Twin Lakes TWL065	2023.0451	0	TWL065	0.01	9,745	10,068	97%	$ 2,500,000
E147.024026	Reinforce Twin Lakes TWL068	2023.0453	0	TWL068	0.01	8,853	9,471	93%	$ 750,000
E147.024028	Reinforce Parkers Lake PKL085	2022.0485	0	PKL085	5.12	10,846	10,565	103%	$ 150,000
E147.024033	Reinforce Parkers Lake PKL065	2023.0374	0	PKL065	0.01	9,770	10,391	94%	$ 3,700,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2024 Forecasted Demand kVA	2024 Forecasted Capacity kVA	2024 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.024193	Reinforce Twin Lakes TWL078	2023.0456	0	TWL078	0.01	8,325	9,198	91%	$ 3,500,000
E147.024221	Reinforce Brooklyn Park BRP072	2023.0224	0	BRP072	0.01	9,466	10,441	91%	$ 500,000
E147.024227	Load Trnsfr CRL033 CRL027 CRL031	2023.0252	0	CRL033	0.01	12,036	10,782	112%	$ 300,000
E150.013326	Install West Hastings WEH TR2	2008.2304	1	WEH_TR1	0.01	11,604	25,982	45%	$ 6,048,000
E150.020608	Install Red Rock RRK073	2013.1457	1	RRK072	0.08	9,813	13,001	75%	$ 2,681,000
E150.021672	Install Chemolite CHE TR03	2021.0094	1	CHE_TR1	0.15	35,066	47,806	73%	$ 5,986,000
E150.022038	Install Stockyards STY TR03	2021.0857	0	STY071	1000.00	12,795	9,720	132%	$ 6,314,000
E150.022705	Reinforce West Hastings WEH TR1	2021.0132	1	WEH_TR1	0.01	11,604	25,982	45%	$ 6,248,000
E150.022709	Install Williams Brothers TR4	2021.0127	1	WBP_TR3	0.03	11,616	29,400	40%	$ 5,715,000
E150.022735	Install Lone Oak LOK Feeder	2021.0108	1	LOK093	0.31	10,089	10,490	96%	$ 7,200,000
E150.022858	Install Inver Hills IVH TRs	2022.0812	1	RVA_TR1	1000.00	20,729	29,879	69%	$ 13,363,000
E150.023935	Install Feeder Tie RMT322-RMT311	2023.0791	1	RMT311	4.15	16,803	34,802	48%	$ 1,328,000
E150.023945	Reinforce Lone Oak LOK082 & LOK093	2022.0451	1	LOK062	0.51	13,249	12,553	106%	$ 1,160,000
E150.023946	Reinforce Lone Oak LOK062	2023.0162	0	LOK062	10.67	13,249	12,553	106%	$ 114,000
E150.023953	Reinforce Rogers Lake RLK073	2022.0453	1	RLK071	1.07	11,080	10,416	106%	$ 650,000
E150.023955	Reinforce Rogers Lake RLK071	2022.0309	0	RLK071	0.75	11,080	10,416	106%	$ 890,000
E150.023959	Reinforce Afton AFT321	2023.0958	1	AFT321	0.24	30,725	32,627	94%	$ 8,000,000
E150.023962	Reinforce Hastings HAS022	2022.0308	0	HAS022	1.66	11,000	10,310	107%	$ 400,000
E151.000726	Install Prior PRR TR2	2004.0884	1	PRR_TR1	0.08	17,860	30,611	58%	$ 7,360,000
E151.023981	Reinforce Merriam Park MPK063	2022.0304	0	MPK063	341.27	11,080	8,676	128%	$ 1,113,000
E151.023984	Reinforce Daytons Bluff DBL067	2023.0261	0	DBL067	0.13	10,095	11,062	91%	$ 1,200,000
E151.023986	Reinforce Merriam Park MPK061	2013.1541	0	MPK061	4.37	9,411	8,104	116%	$ 1,650,000
E151.023987	Reinforce Merriam Park MPK072 feeder	2023.0772	0	MPK072	0.31	6,779	8,328	81%	$ 1,625,000
E151.023988	Reinforce Merriam Park MPK081	2023.0774	0	MPK081	0.43	7,137	8,775	81%	$ 1,625,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2024 Forecasted Demand kVA	2024 Forecasted Capacity kVA	2024 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E151.023992	Reinforce Merriam Park MPK067	2023.0771	0	MPK067	1000.00	9,355	8,154	115%	$ 600,000
E151.023993	Reinforce Merriam Park MPK068	2023.0334	0	MPK068	11.65	10,249	9,744	105%	$ 600,000
E151.024008	Reinforce Merriam Park MPK087	2023.0336	0	MPK078	2.36	10,317	9,198	112%	$ 1,625,000
E151.024013	Reinforce Merriam Park MPK085	2023.0777	0	MPK085	1.56	8,572	9,943	86%	$ 876,000
E151.024018	Reinforce Upper Levee UPP081 feeder	2023.0466	0	UPP081	0.19	10,595	12,429	85%	$ 1,046,000
E151.024029	Reinforce Western WES061 and WES075	2005.0139	1	WES072	7.19	10,033	10,515	95%	$ 569,000
E151.024039	Reinforce WES065 and WES076	2023.1014	1	WES062	1.13	10,371	9,769	106%	$ 408,000
E151.024040	Reinfoce Western WES062 Feeder	2022.0306	0	WES062	4.37	10,371	9,769	106%	$ 193,000
E151.024041	Reinforce Western WES074 Feeder	2023.0488	0	WES074	3.50	10,085	9,322	108%	$ 354,000
E152.024015	Install Tracy Area Substation	2023.0999	0	TRA_TR1	1000.00	2,184	2,882	76%	$ 7,350,000
E154.010157	Install Albany ALB TR	2004.0942	1	ALB_TR2	11.76	12,076	11,588	104%	$ 6,800,000
E154.021667	Install Feeder Tie SDX312-FSL311	2020.0501	1	FSL311	1000.00	18,520	34,802	53%	$ 150,000
E154.022738	Install Dayton Area Sub	2022.0385	0	HSN312	1000.00	42,897	34,802	123%	$ 9,175,000
E154.022742	Reinforce Meire Grove TR1	2004.0086	0	MEI_TR1	1000.00	1,885	1,707	110%	$ 1,700,000
E154.022744	Install Glenwood GLD Feeder	2005.0076	1	GLD021	3.45	10,384	12,310	84%	$ 1,450,000
E154.022828	Install Blue Heron TR2	2004.0950	1	BLH_TR1	1000.00	11,299	9,561	118%	$ 6,100,000
E154.024024	Extend Avon Feeder AVN021	2004.0945	1	AVN_TR1	1.60	8,471	13,231	64%	$ 2,100,000
E154.024224	Purchase Hassan Area Land	2023.1135	0	HSN312	1000.00	42,897	34,802	123%	$ 900,000
E156.007927	Install Goose Lake GLK TR3	2005.0554	1	GLK_TR1	0.25	41,555	51,018	81%	$ 3,750,000
E156.011061	Install Wyoming WYO Feeder	2010.0166	1	WYO032	1.66	9,619	9,210	104%	$ 2,841,000
E156.011752	Install Lindstrom LIN Feeder	2008.0856	1	SCA021	1.41	11,184	9,322	120%	$ 862,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2011.0177	1	TLK_TR1	0.05	50,077	71,709	70%	$ 200,000
E156.011874	Install Birch Area Sub	2013.0062	1	LEX_TR3	1.42	57,668	71,709	80%	$ 9,300,000
E156.013545	Expand AHI substation	2011.0152	1	AHI_TR1	0.08	16,922	20,198	84%	$ 8,465,000
E156.015811	Reinforce Oakdale OAD073 & OAD075	2012.0572	1	TLK066	0.20	8,212	13,921	59%	$ 275,000

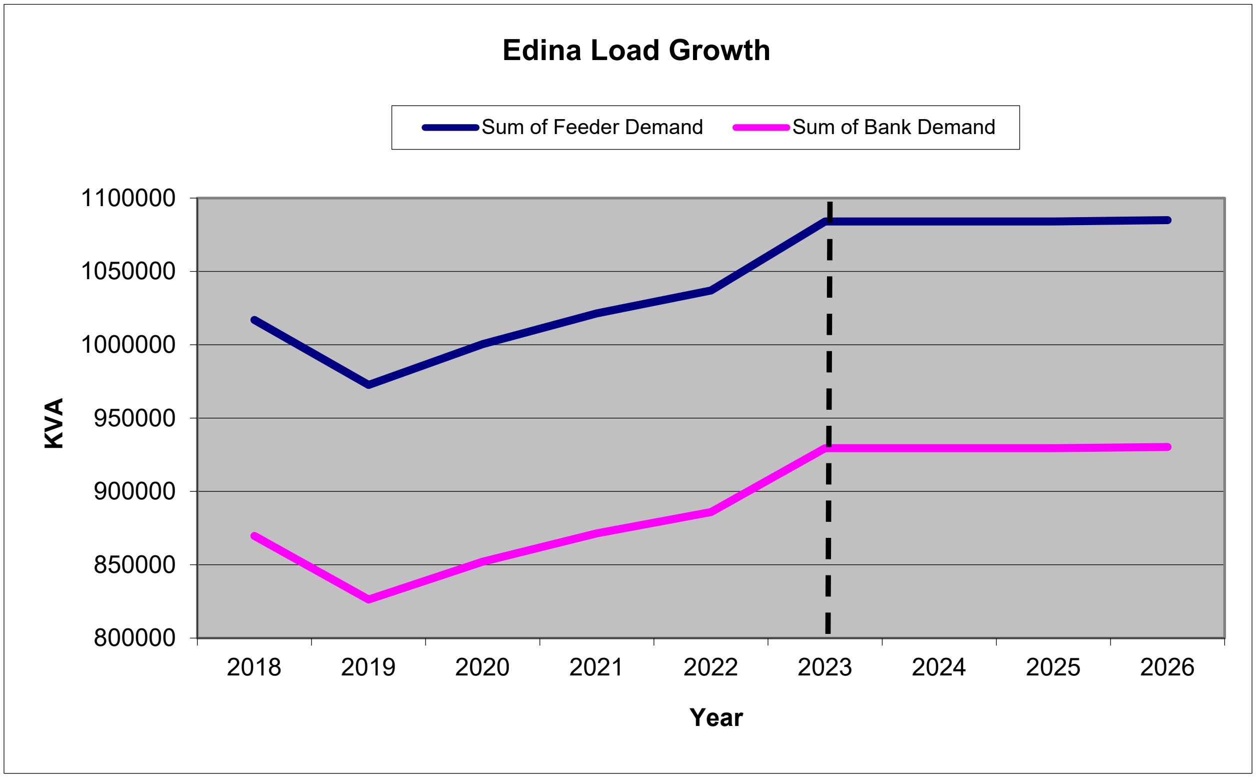
PROTECTED DATA SHADED

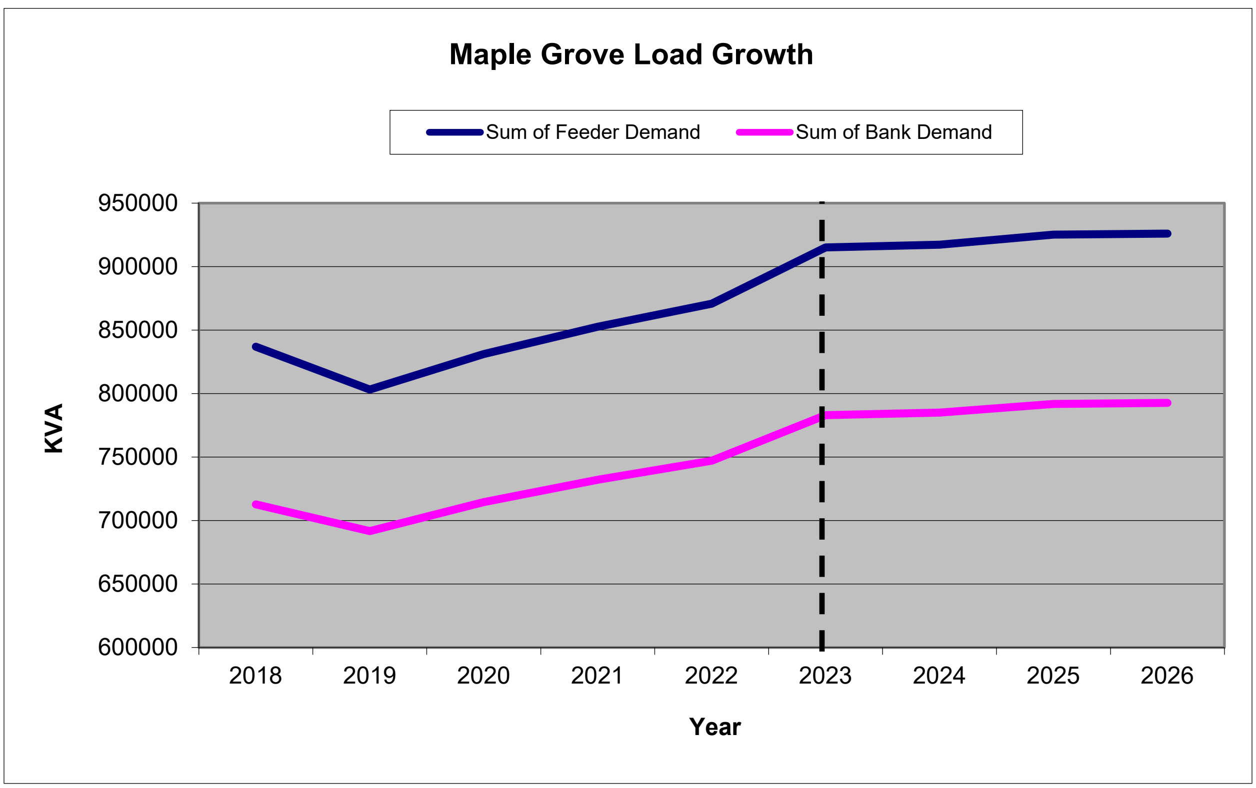
Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2024 Forecasted Demand kVA	2024 Forecasted Capacity kVA	2024 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2014.0459	1	RAM064	1.30	10,393	14,915	70%	$ 260,000

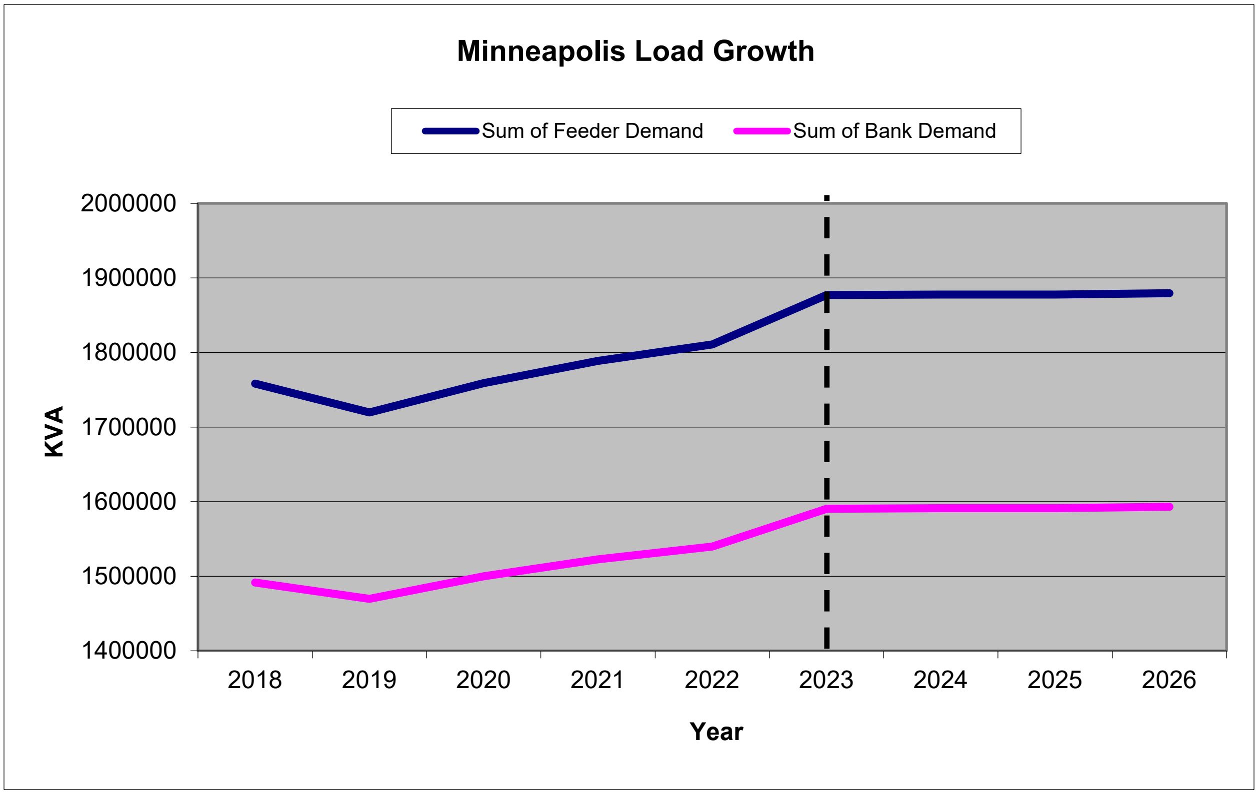
PROTECTED DATA ENDS]

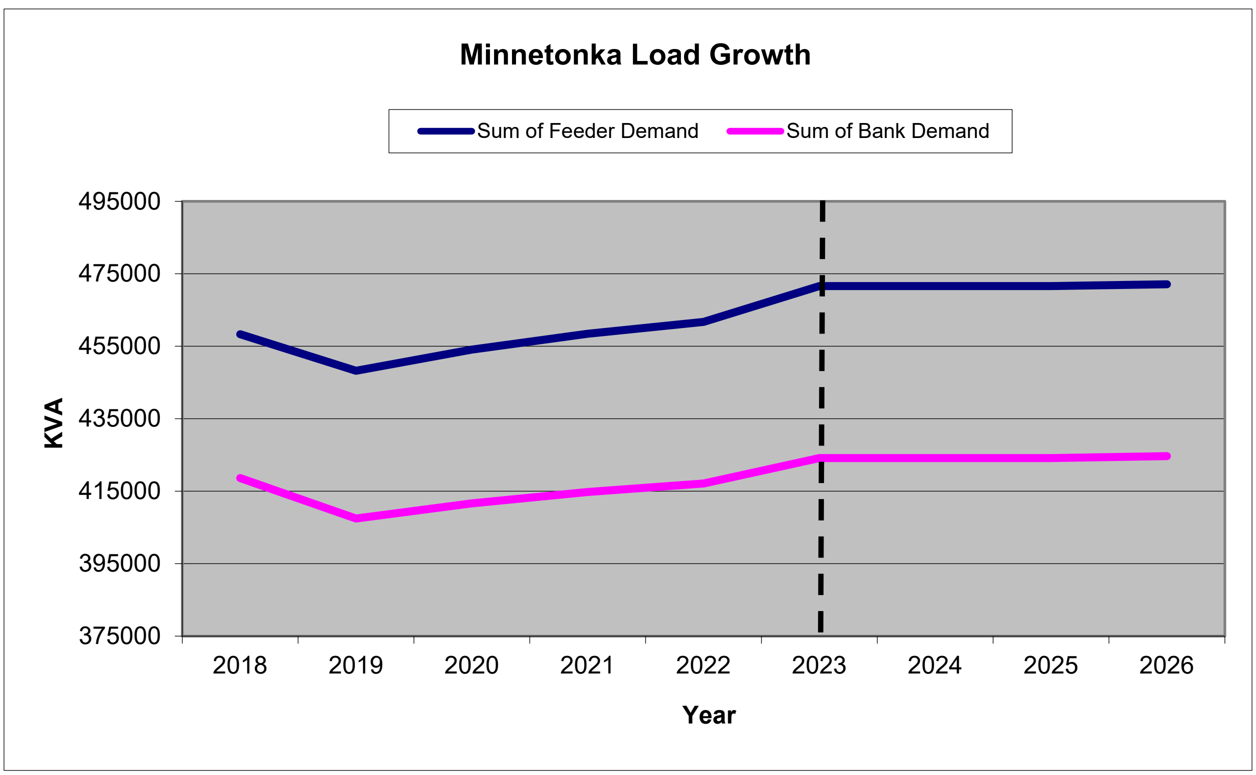
<u>Protected Data Justification</u>

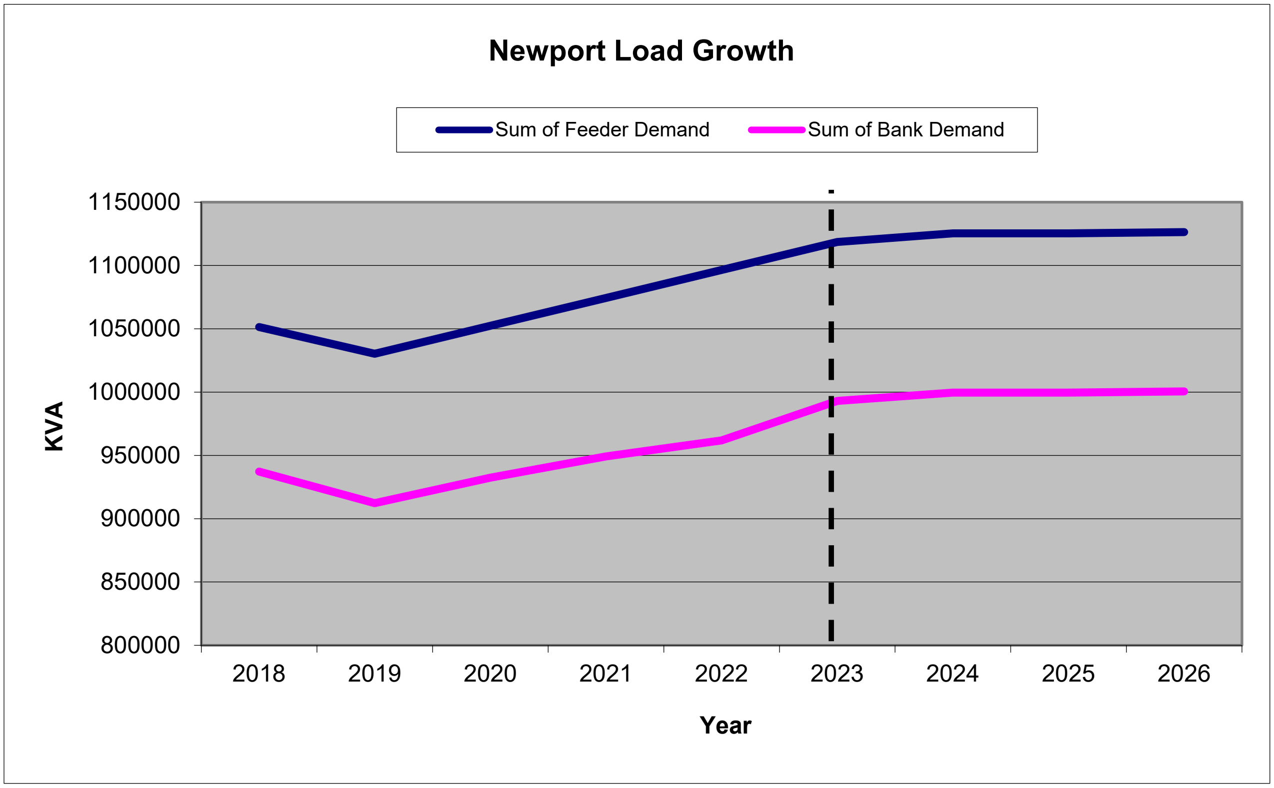
The shaded and marked columns in this spreadsheet contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

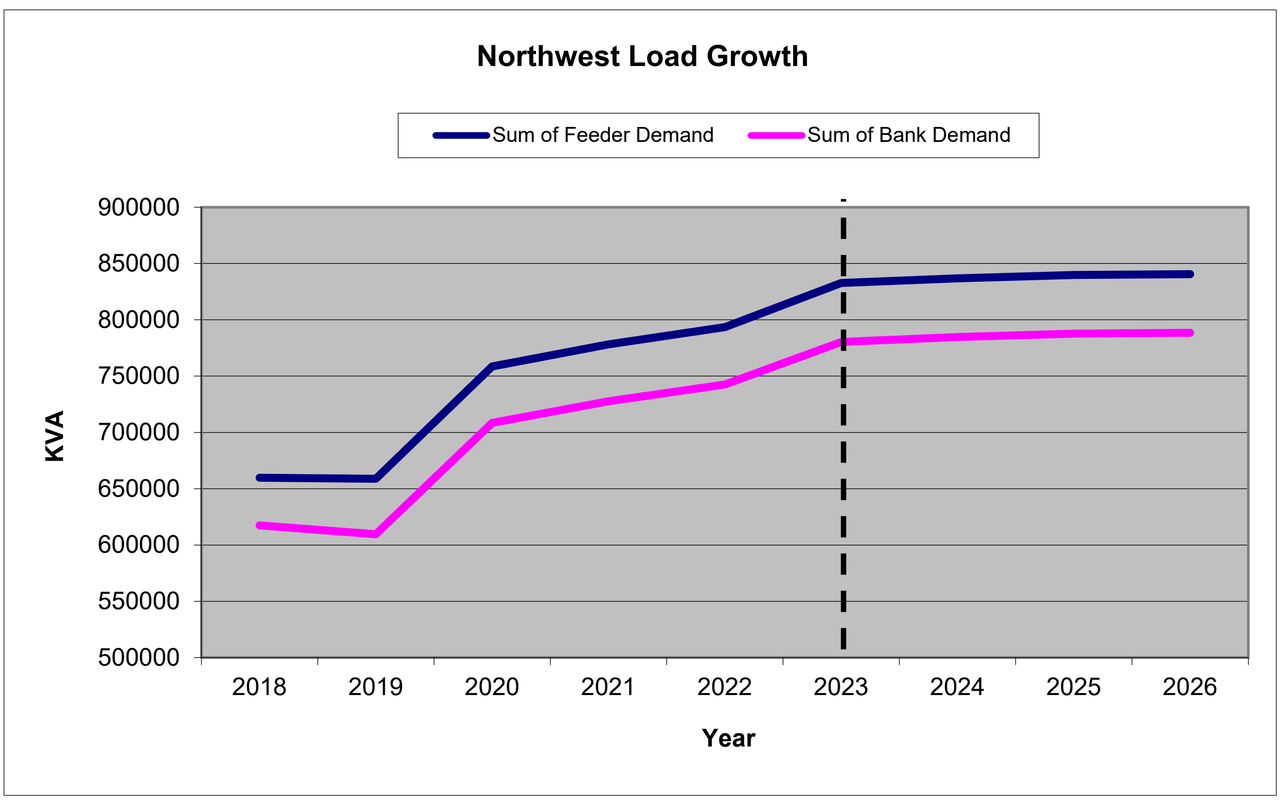

Edina Load Growth
Sum of Feeder Demand
Sum of Bank Demand
1100000
1050000
1000000
950000
900000
850000
800000
KVA
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year

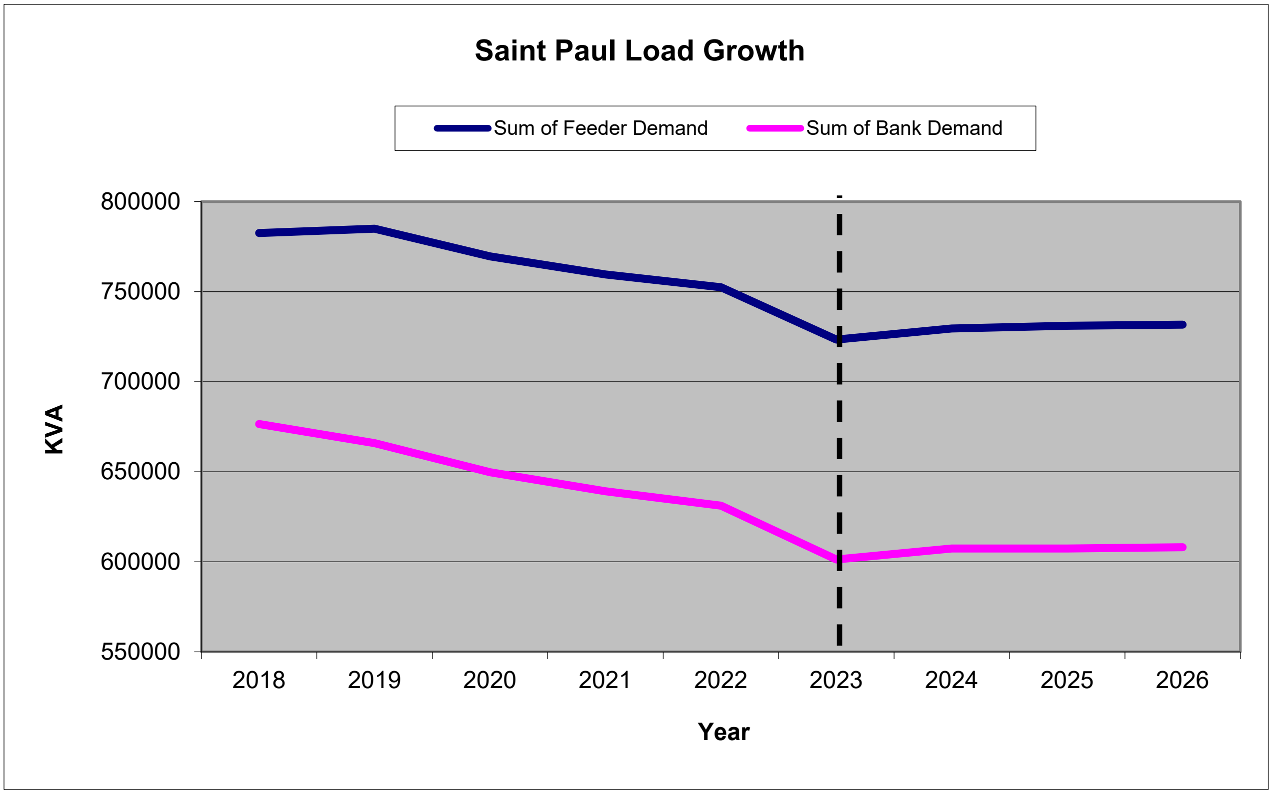

Maple Grove Load Growth
Sum of Feeder Demand
Sum of Bank Demand
950000
900000
850000
800000
750000
700000
650000
600000
KVA
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year

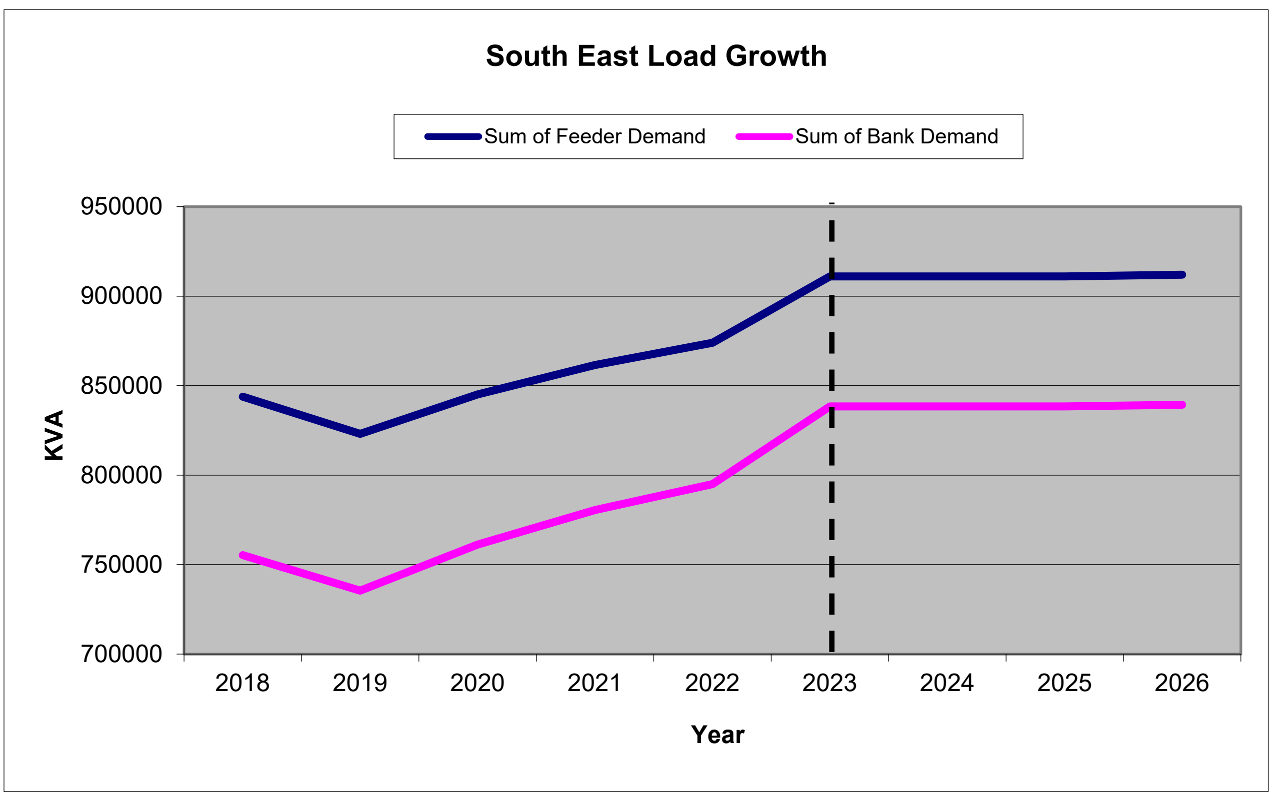

Minneapolis Load Growth
Sum of Feeder Demand
Sum of Bank Demand
2000000
1900000
1800000
1700000
1600000
1500000
1400000
KVA
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year

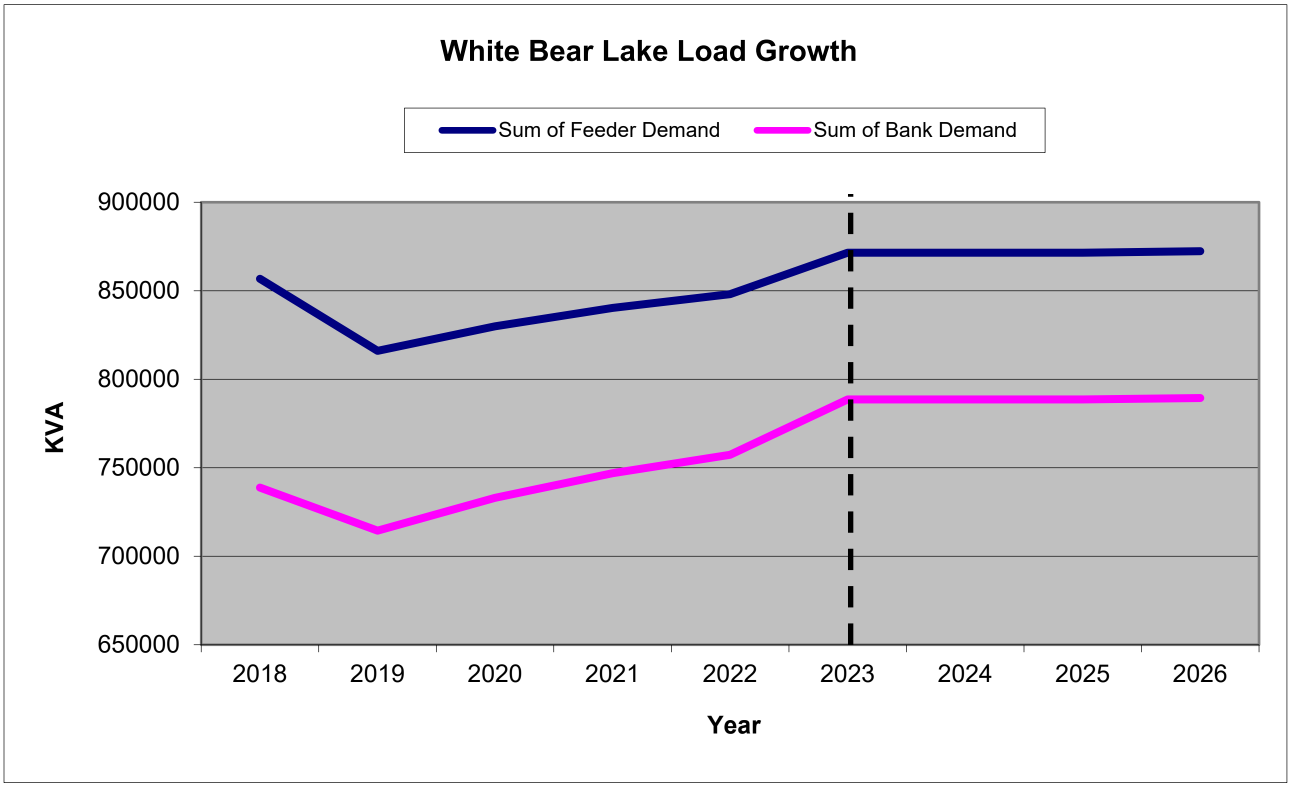

Minnetonka Load Growth
Sum of Feeder Demand
Sum of Bank Demand
495000
475000
455000
435000
415000
395000
375000
KVA
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year


Newport Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1150000
1100000
1050000
1000000
950000
900000
850000
800000
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year


Northwest Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
900000
850000
800000
750000
700000
650000
600000
550000
500000
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year


Saint Paul Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
800000
750000
700000
650000
600000
550000
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year


South East Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
950000
900000
850000
800000
750000
700000
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year


White Bear Lake Load Growth
Sum of Feeder Demand
Sum of Bank Demand
900000
850000
800000
750000
700000
650000
KVA
2018
2019
2020
2021
2022
2023
2024
2025
2026
Year

`

IDP Requirement 3.D.2.j requires that we provide:

Impacts to net present value of system costs (in NPV RR/MWh or MW)

As we have noted in our past IDPs, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. We continue to believe there are differing characteristics associated with the distribution system that make this complex to translate. That said, we have not been provided other directions, so we are providing a distribution-level calculation consistent with what we have provided in the past.

Our approach is similar to a jurisdictional cost of service – but for just the Distribution function of the Company. In general, a jurisdictional cost of service study includes the following financial data input sections: (1) capital structure; (2) cost of capital; (3) income tax rates; (4) rate base; (5) income statement; (6) income tax calculations; and (7) cash working capital computation.

We clarify that this "rate base" view of the Distribution function will not match the budget information we provide in this IDP, because the inputs to the NPV Revenue Requirements (RR) calculation are specific to just the distribution system located in Minnesota. As such, only costs that are direct-assigned to Distribution, and distribution assets located in the state of Minnesota are included. Common and general property in support of the Distribution function are not included in this view – but are represented in the distribution budget information provided elsewhere in this IDP. Similarly, other rate base is not included, and we are not including ratemaking treatments such as net operating losses.

Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital. It is generally comprised of the following major items:

- *Net Utility Plant.* Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.
- *Construction Work in Progress (CWIP).* In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.
- *Accumulated Deferred Income Taxes (ADIT).* Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation generally exceeds book

depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC)*. In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.
- *Other Rate Base*. Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

Rate base is generally calculated as outlined in Table 1 below.

Table 1: High Level Rate Base Calculation

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve
Less:	Average Accumulated Provision for Deferred Taxes
Plus:	Average Construction Work in Progress
Plus:	Average Working Capital
Equals:	Rate Base

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the 5-year budget period to derive an NPV of $290.9 million (in 2023 dollars).

Annual Revenue Requirement
Electric Distribution
2023-2028
Minnesota
(000's)

	Rate Analysis	2023	2024	2025	2026	2027	2028
1	Average Balances:						
2	Plant Investment	4,701,146	5,099,722	5,526,639	6,017,549	6,613,030	7,387,721
3	Depreciation Reserve	1,634,417	1,718,934	1,819,581	1,928,548	2,042,874	2,166,758
4	CWIP	55,744	72,976	103,596	133,276	210,795	302,239
5	Accumulated Deferred Taxes	579,288	580,002	583,036	590,145	603,772	624,361
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	2,543,185	2,873,764	3,227,617	3,632,132	4,177,179	4,898,841
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53						
10							
11	Expenses:						
12	Book Depreciation	139,800	153,267	166,941	180,855	199,634	224,033
13	Annual Deferred Tax	(137)	1,564	4,506	9,711	17,544	23,634
14	ITC Flow Thru	(264)	(256)	(242)	(222)	(193)	(162)
15	Property Taxes	51,288	56,945	61,086	68,166	75,236	82,862
16	subtotal expense = lines 12 thru 15	190,688	211,520	232,291	258,510	292,221	330,368
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	157,676	179,891	205,704	238,879	286,065	334,758
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	2,641	3,788	4,550	6,703	8,740	12,725
22							
23	AFUDC	3,848	5,617	6,801	9,877	13,292	19,576
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	52,135	60,062	67,457	75,912	87,303	102,386
27	Equity Return = line 6 x (line 46 + line 47)	123,599	139,665	156,862	176,522	203,011	238,084
28							
29	Tax Calculations:						
30	Equity Return = line 27	123,599	139,665	156,862	176,522	203,011	238,084
31	Taxable Expenses = lines 12 thru 14	139,400	154,576	171,205	190,344	216,985	247,505
32	plus Tax Additions = line 21	2,641	3,788	4,550	6,703	8,740	12,725
33	less Tax Deductions = (line 19 + line 23)	(161,525)	(185,508)	(212,505)	(248,756)	(299,356)	(354,333)
34	subtotal	104,115	112,520	120,112	124,813	129,379	143,980
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	41,995	45,385	48,447	50,344	52,185	58,075
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	41,995	45,385	48,447	50,344	52,185	58,075
39							
40	Total Capital Revenue Requirements	404,568	451,016	498,257	551,410	621,429	709,336
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	101,991	124,365	140,111	148,019	152,471	154,535
43	Total Revenue Requirements	506,560	575,381	638,367	699,429	773,900	863,871

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0100%**	**2.0700%**	**2.0700%**	**2.0700%**	**2.0700%**	**2.0700%**
45	**Short Term Debt**	**0.0400%**	**0.0200%**	**0.0200%**	**0.0200%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**4.8600%**	**4.8600%**	**4.8600%**	**4.8600%**	**4.8600%**	**4.8600%**
48	**Required Rate of Return**	**6.9100%**	**6.9500%**	**6.9500%**	**6.9500%**	**6.9500%**	**6.9500%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

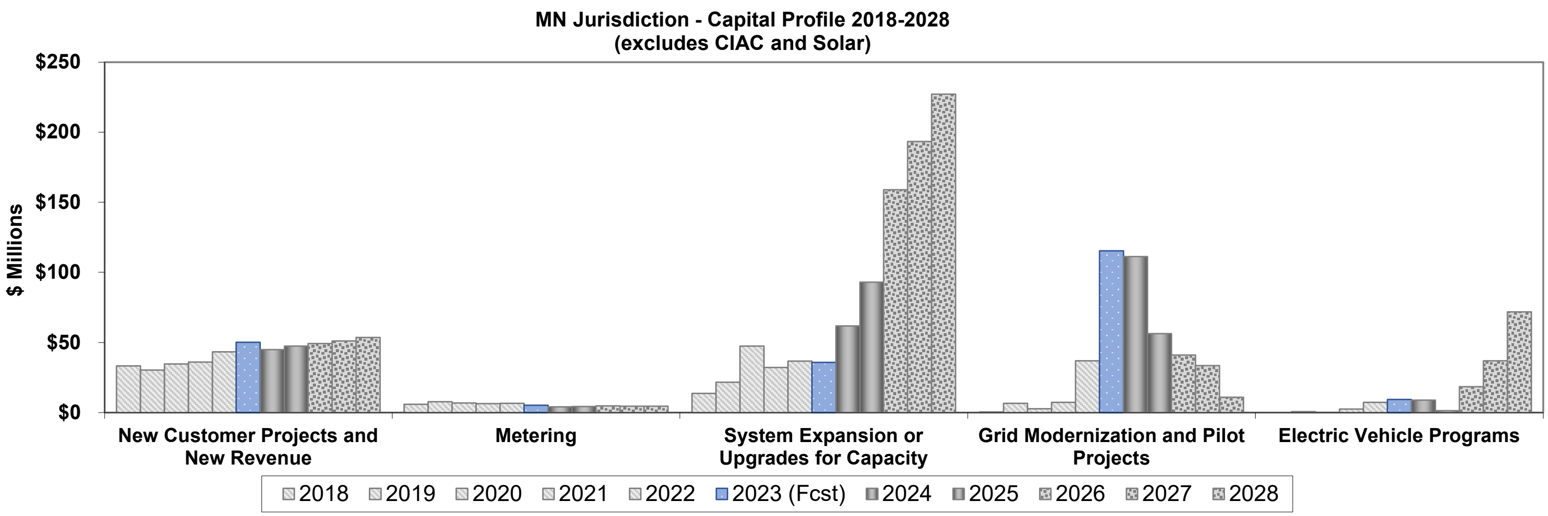
54	Growth in Total Revenue Requirements	-	68,821	62,986	61,062	74,471	89,971
55	Present Value of Growth in Total Revenue Requirements	290,874					

IDP Category full desc	General Category	Mitigation #	Mitigation Name	Risk Score	2024	2025	2026	2027	2028	Total
Age-Related Replacements and Asset Renewal	Blanket				36,411,001	37,503,006	38,626,995	39,784,995	41,776,004	194,102,001
	Program				100,418,524	137,068,657	170,695,673	196,251,526	199,777,552	804,211,933
	Project	E141.017673	Aldrich Mitigation	0.66	49,997		4,999,999	8,325,002	1,925,000	15,299,998
		E141.023581	Rebuild Garfield Ductline & Feeders	0.01	6,999,998	4,599,999	1,542,003			13,142,000
		E142.024278	C OH-UG BCR062 (Minnetonka)	NA	399,999					399,999
		E144.011660	ELR Install New Nerstrand Sub	0.34				200,000	3,449,996	3,649,996
		E144.013600	Convert Butterfield BTF 4kV	1.04	2,573,510					2,573,510
		E144.013622	Convert Lafayette LAF 4kV	0.27		100,001	1,949,998			2,049,999
		E144.021748	ELR Install Gaiter Lake Sub	13.17	4,473,509	300,000				4,773,509
		E144.024031	Convert Gaylord GAY 4kV	0.07		200,000	6,200,004			6,400,004
		E144.024050	Rebuild Waterville Feeder WAT081	0.01					5,600,002	5,600,002
		E144.024225	Essig Substation ELR	0.76	100,001	2,600,000				2,700,001
		E145.013623	Convert Larimore LAR 4kV	NA	173,507					173,507
		E146.022525	Rebuild Averill AVR Substation	0.76	5,810,938					5,810,938
		E151.020496	Rebuild Downtown St. Paul Manholes WEST	NA	450,003					450,003
		E151.020871	Relocate STP Tunnel Feeders	0.02	5,000,002	5,000,002	5,000,002	5,000,002	5,000,002	25,000,010
		E151.020897	Reinforce Daytons Bluff DBL Substation	1.06	11,700,004	10,400,000	2,199,999	2,499,997		26,800,000
		E152.024334	DER Rebuild Hadley HAD021	0.01	1,500,001					1,500,001
		E154.013603	Convert Bird Island BIS 4kV	1.27				100,001	2,150,000	2,250,001
		E154.013633	Convert Hector HEC 4kV	1.1				100,001	2,400,000	2,500,001
		E154.013634	Convert Montevideo MTV 4kV	2.83				100,001	2,499,999	2,600,000
		E154.019464	T Rebuild West St Cloud to Millwood	NA	249,998	749,998				999,996
		E154.021667	Install Feeder Tie SDX312-FSL311	56.7	149,996					149,996
		E154.022809	Rebuild Belgrade Substation	NA	1,336,753					1,336,753
		E154.023410	T Rebuild Glenwood GLD Feeder Exit	NA	449,999	250,000				699,999
		E154.023463	T Rebuild Cap Banks GLD Sub	NA	1,043,377	586,755				1,630,132
		E154.024021	Convert South Haven SOH 4kV	0.38				100,001	4,799,998	4,899,999
		E154.024027	Convert St Joseph STO 4kV	0.62				200,000	3,000,002	3,200,002
		NA	NA	NA	150,000	200,000				350,000
Age-Related Replacements and Asset Renewal Total					179,441,118	199,558,418	231,214,673	252,661,526	272,378,555	1,135,254,291
Electric Vehicle Programs	Program				8,943,600	1,372,300	18,361,600	36,873,000	71,843,800	137,394,300
Electric Vehicle Programs Total					8,943,600	1,372,300	18,361,600	36,873,000	71,843,800	137,394,300
Grid Modernization and Pilot Projects	Program					5,500,000	5,060,000	10,296,000	10,811,002	31,667,002
	Project	NA	NA	NA	111,288,920	50,825,514	35,888,234	23,246,250		221,248,918
Grid Modernization and Pilot Projects Total					111,288,920	56,325,514	40,948,234	33,542,250	10,811,002	252,915,920
Metering	Blanket				4,136,000	4,418,000	4,700,000	4,606,000	4,512,000	22,372,000
Metering Total					4,136,000	4,418,000	4,700,000	4,606,000	4,512,000	22,372,000
New Customer Projects and New Revenue	Blanket				44,927,998	47,581,999	49,169,000	51,091,999	53,492,000	246,262,996
New Customer Projects and New Revenue Total					44,927,998	47,581,999	49,169,000	51,091,999	53,492,000	246,262,996
Non-Investment	Blanket				(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(20,000,000)
Non-Investment Total					(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(20,000,000)
Other	Program				73,820,182	54,998,245	54,758,774	56,180,196	63,359,414	303,116,810
	Project	E150.022735	Install Lone Oak LOK Feeder	0.31				173,507		173,507
		E151.020897	Reinforce Daytons Bluff DBL Substation	1.06	86,755	86,755	86,755			260,265
		E153.021678	Install South Renner SRN TR02	1000	173,507					173,507
Other Total					74,080,444	55,084,999	54,845,529	56,353,703	63,359,414	303,724,089
Projects related to Local (or other) Government-Requirements	Blanket				36,025,006	39,574,010	40,551,004	41,558,003	43,285,001	200,993,024
	Project	E142.024163	Relocate WWK321 (Hwy 212)	NA	1,159,999					1,159,999
Projects related to Local (or other) Government-Requirements Total					37,185,005	39,574,010	40,551,004	41,558,003	43,285,001	202,153,023
System Expansion or Upgrades for Capacity	Blanket				10,185,003	10,310,000	12,439,999	14,574,001	17,003,004	64,512,007
	Program				5,299,999	31,300,000	85,299,998	108,360,000	109,794,999	340,054,996
	Project	E141.019925	SUBS Reinforce Gopher TR1	0.02					300,003	300,003
		E141.019928	Extend Saint Louis Park SLP092	3.47	900,000					900,000
		E141.019956	Reinforce Terminal TER073	0.72		1,100,001				1,100,001
		E141.019958	Reinforce Moore Lake MOL071	0.3				550,001		550,001
		E141.020729	Reinforce Saint Louis Park SLP092	0.33				4,050,000		4,050,000

IDP Category full desc	General Category	Mitigation #	Mitigation Name	Risk Score	2024	2025	2026	2027	2028	Total
		E141.021648	Reinforce Elliot Park ELP081	0.8		400,003				400,003
		E141.021663	Extend Southtown Feeder SOU069	1.12		350,000				350,000
		E141.022787	Reinforce SLP85 Feeder	0.24				2,710,001		2,710,001
		E141.024063	Install Midtown MDT064	0.97	3,469,996					3,469,996
		E141.024064	Extend Elliot Park Feeder ELP082	0.65			309,999			309,999
		E141.024065	Reinforce Medicine Lake MEL073	1.2		1,000,000				1,000,000
		E141.024066	Reinforce Medicine Lake MEL089	0.38				2,160,001		2,160,001
		E141.024067	Install Midtown MDT072 Feeder	0.01					5,319,999	5,319,999
		E141.024119	Reinforce Elliot Park ELP071 Feeder	0.01					530,002	530,002
		E142.011721	Install Orono ORO TR2 & Feeder	0.22			199,999	3,900,004		4,100,003
		E142.013437	Install Excelsior EXC TR2	0.01					3,900,000	3,900,000
		E142.024044	Install Gleason Lake GSL343	0.14				1,685,000		1,685,000
		E142.024045	Install Dahlgren DHL062	1.35		1,410,000				1,410,000
		E143.017702	Install Viking VKG Feeder	0.52		4,195,000				4,195,000
		E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	0.02				199,999	5,546,999	5,746,998
		E143.019054	Reinforce Edina EDA062	0.7		500,000				500,000
		E143.020385	C Install East Bloomington EBL Fdr S	NA		2,000,001	2,000,001			4,000,002
		E143.022265	Install Hyland Lake HYL TR01	0.16	4,125,001					4,125,001
		E143.022794	Install Wilson Feeder WIL064	28.61		1,590,004				1,590,004
		E143.022795	Extend Hyland Lake HYL074	4.23	925,003					925,003
		E143.024049	Extend East Bloomington EBL066	0.32				550,001		550,001
		E143.024051	Reinforce East Bloomington EBL062	13.5	950,001					950,001
		E143.024059	Load Transfer WIL089 to WIL092	47.57	19,999					19,999
		E144.000791	Install La Crescent Area Sub	2.71	2,825,004	3,825,000				6,650,004
		E144.000793	Install Zumbrota ZUM TR	0.43			199,999	2,849,998		3,049,997
		E144.002712	Install Goodview GVW Feeder	22.3				1,800,001		1,800,001
		E144.008708	Install Cannon Falls CAF TR2	0.88		199,999	2,250,000			2,449,999
		E144.010884	Install Belle Plaine Area Sub	0.1				400,001	6,000,001	6,400,002
		E144.010889	Reinforce Pine Island TR1	0.65		199,999	2,300,001			2,500,000
		E144.010920	Reinforce Burnside BUR TR2	0.59			199,999	1,500,002	3,200,000	4,900,001
		E144.015692	Install Summit Ave SMT TR3	3.44	199,999	1,500,002	2,400,001			4,100,002
		E144.018971	Reinforce Veseli VES TR1	2.76	2,199,999					2,199,999
		E144.020614	Reinforce Faribault FAB TR2	3.14	199,999	1,200,000	2,500,000			3,899,999
		E144.023176	Install Sibley Park SIP TR03	0.02				199,999	3,350,003	3,550,002
		E144.024034	Reinforce Waterville TR3	0.36			199,999	3,199,999		3,399,998
		E144.024037	Install West Byron WEB TR2	1.93		199,999	5,100,002			5,300,001
		E144.024038	Reinf West Faribault WEF TR7	1.17		199,999	1,600,001			1,800,000
		E144.024046	Reinforce Wabasha WAB021	4.14	199,999					199,999
		E144.024052	C Reinforce Fair Park FAP062 Feeder	NA	2,200,001					2,200,001
		E146.024017	Install Averill AVR TR02	0.02				100,001	2,300,000	2,400,001
		E147.013373	Reinforce Basset Creek BCR TR1	0.04				199,999	2,199,999	2,399,998
		E147.013374	Reinforce Elm Creek TR1 to 50 MVA	0.04				100,001	2,300,000	2,400,001
		E147.013379	Install West Coon Rapids WCR TR	0.02				199,999	3,400,000	3,599,999
		E147.014487	Reinforce Twin Lakes TWL061	1.34	1,815,002					1,815,002
		E147.015683	Install Osseo OSS TR3	0.01				199,999	4,400,001	4,600,000
		E147.016682	Reinforce TWL079 and TWL081	3.12	5,500,000					5,500,000
		E147.022783	Reinforce All Osseo OSS Feeders	2.24	4,049,995	4,249,997				8,299,992
		E147.024025	Reinforce Twin Lakes TWL065	0.01					2,500,000	2,500,000
		E147.024026	Reinforce Twin Lakes TWL068	0.01					750,001	750,001
		E147.024028	Reinforce Parkers Lake PKL085	5.12	149,998					149,998
		E147.024033	Reinforce Parkers Lake PKL065	0.01					3,700,001	3,700,001
		E147.024193	Reinforce Twin Lakes TWL078	0.01					3,499,998	3,499,998
		E147.024221	Reinforce Brooklyn Park BRP072	0.01					500,000	500,000
		E147.024227	Load Trnsfr CRL033 CRL027 CRL031	0.01					300,000	300,000
		E150.013326	Install West Hastings WEH TR2	0.01				199,999	5,848,000	6,047,999
		E150.020608	Install Red Rock RRK073	0.08					2,681,002	2,681,002
		E150.021672	Install Chemolite CHE TR03	0.15			199,999	5,785,999		5,985,998
		E150.022038	Install Stockyards STY TR03	10.39	2,543,376	3,737,508				6,280,884
		E150.022705	Reinforce West Hastings WEH TR1	0.01				199,999	6,021,510	6,221,509

IDP Category full desc	General Category	Mitigation #	Mitigation Name	Risk Score	2024	2025	2026	2027	2028	Total
		E150.022709	Install Williams Brothers TR4	0.03				199,999	5,315,001	5,515,000
		E150.022735	Install Lone Oak LOK Feeder	0.31			199,999	6,799,999		6,999,998
		E150.022858	Install Inver Hills IVH TRs	0.05	199,999	1,500,002	11,662,997			13,362,998
		E150.023935	Install Feeder Tie RMT322-RMT311	4.15	1,327,998					1,327,998
		E150.023945	Reinforce Lone Oak LOK082 & LOK093	0.51				1,160,000		1,160,000
		E150.023946	Reinforce Lone Oak LOK062	10.67	114,000					114,000
		E150.023953	Reinforce Rogers Lake RLK073	1.07		650,004				650,004
		E150.023955	Reinforce Rogers Lake RLK071	0.75		890,001				890,001
		E150.023959	Reinforce Afton AFT321	0.24			199,999	7,800,002		8,000,001
		E150.023962	Reinforce Hastings HAS022	1.66		400,003				400,003
		E150.024167	Install Lone Oak LOK TR3	0.01				199,999	3,680,003	3,880,002
		E151.000726	Install Prior PRR TR2	0.08				199,999	7,160,002	7,360,001
		E151.012409	Install Western WES TR3 & Feeders	0.01					5,300,001	5,300,001
		E151.023981	Reinforce Merriam Park MPK063	341.27	1,113,001					1,113,001
		E151.023984	Reinforce Daytons Bluff DBL067	0.13					1,199,999	1,199,999
		E151.023986	Reinforce Merriam Park MPK061	4.37	1,650,000					1,650,000
		E151.023987	Reinforce Merriam Park MPK072 feeder	0.31				1,625,002		1,625,002
		E151.023988	Reinforce Merriam Park MPK081	0.43				1,625,002		1,625,002
		E151.023992	Reinforce Merriam Park MPK067	10.36	600,001					600,001
		E151.023993	Reinforce Merriam Park MPK068	11.65	600,001					600,001
		E151.024003	C Reinforce Western WES072 Feeder	NA	10,000					10,000
		E151.024004	C Reinforce Western WES064 feeder	NA	10,000					10,000
		E151.024008	Reinforce Merriam Park MPK087	2.36	1,625,002					1,625,002
		E151.024013	Reinforce Merriam Park MPK085	1.56		876,000				876,000
		E151.024018	Reinforce Upper Levee UPP081 feeder	0.19				1,046,003		1,046,003
		E151.024029	Reinforce Western WES061 and WES075	7.19	568,999					568,999
		E151.024039	Reinforce WES065 and WES076	1.13		407,998				407,998
		E151.024040	Reinfoce Western WES062 Feeder	4.37	193,000					193,000
		E151.024041	Reinforce Western WES074 Feeder	3.5	354,001					354,001
		E152.024015	Install Tracy Area Substation	0.74	699,999	1,500,002	4,916,885	200,000		7,316,886
		E153.024023	Install Dell Rapids Area Substation	0.14			500,000	12,566,885		13,066,885
		E154.010157	Install Albany ALB TR	11.76	199,999	2,499,999	4,099,999			6,799,997
		E154.018960	Reinforce Glenwood GLD Sub Equip	0.05				100,001	600,000	700,001
		E154.022738	Install Dayton Area Sub	21.05	199,999	7,365,066	1,599,999			9,165,064
		E154.022742	Reinforce Meire Grove TR1	0.02		100,001	1,599,999			1,700,000
		E154.022744	Install Glenwood GLD Feeder	3.45	1,450,000					1,450,000
		E154.022828	Install Blue Heron TR2	1.2	199,999	1,500,002	4,400,001			6,100,002
		E154.024024	Extend Avon Feeder AVN021	1.6		2,099,999				2,099,999
		E154.024224	Purchase Hassan Area Land	0.01	600,000	300,003				900,003
		E156.007927	Install Goose Lake GLK TR3	0.25			100,001	3,650,000		3,750,001
		E156.010177	Install Kohlman Lake KOL Feeder	0.01			4,520,000			4,520,000
		E156.011061	Install Wyoming WYO Feeder	1.66	697,248	1,052,999	1,052,999			2,803,246
		E156.011752	Install Lindstrom LIN Feeder	1.41		862,000				862,000
		E156.011764	Reinforce Tanners Lake TLK Sub Equip	0.05					199,999	199,999
		E156.011874	Install Birch Area Sub	1.42	807,277	1,500,002	6,900,002			9,207,281
		E156.013545	Expand AHI substation	0.08				199,999	8,264,999	8,464,998
		E156.015811	Reinforce Oakdale OAD073 & OAD075	0.2				275,000		275,000
		E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	1.3	49,996	209,999				259,995
		NA	NA	NA	800,000					800,000
System Expansion or Upgrades for Capacity Total					61,828,893	93,181,592	158,952,877	193,322,894	227,065,526	734,351,783
System Expansion or Upgrades for Reliability and Power Quality	Program				38,656,003	55,401,005	76,426,003	201,154,995	327,955,001	699,593,007
System Expansion or Upgrades for Reliability and Power Quality Total					38,656,003	55,401,005	76,426,003	201,154,995	327,955,001	699,593,007
Grand Total					**556,487,981**	**548,497,838**	**671,168,920**	**867,164,370**	**1,070,702,299**	**3,714,021,410**

	2018	2019	2020	2021	2022	2023 (Fcst)	2024	2025	2026	2027	2028
New Customer Projects and New Revenue	$33.3	$30.4	$34.5	$36.1	$43.3	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5
Metering	$5.9	$7.6	$6.9	$6.3	$6.7	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5
System Expansion or Upgrades for Capacity	$13.6	$21.6	$47.4	$32.1	$36.7	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1
Grid Modernization and Pilot Projects	$0.4	$6.6	$2.7	$7.4	$36.9	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8
Electric Vehicle Programs	$0.0	$0.6	$0.1	$2.5	$7.2	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8



New Customer Projects and New Revenue (Extensions, Services, Streetlights)

- Based on estimated cost per meter and growth assumptions.
- Growth assumptions based on historical results, internal growth projections and known trends in service territories. Assumes current trends continue and minimal YOY growth.

Metering (Meter Purchases, does not include AMI)

- Includes 'business-as-usual' meter costs, not metering expenditures associated with our AMI plans.
- Decreasing trends driven by AMI rollout.

System Expansion or Upgrades for Capacity (Reinforcements)

- Continued focus on risk minimization including contingency and overload risks. Annual amounts will fluctuate based on needs in North and South Dakota, as well as timing of large projects.
- Includes the Grid Reinforcement and Hosting Capacity programs which is driving the uptick in years 3-5.

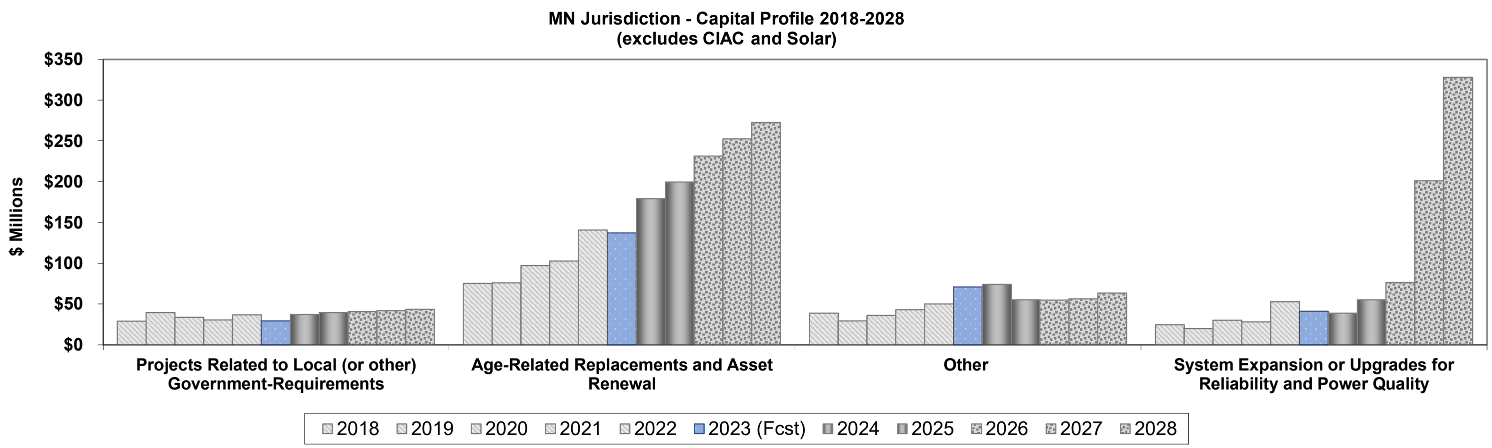
Grid Modernization and Pilot Projects

- Includes major grid modernization projects including AMI, FAN, ADMS, and FLISR.

Electric Vehicles Programs

- Includes Electric Vehicle Programs.

	2018	2019	2020	2021	2022	2023 (Fcst)	2024	2025	2026	2027	2028
Projects Related to Local (or other) Government-Requirements	$28.9	$39.3	$33.6	$30.4	$36.6	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3
Age-Related Replacements and Asset Renewal	$75.2	$75.7	$96.9	$102.4	$140.8	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4
Other	$38.5	$29.0	$35.9	$43.0	$49.8	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4
System Expansion or Upgrades for Reliability and Power Quality	$24.5	$19.6	$29.8	$27.9	$52.6	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0



Projects Related to Local (or other) Government-Requirements (Mandates)

- Outyear budgets assume strong trends continue with large projects scheduled through 2028. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.

Age-Related Replacements and Asset Renewal (Rebuilds, Conversions)

- Comprehensive suite of programs and projects aimed at replacing aging infrastructure. Includes funds for failure restoration.
- Increasing aging infrastructure population driving increased budgets including pole replacements, substation equipment, network equipment and various discrete projects to address aging infrastructure or reliability (substation rebuilds, 4kV conversions, etc.).

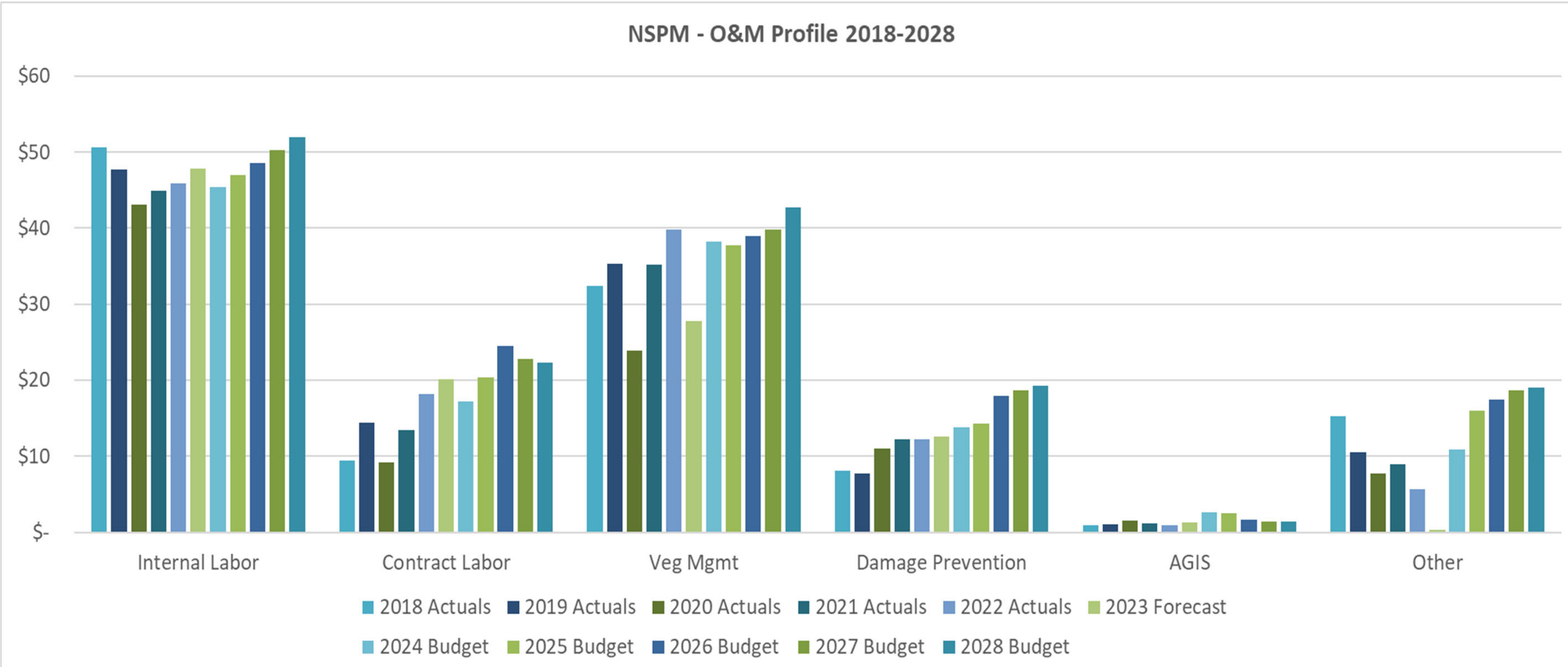
Other (Fleet, Tools, Communication Equipment, Transformer Purchases)

- Includes continuing programs for installing communication in our downtown networks (Network Monitoring), privatizing our substation communication network (Fiber Buildout) and increasing cyber security (Cyber Security).

System Expansion or Upgrades for Reliability and Power Quality (Cable Replacement and Reliability Programs)

- Includes continuing reliability programs focused on replacing infrastructure that is experiencing high failure rates, increase in outer years driven by potential resilience investments

Figure 1: Distribution O&M Profile Trend (2018 to 2028)
NSPM – Total Company Electric



Other: Includes materials, employee expenses, transportation costs, first set credits, bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Community	Carbon/GHG Reduction Goal	Renewable Energy Goal	Efficiency or Electrification Goal	Other
Bloomington*◈	75% for city-wide energy related, 95% for electricity related GHG emissions by 2035		Yes	Strategies for renewables, electrification
Burnsville*◈	40% by 2030, 80% by 2050 for community-wide GHG emissions	7.5% on-site solar (or REC purchase) for residential and commercial by 2030, 100% for all city owned facilities by 2030	10% decrease in residential and commercial electric use from 2016 numbers by 2030	Creating Energy Action Plan
Coon Rapids◈	35% by 2030 for GHG emissions			Strategies for renewables
Cottage Grove	Yes	Yes		
Eden Prairie*◈	30% by 2025, 80% by 2050 for GHG emissions	5% in-boundary by 2025, 10% by 2030		Climate Action Plan, Strategies for renewables, electrification
Edina*◈	30% by 2025, 80% by 2050 for GHG emissions	100% by 2030 for municipal, 100% by 2050 for community-wide, 10% in-boundary by 2030	10% gas to electric by 2030, full electrification by 2050	Climate Action Plan
Falcon Heights◈	80% by 2030	50% by 2030	100% of municipal buildings by 2030	Creating Energy Action Plan
Faribault*◈	Yes		1% annual reduction in energy spending from 2015	Creating Energy Action Plan, Strategies for renewables
Fridley*◈	5% by 2025, 25% by 2030	Yes	Reduce community energy use by 30% by 2030	
Golden Valley*◈	30% by 2030	Yes		Strategies for renewables, electrification
Hastings*◈				Energy Action Plan
Hennepin County*	45% by 2030, net zero by 2050	Carbon-free electricity for county by 2035, 10% on-site solar by 2030	3%/year reduce operational energy through 2030	Strategies for electrification
Hopkins◈				Creating Energy Action Plan
Inver Grove Heights*◈	Avoid 16,000 MTCO2e by 2025 and 28,000 by 2030	Increase on-site solar and renewables	Save 20 GWH of electricity by 2025, 39 GWH by 2030	Energy Action Plan
La Crescent*◈	Avoid 455 MTCO2e by 2030	Increase on-site solar and renewables	Promote DSM, Save 1.7 GWH by 2030	Energy Action Plan, Strategies for renewables, electrification
Mahtomedi*◈	30% by 2030, 100% by 2050	Double number of renewable energy subscribers in a year	1.4% annual energy savings, 19% by 2030	
Mankato		Yes		
Maplewood*◈	20% by 2025, 80% by 2050	50% by 2040, 15% on-site solar by 2030, 100% municipal renewables by 2040		Climate Action Plan/Sustainability Plan, Strategies for renewables, electrification
Minneapolis*	65% by 2030, 90% by 2040, net zero by 2050	100% by 2023 for municipal, 10% in-boundary by 2025, 100% by 2030 community-wide	Reduce energy use 17% by 2025	
Minnetonka*◈	Reduction of 160,000 MTCO2e energy related GHG emissions by 2031 or 41% by 2030	100% solar for city operations by 2020		Developing Climate Action Plan, Strategies for electrification
New Brighton◈				Developing Energy and Climate Action Plan
Northfield*◈	100% carbon neutral by 2040	10% in-boundary renewable electricity by 2030		Climate Action Plan, Strategies for renewables, electrification
Ramsey County*	30% by 2025, 80% by 2050	Promote on-site solar and renewables	Energy use reduction: 30% by 2025, 80% by 2050	
Red Wing*◈	80% by 2040 for GHG emissions	100% by 2040 community-wide	Reduce energy consumption 30% by 2030, 50% local vehicle use with electric or non/low-carbon fuels by 2030	Climate Action Plan/Sustainability Plan
Richfield*◈	15% by 2032 for GHG emissions	On-site solar and renewables		Energy Action Plan
Robbinsdale◈				Energy Action Plan, Strategies for renewables
Rosemount*◈	15% by 2030, 50% by 2050	75% municipal renewables	Reduce energy use 5% by 2020, 15% by 2030	
Roseville*◈	80% by 2050	100% renewable for city operations by 2040 with 25% on-site generation		Strategies for electrification
Saint Paul*◈	50% by 2030, 100% by 2050	10% in-boundary, 200 MW by 2030		Climate Action and Resilience Plan, Strategies for renewables, electrification
Scandia	Yes	Yes		
Shoreview◈				Developing Energy Action Plan
Shorewood◈				Energy Action Plan
St. Cloud*◈	100% by 2040	Replace 21.8 GWh for institutions and businesses with renewables by 2026, 100% by 2030	Decarbonization of building energy use, carbon neutral for building energy and transportation by 2038, Save $9.2M in energy costs	
St. Louis Park*◈	55% by 2030, 100% carbon neutral by 2040	100% by 2030	30% energy savings by 2030	Climate Action Plan, Strategies for renewables, electrification
Stillwater◈				Developing Energy Action Plan
Vadnais Heights				GreenStep Cities Pilot Program
Washington County*	30% by 2025, 80% by 2050		15% reduction in building energy by 2025	
Wayzata*◈			Reduce energy use 30% by 2025	Energy Action Plan, Strategies for renewables
Winona*◈	Carbon neutral by 2050		Reduce energy use 10% by 2025	Sustainability Plan, Strategies for renewables

* Community listed in the April 11, 2022 Letter from the Cities of Edina, Richfield, Saint Paul, and St. Louis Park (Docket No. E002/M-21-694).
◈Partners in Energy - Minnesota Community Participation

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL TO AMEND THE CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ITS ADVANCED GRID INTELLIGENCE AND SECURITY (AGIS) INITIATIVE	)))))))	**PROCEEDING NO. 21A-0279E**

UNANIMOUS COMPREHENSIVE SETTLEMENT AGREEMENT

Table of Contents

INTRODUCTION AND IDENTIFICATION OF PARTIES

This Unanimous Comprehensive Settlement Agreement ("Settlement Agreement" or "Agreement") is entered into by Public Service Company of Colorado ("Public Service" or the "Company"), Trial Staff ("Staff") of the Colorado Public Utilities Commission ("Commission"), the Office of the Utility Consumer Advocate ("UCA"), Mission:Data Coalition, Inc. ("Mission:Data"), Western Resource Advocates ("WRA"), Utilidata, Inc. ("Utilidata"), Itron, Inc. ("Itron"), the Colorado Solar and Storage Association ("COSSA"), and the Solar Energy Industries Association ("SEIA") (collectively the "Settling Parties") pursuant to Rule 1408 of the Commission's Rules of Practice and Procedure, 4 CCR 723-1. This Settlement Agreement is intended to resolve all issues that were raised in this proceeding with respect to the Company's Verified Application ("Application") to amend the Certificate of Public Convenience and Necessity ("CPCN") granted in Proceeding No. 16A-0588E for its Advanced Grid Intelligence and Security ("AGIS") Initiative (the "AGIS CPCN") relating to the deployment of Distributed Intelligence ("DI") capabilities of the Itron advanced meter selected by the Company (i.e., currently, Itron's Riva 4.2 family of meters).

BACKGROUND

On June 15, 2021, the Company filed its Application in this proceeding requesting that the Commission amend the AGIS CPCN, along with the supporting Direct Testimony and Attachments of five witnesses: Ms. Brooke A. Trammell; Mr. Emmett R. Romine; Mr. Victor R. Huston; Mr. Briston D. Jones; and, Mr. Mark Raak. The Commission noticed the Company's Application on June 16, 2021. Parties subsequently filed pleadings either exercising rights of intervention (Staff and the UCA) or seeking leave to intervene (the other intervening Parties). On July 28, 2021, the Commission deemed the Application complete and referred this proceeding to the Administrative Law Judge ("ALJ") by minute entry.

Answer Testimony from witnesses testifying on behalf of Staff, WRA, Itron, Mission:data, and Utilidata was filed on December 3, 2021. The Company filed Rebuttal Testimony on January 25, 2021, and WRA, Mission:data, Itron, and COSSA/SEIA filed Cross-Answer Testimony that same day.

Following the filing of Rebuttal Testimony, the Settling Parties commenced settlement negotiations and, on February 14, 2022, requested the ALJ vacate the scheduled first day of the hearing and commence the hearing on February 16, 2022. The Settling Parties then filed a Notice of Unanimous and Comprehensive Settlement in Principle on February 15, 2022.

This Settlement Agreement represents the comprehensive agreement of the Settling Parties to resolve the issues that were raised or could have been raised by all parties to this proceeding.

SETTLEMENT TERMS

The following terms comprise the Settlement Agreement reached by the Settling Parties:

I. Approval to Develop and Deploy Certain Distributed Intelligence Capabilities of the Advanced Meter

A. The Settling Parties agree that the AGIS CPCN should be amended to reflect that DI capabilities of the advanced meters selected by the Company (the "Advanced Meters") can further enhance the benefits to the Company's distribution operations as well as customer energy management and system emissions reduction benefits that the Commission-approved AGIS Initiative provides; and, therefore, that development and deployment of certain capabilities, described below, is reasonable and in the public interest.

B. The Settling Parties agree that the Company's decision to procure the Advanced Meters which utilize a Wi-Fi radio and the IEEE 2030.5 meter function set communications protocol, and to provide Home Area Network ("HAN") capability pursuant to Section II, is reasonable and prudent.

C. With respect to meter investment, the Settling Parties agree that the presumption of prudence of cost recovery from the AGIS CPCN applies solely to the costs of the meter investment and not to other costs associated with the development and/or deployment of DI capabilities.

D. The Settling Parties agree that, upon a final Commission decision in this proceeding, the Company will deploy Grid-Facing DI Capabilities in the normal course of business, meaning that a CPCN or other pre-approval is not required for such activities.

1. For purposes of this Settlement Agreement:

   a. "Grid-Facing DI Capabilities" are those solutions or services enabled or supported by DI that are for the benefit of the Company's ownership, management, and maintenance of its distribution facilities on the Company's side of the meter. Examples of Grid-Facing DI Capabilities include functions in the areas of location awareness, high impedance detection, power theft detection, secondary equipment assurance, transformer load management, feeder phase balancing, outage detection, and voltage monitoring and optimization.

      1. "EV Load Disaggregation Pilot" – consistent with the Partnerships, Research, and Innovation ("PRI") portfolio of the Company's Commission-approved 2021-2023 Transportation Electrification Plan ("TEP")[1], the Settling Parties agree that the Company may perform load disaggregation on the Advanced Meter for the purpose of the research pilot contemplated in the TEP,[2] provided that the pilot participants (i.e.,

[1] Proceeding No. 20A-0204E, *In the Matter of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan*.

[2] Public Service Company of Colorado Transportation Electrification Plan 2021-2023, filed April 1, 2021, page 43, "Use Disaggregation Analytics to Identify EV Charging."

customers) provide their consent to do so and disaggregation is limited to the detection and disaggregation of electric vehicle ("EV") load and not other load types. The Company will implement the EV Load Disaggregation Pilot through the 60/90-day notice process approved in the TEP, and all PRI requirements established by the Commission in the TEP (e.g., reporting requirements, 30 percent budgeted for income qualified and/or disproportionately impacted communities) shall apply. The Company will identify the project scope in its Distribution System Plan filing, to be filed by May 1, 2022 (see Section VI(B)(2)). Nothing in this Settlement Agreement limits Staff's ability to file a Notice of Deficiency in the 60/90-day notice process, as approved by the Commission in the TEP. The EV Load Disaggregation Pilot shall be entirely funded through the Commission-approved PRI budget. Information from this load disaggregation research activity will be used to support marketing and grid planning efforts, as identified in the approved TEP; however, the Company will not directly market to customers in this research pilot.

b. "Customer-Facing DI Capabilities" are those solutions and services enabled or supported by Load Disaggregation Capabilities on Advanced Meters, which provide analytical disaggregation of electric load inside the premise into end uses. Customer-Facing DI Capabilities expressly excludes solutions and services enabled or supported by analytical disaggregation of electric load through: 1) interval data recording at 5-minute or 15-minute intervals; and, 2) one-second or greater HAN data, which capability is described in Section II below.

c. "Load Disaggregation Capabilities on the Advanced Meter" means the application of analytical tools through the Advanced Meter to a customer's information to determine the loads within the customer's premise. Load Disaggregation Capabilities on the Advanced Meter does not include analysis of customer data available to the Company through methodologies other than the use of the DI Capabilities of the Advanced Meters, including, but not limited to, the information presently available to the Company and information made available in an open and non-discriminatory manner through this Settlement Agreement.

E. The Company may develop and deploy Grid-Facing DI Capabilities in the normal course of business as further described in Section I(F) below. The

Company may develop and deploy the EV Load Disaggregation Pilot through the Commission-approved TEP and recover the costs through the Transportation Electrification Plan Adjustment ("TEPA") rider. As for Customer-Facing DI Capabilities, including Load Disaggregation on Advanced Meters beyond the EV Load Disaggregation Pilot, due to concerns regarding fair competition with unregulated energy services, customer privacy, customer consent, and compliance with the Commission's customer data rules, the Settling Parties agree those DI capabilities should be addressed by the Commission on a case-by-case or programmatic basis in future applications prior to deployment. The Company is prohibited from cost recovery and deploying Customer-Facing DI Capabilities unless and until the Company receives approval from the Commission after filing an application. Such application by the Company shall address at a minimum the following topics (and such information may be filed as Highly Confidential Information should it meet the requirements):

1. The Customer-Facing Di Capability(ies) the Company is requesting be deployed;
2. Costs and benefits;
3. Deployment timelines;
4. Identification and treatment of any revenues, including revenue sharing with customers, as applicable;

5. The detailed nature of the customer insights derived from Load Disaggregation on Advanced Meters that the Company seeks to develop and use;
6. A discussion with respect to how the Company has complied with the Commission's rules regarding the privacy, security, and use limitations for customer data provided to agents of the Company;
7. How customers provide their consent prior to the customer insights being derived, including any applicable Commission Rule waivers requested to enable electronic consent;
8. Whether and how customers can access the customer insights generated by the Company;
9. Whether and how customers can direct the Company to share customer insights generated by the Company with customer-selected third parties;
10. Disclosures of the Company's and/or Xcel Energy, Inc.'s ("Xcel Energy") regulated and unregulated affiliates' ownership interest in the proposed application/solutions, if any;
11. Anticipated meter memory and CPU utilization of the requested load disaggregation or other applications that would run on the meter;
12. Measures that the Company will employ to ensure that the DI Capabilities are implemented in an open and competitive manner and that access to customer data is provided in an easy, non-discriminatory manner;

13. Potential impacts on the competitive market for similar services; and,
14. How the application and the treatment of customer data or insights generated comply with the Commission's customer data rules.

F. To effectuate the intent of the Settling Parties on a precedential basis, the Settling Parties agree to jointly request findings (e.g., specific order points) in the Commission decision in this proceeding as follows:

1. As of the final Commission decision in this proceeding, the Company may deploy Grid-Facing DI Capabilities, including the deployment of DI applications to the meters and the related development investments in doing so, in the normal course of business and that a CPCN or other pre-approval is not required for such activities.
2. As of the final Commission decision in this proceeding, the Company may implement the EV Load Disaggregation Pilot through the 60/90-day notice process approved in the TEP, including the deployment of DI applications to the meters and the related development investments, consistent with the example described as "Disaggregation Analytics to Identify EV Charging" in the Commission-approved PRI portfolio of its TEP, and recover the pilot costs in the TEPA.

II. <u>HAN Deployment and Data Rules</u>

A. The Settling Parties agree that development and deployment of the HAN functionality of the Advanced Meters in an open, non-discriminatory manner (as described below) is in the public interest. Customers' easy access to their energy usage is in the public interest. The Settling Parties agree that the prohibition on Public Service's activities surrounding HAN deployment should be lifted by the Commission's decision approving the Settlement Agreement in this proceeding.

B. The Settling Parties agree that the IEEE 2030.5 meter function set utilizing Itron's HAN application preloaded on the advanced meter has specific functions for the sharing of data with an interval of one second or greater, and could, therefore, be used for the sharing of such data via the HAN, provided there is customer authentication and authorization.

C. The Settling Parties support the deployment of the Company's HAN mobile application for both Android and iOS devices because it allows the Company to test, deploy, and improve the process for connecting meters to customers' HANs. The Settling Parties agree that the application will initially be limited to giving customers one-second kilowatt ("kW") and five-second kilowatt-hour ("kWh") reads until such time as the capabilities provided in subsection (D) below are implemented by Public Service, at which time the Company will be permitted to further develop its HAN application(s) in a manner consistent with the settlement terms herein.

D. The Company agrees to deploy Bring Your Own Device ("BYOD") functionality to allow IEEE 2030.5-compliant devices to connect to the Advanced Meter via a two-step authentication process within 180 days after the Commission's final decision approving the Settlement Agreement in this proceeding. The Settling Parties agree that BYOD means that Wi-Fi-compatible devices running an application that complies with the requirements of the relevant IEEE 2030.5 protocol function set(s) actually implemented by the Company (i.e., that the data available to third parties and the Company is that for which the meters and relevant HAN applications installed by the Company are configured to provide) can, with customer authorization, have access to such data. However, the Company does not guarantee the success of any given HAN connection stemming from factors outside of its control, as discussed in subsection (E) below. In order to facilitate BYOD, the Company agrees to make a Software Development Kit ("SDK") available to developers free of charge under a BSD license (or similar license that allows for the reuse of the source code contained in the SDK without royalty or other restriction).

E. The Settling Parties acknowledge and agree that the Company is not responsible for a variety of factors that can impact the HAN connection and the operation of hardware and software connecting to the advanced meter via the HAN, as the Company does not own or control customers' Wi-Fi or their home internet connections. Accordingly, the Settling Parties agree that the Company is not guaranteeing the success of individual connections to the advanced meter via the HAN and agree to a minor revision to Tariff Sheet R87 as set forth in the paragraph below. Notwithstanding the foregoing, the Company will use reasonable and prudent efforts in accordance with Good Utility Practice (as that term is generally understood in the utility industry) to reasonably ensure that its implementation of IEEE 2030.5 in all advanced meters will operate continuously in accordance with the relevant IEEE 2030.5 protocol function set(s) when under ideal Wi-Fi operating conditions, and the Company agrees to repair or replace meters with HAN defects in a timely manner, consistent with its general operations and maintenance protocols for meter repair and replacement, and provide customer support to assist customers in attempting to successfully establish connections to the meters using the HAN; provided, however, that such support will not require the Company to re-locate meters or take responsibility for factors outside of its ownership and control.

F. The Settling Parties agree that the following sentences should be added to Sheet No. R87 of the Company's Electric Tariff: "The Company shall not be liable for any monetary loss or physical damage resulting from any loss of, diminished quality of, or interruption to data regarding Customer's energy consumption stemming from causes beyond the Company's control." Public Service will file a compliance tariff advice letter on not less than two (2) days' notice within fourteen (14) days of a final Commission decision in this matter to effectuate the tariff addition provided for in this sub-section.

G. The Company agrees to conduct customer outreach and education regarding the HAN capability generally consistent with the Advanced Grid Education Plan filed in Proceeding No. 16A-0588E. Such outreach will describe the BYOD capability generally, and will not narrowly focus on the Company's HAN mobile application.

H. If the Company makes updates to IEEE 2030.5 functionality or function sets over time that are not reverse compatible, the Company shall provide at least 180-days advance notice to affected customers and shall make best efforts to communicate the upcoming change to affected HAN device and software makers. Such notice shall include information necessary for adapting HAN device or software to the modifications.

III. Third-Party Access to Data of One Second of Resolution

A. The Company will provide an SDK with appropriate documentation including code examples and a working sample set of software sufficient to allow a third-party developer to implement either a hardware or software solution that will allow a customer-approved external third party located remotely from the customer premise to access the one-second data measured by the meter via its existing IEEE 2030.5 interface. This initial SDK will be made publicly available at no cost to any interested party no later than 180 days after a Commission final order in this proceeding under a BSD license (or similar license that allows for the reuse of the source code contained in the SDK without royalty or other restriction). This SDK shall be in addition to the one provided for in Section II(D) above. In addition, the Company commits to providing:

1. Up to 2,000 man-hours of technical support in total on a first-come, first-serve basis, to third parties in support of SDK; and,
2. In order to support third-party developers, the Company will conduct at least four (4) workshops for developers within 180 days of the final decision approving the Settlement Agreement in this Proceeding.

IV. Data Delivery Study

A. The Company will study the feasibility, costs, benefits, security implications, and other attributes of the various technical options to deliver one-second timestamped data, including, but not limited to, power, energy, voltage, volt-amps reactive data; applicable rate; meter identifier; and disaggregation insight data to customer-authorized third parties legally permitted to receive such data. The Company will meet with stakeholders early in the study development process and have at least two other meetings prior to the study's completion and a reasonable opportunity for stakeholders to provide feedback on the draft report prior to submittal to the Commission. Such study will include, but not be limited to, evaluating the direct upload functionality as described in Mr. Michael E. Murray's and Dr. David A. Wheeler's testimony.[3] Such study shall also evaluate the feasibility, costs, benefits, security implications, and other attributes of the various technical options available for providing sub-second voltage, current, power and VAR data from the meter to local and internet-based devices or services. Following completion of the study, the Company shall, within one (1) year of a final decision in this proceeding, file a report with the findings of the study and discussion of the options considered. Within six (6) months of filing such report, the Company will file an application consistent with Rule 3002(a)(xix) of the Commission's Electric Rules to submit the Company's

[3] Hearing Exhibit 301 Rev. 1, Answer Testimony of Michael Murray for Mission:data Coalition (Dec. 3, 2021) at 49:8 – 51:6; Hearing Exhibit 300 Rev. 1, Answer Testimony of Dr. David A. Wheeler for Mission:data Coalition (Dec. 3, 2021) at 8:17 – 9:21, 10:7 – 11:9, 11:17 – 12:8, 13:11 – 14:10, 15:1 – 17:2.

recommendation, which could include the request for implementing its recommendation. The filing should also address:

1. Easy, open, non-discriminatory access for customer-authorized third parties;
2. Data parity between the Company and customers;
3. The reasonable terms and conditions under which customer-authorized third parties are eligible; and,
4. The detailed customer authorization process and user experience.

Notwithstanding the foregoing, the Company's application pursuant to this Section IV need not advocate nor propose any particular method or methods to implement any particular outcome.

V. <u>Green Button Connect My Data</u>

A. Within 30 days following a final order in this proceeding, the Company agrees to modify the Green Button Connect ("GBC") terms and conditions that appear on the Company's website as follows:

   1. The language contained in Section 9 will be replaced with the following: "You represent that you have, and will retain, reasonable technical ability to communicate and be interoperable with Xcel Energy's GBC services."

B. The Settling Parties retain their ability to challenge GBC terms that appear on the Company's website outside of this proceeding.

VI. <u>Reporting Requirements</u>

A. The Settling Parties agree that ongoing reporting and Commission oversight over deployment of DI functionality is important and necessary.

At the same time, the Settling Parties recognize that Public Service must maintain a degree of autonomy to develop and deploy Grid-Facing DI Capabilities in order to manage its grid effectively.

B. The Company agrees to provide the following information regarding Grid-Facing DI Capabilities and the EV Load Disaggregation Pilot:

1. The Company commits to including a description of the Grid-Facing DI Capabilities that it intends to deploy in its Distribution System Plan ("DSP") filings. However, the Settling Parties agree that the Company is not required to obtain Commission approval prior to deployment of Grid-Facing DI Capabilities, and that such deployments may be performed in the normal course of business. The Settling Parties acknowledge that any costs associated with such Grid-Facing DI Capabilities will be made in the normal course of business with prudence and cost recovery to be determined in a future cost recovery proceeding.

2. The Company will provide the following details in its DSP, to be filed by May 1, 2022: 1) project estimate and goals; 2) an estimate for participants and budget; 3) a summary of the application process; 4) projected benefits; 5) pilot-specific policies; 6) a summary of stakeholder involvement; and, 6) a discussion of the evaluation, measurement, and verification approach. Further, the Company will file a report on the EV Load Disaggregation Pilot initiated during the 2021-2023 TEP with the Company's 2024-2026 TEP. As relevant,

this report will include items listed in Sections VI(D)(1)(a), (b), and (c) as well as describe the lessons learned and how they are incorporated into designing new electric vehicle programs.

C. Before deploying Customer-Facing DI Capabilities, the Company must file an application consistent with Section I(E) above, while also providing notice of such application to intervenors in this proceeding and to those on the service list of its most recent Distribution System Plan ("DSP").

D. The Company agrees to provide the following information regarding Grid-Facing DI Capabilities and Customer-Facing DI Capabilities:

1. On an annual basis within the DSP proceeding, the Company will file the following retrospective reporting information about DI Capabilities to date:

    a. A list of all applications deployed on meters including:

        i. Name of the application;
        ii. Author, creator, or licensor(s) of the application;
        iii. The program or use case that the application supports;
        iv. A description of the application and the process whereby it was selected;
        v. The number of meters on which the application is deployed, grouped by customer class;
        vi. Whether the application is utility-facing, customer-facing, or both;

vii. If the application is customer-facing, an explanation and/or screenshots showing how customers initiate, use, and/or benefit from the application;

viii. A description of where customer data and resulting insights are transmitted and held;

ix. Whether and how the application creator or licensor(s) are entitled to access or use customer data or insights for any purpose; and,

x. Whether the application uses sub-second data.

b. Estimated typical and maximum remaining memory and processing power available to host Grid-Facing DI Capabilities and Customer-Facing DI Capabilities, respectively, as a percentage of total;

c. An accounting of the costs incurred through DI Capabilities to date;

d. A discussion of the benefits delivered to customers through the available DI Capabilities to date (including but not limited to energy savings and load reductions); and,

e. A list of DI applications that have been uninstalled or terminated in any manner, and a description of the circumstances.

2. As part of its biannual DSP, the Company will also provide the following prospective information:

a. A non-binding description of the Company's plans for developing Customer-Facing and Grid-Facing DI Capabilities in the next two years, including the expected benefits and timelines for these capabilities.

3. To facilitate transparency with regards to distribution system planning, the Company commits to hosting at least one stakeholder meeting per year regarding its development of Grid-Facing DI Capabilities that are in the normal course of business. During this meeting, the Company will provide information on the applications that the Company is developing, describe anticipated costs and benefits, describe anticipated procurement process and timeline, and receive stakeholder feedback and ideas for potential Grid-Facing DI Capabilities.

E. Xcel Energy commits to establishing guidelines to help ensure that unregulated affiliates or any unregulated offerings of the Company itself will not obtain preferential treatment compared to non-affiliated third parties by the Company for the use of DI. These guidelines will include:

1. Xcel Energy's and the Company's unregulated affiliates will only be allowed to access data and insights from the advanced meters to the extent that the same data is available to similarly situated third parties, and with customer consent; and,

2. The Company will not deploy DI Capabilities for unregulated services.

F. The Company may create, update, maintain, or enhance DI Capabilities in-house at their own discretion, particularly when it is cost-effective. If the Company chooses to conduct a solicitation for new DI Capabilities that are materially different from existing capabilities, however, the solicitation should be competitive in nature. The Company may forgo a competitive solicitation and utilize pre-existing vendor relationships when procuring application maintenance functions, providing enhancements or updates to existing applications, or executing an existing scope of work.

VII. Cost Recovery

A. The Settling Parties agree that the Company is not seeking recovery of the costs of deploying DI capabilities in this Proceeding but, rather, the Company will seek cost recovery for the incremental costs of DI development and deployment in other cost recovery proceedings. The incremental costs of DI are those costs to develop the foundational capabilities and the deployment of DI use cases presented in the Direct Testimony of Company Witness Mr. Romine.

B. The Settling Parties agree that the costs of Grid-Facing DI Capabilities, if determined to have been prudently incurred, are appropriate for recovery in base rates, and that the costs of Customer-Facing DI Capabilities should be considered on a case-by-case or programmatic basis for recovery through appropriate cost recovery venues or mechanisms.

C. The Settling Parties agree that the costs to the Company of carrying out the commitments of Sections II and IV (including the costs of preparing and prosecuting the application contemplated by Section IV) may be deferred in a regulatory asset without carrying costs and the Company will propose the appropriate amortization of recovery of such regulatory asset in a cost recovery proceeding. No presumption of prudence will apply to such costs as a result of this proceeding. Such deferred costs shall not exceed $2.5 million.

VIII. General Provisions

A. This agreement is made for settlement purposes only. No Settling Party concedes the validity or correctness of any regulatory principle or methodology directly or indirectly incorporated in this Settlement Agreement. Furthermore, this Settlement Agreement does not constitute agreement, by any Settling Party, that any principle or methodology contained within or used to reach this Settlement Agreement may be applied to any situation other than the above-captioned Proceeding, except as expressly set forth herein. No binding precedential effect or other significance, except as may be necessary to enforce this Settlement Agreement or a Commission order concerning the Settlement Agreement, shall attach to any principle or methodology contained in or used to reach this Agreement, except as expressly set forth herein.

B. The Settling Parties agree the provisions of this Settlement Agreement, as well as the negotiation process undertaken to reach this Settlement Agreement, are just, reasonable, and consistent with and not contrary to the public interest, and should be approved and authorized by the Commission.

C. The discussions among the Settling Parties that produced this Settlement Agreement have been conducted in accordance with Rule 408 of the Colorado Rules of Evidence.

D. Nothing in this Settlement Agreement shall constitute a waiver by any Settling Party with respect to any matter not specifically addressed in this Settlement Agreement.

E. The Settling Parties agree to use good faith efforts to support all aspects of the Settlement Agreement embodied in this document in any hearing conducted to determine whether the Commission should approve this Settlement Agreement, and/or in any other hearing, proceeding, or judicial review relating to this Settlement Agreement or the implementation or enforcement of its terms and conditions. Each Settling Party also agrees that, except as expressly provided in this Settlement Agreement, it will take no formal action in any administrative or judicial proceeding that would have the effect, directly or indirectly, of contravening the provisions or purposes of this Settlement Agreement. However, except as expressly provided herein, each Settling Party expressly reserves the right to advocate positions different from those stated in this Settlement Agreement in any proceeding other than one necessary to obtain approval of, or to implement or enforce, this Settlement Agreement or its terms and conditions.

F. The Settling Parties do not believe any waiver or variance of Commission rules is required to effectuate this Settlement Agreement but agree jointly to apply to the Commission for a waiver of compliance with any requirements of the Commission's Rules and Regulations if necessary to permit all provisions of this Settlement Agreement to be approved, carried out, and effectuated.

G. This Settlement Agreement is an integrated agreement that may not be altered by the unilateral determination of any Settling Party. There are no terms, representations, or agreements among the parties which are not set forth in this Settlement Agreement.

H. This Settlement Agreement shall not become effective until the Commission issues a final decision addressing the Settlement Agreement. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Settling Party, that Settling Party may withdraw from the Settlement Agreement and shall so notify the Commission and the other Settling Parties in writing within ten (10) days of the date of the Commission order. In the event a Settling Party exercises its right to withdraw from the Settlement Agreement, this Settlement Agreement shall be null and void and of no effect in this or any other proceeding.

I. There shall be no legal presumption that any specific Settling Party was the drafter of this Settlement Agreement.

J. In agreeing to this Settlement Agreement, Itron does not become a regulated entity subject to Commission regulation, nor does it take on any obligations of the regulated entity, Public Service.

K. This Settlement Agreement may be executed in counterparts, all of which when taken together shall constitute the entire Agreement with respect to the issues addressed by this Settlement Agreement. This Settlement Agreement may be executed and delivered electronically and the Settling Parties agree that such electronic execution and delivery, whether executed in counterparts or collectively, shall have the same force and effect as delivery of an original document with original signatures, and that each Settling Party may use such facsimile signatures as evidence of the execution and delivery of this Settlement Agreement by the Settling Parties to the same extent that an original signature could be used.

Dated this 18th day of February, 2022.

Agreed on behalf of:

PUBLIC SERVICE COMPANY OF COLORADO

By: *__/s/ Brooke A. Trammell____________*
Brooke A. Trammell
Regional Vice President,
Rates and Regulatory Affairs
Xcel Energy Services Inc.

Approved as to form:

By: *__/s/ Elizabeth C. Stevens____________*

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ITRON, INC.

By: ______________________
Donald L. Reeves

Its: Senior Vice President, Itron Outcomes

Approved as to form:

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COLORADO SOLAR AND STORAGE ASSOCIATION

By: _Mike Kruger__

Its: President and CEO

SOLAR ENERGY INDUSTRIES ASSOCIATION

By: ______________________________

Its: _Sr Director, Western States, SEIA__

Approved as to form:

By: ______________________________

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MISSION:DATA COALITION, Inc.

By: Michael E. Murray

Michael E. Murray

Its: President

Approved as to form:

By: Victoria R. Mandell

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By: */s/ Eric R. Haglund*

Its: Senior Economist

Approved as to form:

By: */s/ Kristine A. K. Roach*

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By: *__/s Cindy Z. Schonhaut__________*

Its: __Director____________________

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UTILIDATA, INC.

By: ______________________
Lauren Randall

Its: Vice President, State Policy & Regulatory

Approved as to form:

By: ______________________

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Please note that the Company is filing live spreadsheets for Attachments M, N, and O.

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

Xcel Energy Response to Request for Information: Executive Order 22-20 Implementation for Electric Rate-Regulated Utilities in Minnesota
April 3, 2023

Background
The following questions were taken from NARUC's *Understanding Cybersecurity Preparedness: Questions for Utilities* guide, a companion resource to its Cybersecurity Strategy Development Guide, and are intended to provide the Department with a better understanding of the methodologies and strategies utilities are currently using to guarantee the security of their cyber systems. This information will be used to ascertain the type and quality of information currently available to the Commission and whether existing self-assessment and compliance reporting requirements satisfy the requirements of the directives in EO 22-20. Please provide a response to the following questions regarding your company's cyber security practices for IT/OT systems NOT covered by NERC CIP-002 through CIP-014:

1. **Do you have a cyber risk management program? If so, is this based on a cybersecurity framework, and is the program integrated into overarching enterprise risk management?**

   Response

   Xcel Energy does have a cyber risk management program. This program is multifaceted and partners with each Xcel Energy business area to assess their respective cyber-physical risk postures. The assessments are based both on the National Institute of Standards and Technology (NIST) Cyber Security Framework (CSF) and the Xcel Energy Enterprise Security Standards. Teams within the Business Security Risk and Support Services (BSRASS) organization perform the assessments at regular intervals. The enterprise risk management objectives are informed by the referenced cyber risk management program.

2. **Have you written and implemented a cybersecurity policy, strategy, or similar governance document? If yes, is it reviewed and/or audited regularly?**

<u>Response</u>
Xcel Energy has an overarching governance policy and OT Enterprise Security Standards. The Security Standards cover 14 security domains. This policy is formally reviewed every two years and standards are reviewed at a minimum annually.

3. **Does your company include cybersecurity requirements for IT and OT assets in procurement contract language?**

<u>Response</u>
Xcel Energy has a procurement process that includes cyber security requirements for both "IT" and "OT" assets. For example, the contract language includes, but is not limited to addendums covering:

i. Product Documentation
ii. Incident Reporting
iii. Vulnerability Notification
iv. Risk Assessments
v. Background Checks
vi. Access Controls

4. **Do you have a vulnerability or patch management plan?**

<u>Response</u>
Xcel Energy has both vulnerability and patch management programs that span across IT and OT. The requirements of these programs are outlined in the Enterprise Security Emergency Management (ESEM) Enterprise Security Standards and cover the creation of specific vulnerability and patching plans based on asset type, location, and criticality of vulnerability. In practice, each business unit is responsible for their respective patch and vulnerability management processes and plans. Our plans ensure we meet our regulatory compliance obligations for NERC CIP and TSA Security Directives where applicable.

5. **Do you have cyber incident response policies and contingency plans in place for minimizing the effects of a cyber incident? Do these plans include the use of alternative methods for meeting critical functions in the absence of IT or communications technology?**

Response
Xcel Energy has numerous cyber incident response and operational contingency plans currently in place. There is a core Cyber Security Incident Response Team Plan (CSIRT), followed by situationally specific response plans maintained by both ESEM and relative operations business partners. Additionally, planning for the operational resilience of critical functions reflects an all-hazards approach. This includes, but is not limited to, risks that face the company via, cyber, physical, environmental, and supply-chain vectors. Xcel Energy recognizes the risk an interconnected grid represents and is actively planning for the resilient delivery of critical services for its customers. Alternative methods to meet critical functions where communications have been impacted is one of the considered scenarios.

6. **Do you have lists of identified points of contact for cybersecurity issues?**

Response
Xcel Energy has a documented list of stakeholder points of contact in both the CSIRT and an Incident Response Stakeholders list. These lists include internal POCs across all business areas as well as external agencies (CISA, NCCIC, EISAC, etc.)

7. **Have recovery activities been consolidated into formal continuity and recovery plans?**

Response
Xcel Energy's Enterprise Command Center uses cyber playbooks to respond to events and initiate recovery plans. In addition, there are Disaster Recovery Plans that are specific to applications (within each business area). These Plans are mapped to the respective department level Business Continuity Plans. At this time, we do not consider these activities implemented into a fully "formalized" plan(s). As with all plans and programs, we are investing in continuous improvement and evolution to keep ahead of risks and threats.

8. **Additionally, from the resources provided by the Minnesota Fusion Center above, please indicate which of the following resources are currently used by your company in implementing and monitoring the cyber threat landscape for those assets not covered by NERC CIP-002 through CIP-014.**

Response
Xcel Energy uses the following resources:

- National Institute of Standards and Technology (NIST) Cybersecurity Framework
- Application of practices defined in NERC CIP Standards to distribution information systems

Xcel Energy may leverage the following resources during monitoring designs:

- Department of Energy Cybersecurity Capability Maturity Model (C2M2)
- Electric Power Research Institute (EPRI) Security Architecture for the Distributed Energy Resources Integration Network
- National Renewable Energy Laboratory (NREL) Guide to the Distributed Energy Resources Cybersecurity Framework

9. Also, if there are other resources used by subject matter experts at your company, please list and briefly describe?

Response

From an Xcel Energy Threat Intelligence/Government partnership perspective:

- We are registered with the MNFC and have contacts there for reporting. We are also on their communication distribution list.
- We are registered with our industry ISACs and regularly receive and share information (which the MNFC gets alerts on)
- We participate in the Midwest Reliability Organization (MRO) Security Advisory Council (SAC) and Threat Forum (SACTF)
- We are members of the CISA Cybersecurity Information Sharing Collaboration Program (CSISC) program as well as the Joint Cyber Defense Collaborate (JCDC) for our region
- We are pilot members of DOE's Energy Threat Analysis Center (ETAC)
- We are registered with DHS Surface Information Sharing Cell (SISC) Intel program

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NOS. E002/M-21-694
E002/M-21-630
Miscellaneous Electric Service List

Dated this 1st day of November 2023

/s/
____
Ella Giefer
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, MN 55405	Electronic Service	No	OFF_SL_21-694_21-694
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_21-694_21-694
Jay	Anderson	jaya@cmpas.org	Central Minnesota Municipal Power Agency	7550 Corporate Way Suite 100 Eden Prairie, MN 55344	Electronic Service	No	OFF_SL_21-694_21-694
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_21-694_21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Janet	Brown	jab5100@gmail.com	Sabathani Community Center (Sabathani/SCC)	310 E 38th St Ste 200 Minneapolis, MN 55409	Electronic Service	No	OFF_SL_21-694_21-694
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	60 S 6th St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_21-694_21-694
LORI	CLOBES	lclobes@mienergy.coop	MiEnergy Cooperative	31110 COOPERATIVE WAY PO BOX 626 RUSHFORD, MN 55971	Electronic Service	No	OFF_SL_21-694_21-694
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-694_21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_21-694_21-694
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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	Electronic Service	No	OFF_SL_21-694_21-694
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-694_21-694
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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