APPENDIX A: COMPLIANCE MATRIX

Xcel Energy is committed to complying fully with all applicable statutes, rules and orders. We believe our 2024-2040 Upper Midwest Integrated Resource Plan reflects appropriate implementation of all related requirements. The matrix below reflects our inventory of requirements to be met in the 2024-2040 Upper Midwest Integrated Resource Plan and cross-references to the portion of the IRP that fulfills each compliance item.

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Minn. Stat. § 216B.1691 Renewable Energy Objectives	Subdivision 2a	**Eligible energy technology standard**. Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from an eligible energy technology that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated: (1) 2012 12 percent (2) 2016 17 percent (3) 2020 20 percent (4) 2025 25 percent (5) 2035 55 percent	Appendix N: Standard Obligations
Minn. Stat. § 216B.1691 Renewable Energy Objectives	Subdivision 2e	**Rate impact of standard compliance; report**. Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. In consultation with the Department of Commerce, the commission shall determine a uniform reporting system to ensure that individual utility reports are consistent and comparable, and shall, by order, require each electric utility subject to this section to use that reporting system. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. A report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422. The reporting obligation of an electric utility under this subdivision expires December 31, 2040.	Chapter 6: Customer Rate and Cost Impacts
Minn. Stat. § 216B.1691 Renewable Energy Objectives	Subdivision 2g	**Carbon-free standard.** In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated: (1) 2030 - 80 percent for public utilities; 60 percent for *other* electric utilities (2) 2035 - 90 percent for all electric utilities (3) 2040 -100 percent for all electric utilities.	Appendix N: Standard Obligations
Minn. Stat. § 216B.1691 Renewable Energy Objectives	Subdivision 3a	**Utility plans filed with commission**. (a) Each electric utility shall report on its plans, activities, and progress with regard to the standard obligations under this section in its filings under section 216B.2422, or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of: (1) the status of the utility's renewable energy mix relative to the standard obligations; (2) efforts taken to meet the objective and standard obligations; (3) any obstacles encountered or anticipated in meeting the standard obligations; and (4) potential solutions to the obstacles. (5) the number of Minnesotans employed to construct facilities designed to meet the utility's standard obligations under this section; (6) efforts taken to retain and retrain workers employed at electric generating facilities that the utility has ceased operating or designated to cease operating for new positions constructing or operating facilities used to meet a utility's standard obligation; (7) the impacts of facilities designed to meet the utility's standard obligations under this section on environmental justice areas; (8) efforts made to increase the diversity of both the utility's workforce and vendors; and (9) for an electric utility utilizing renewable energy credits to satisfy any portion of its obligations under this section, the following information: (i) the name and location of energy facilities that generated the energy associated with the credits; (ii) the dates when the energy associated with the credits was generated; (iii) the type of fuel that generated the energy associated with the credits; and (iv) whether the energy associated with the credits was purchased by the utility purchasing the credits.	Appendix N: Standard Obligations

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Minn. Stat. § 216B.1691 Renewable Energy Objectives	Subdivision 10	A competitive resource acquisition process established by the commission prior to June 1, 2007, shall not apply to a utility for the construction, ownership, and operation of generation facilities used to satisfy the requirements of this section unless, upon a finding that it is in the public interest, the commission issues an order on or after June 1, 2007, that requires compliance by a utility with a competitive resource acquisition process. A utility that owns a nuclear generation facility and intends to construct, own, or operate facilities under this section shall file with the commission as part of the utility's filing under section 216B.2422 a renewable energy plan setting forth the manner in which the utility proposes to meet the requirements of this section	N/A - we are not proposing any specific resource acquisitions in this Resource Plan
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 2	(c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.	Chapter 5: Economic Modeling Framework
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 2a	**Historical data and Advance Forecast.** Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Appendix AA: 2022 Electric Utility Annual Report
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 2c	**Long-range emission reduction planning.** Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.	Chapter 2: Planning Landscape Chapter 4: Preferred Plan Appendix K: Environmental Regulations Review Appendix T: MISO Grid Congestion
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 3	**Environmental Costs**. (a) A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 3(a)	**Environmental costs.**(a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs Appendix K: Environmental Regulations Review
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 4	**Preference for renewable energy facility.** The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the commission must consider: (1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.; (2) impacts on local and regional grid reliability; (3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and (4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 4a	**Preference for local job creation**. As part of a resource plan filing, a utility must report on associated local job impacts and the steps the utility and the utility's energy suppliers and contractors are taking to maximize the availability of construction employment opportunities for local workers. The commission must	Appendix O: 2023 Workforce Transition Plan Summary Appendix O1: 2023 Workforce Transition Plan Appendix R: Equity
Minn. Stat. § 216B.2422 Resource Planning; Renewable Energy	Subdivision 7	**Energy storage systems assessment.** (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to: (1) meeting identified generation and capacity needs; and (2) evaluating ancillary services. (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).	Appendix F: EnCompass Modeling Assumptions & Inputs Appendix H: Resource Options Appendix I: Minnesota Energy Storage Systems Assessments Appendix L: System Planning Integration
Minn. Stat. § 216B.2426 Opportunities for Distributed Generation		The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.	Chapter 5: Economic Modeling Framework
Minn. Stat. § 3.8851 Legislative Energy Commission	Subdivision 4	**Nuclear reports**. The public utility that owns the Prairie Island and Monticello nuclear generation facilities shall update the reports required under section 116C.772, subdivisions 3 to 5, and shall submit those updates periodically to the Public Utilities Commission with the utility's resource plan filing under section 216B.2422 and to the Legislative Energy Commission.	Appendix M: Nuclear Appendix BB: 2022-2024 Triennial Nuclear Plant Decommissioning Study and Assumptions

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Minn. Rule 7843.0300 Filing Requirements and Procedures	Subpart 3	**Completeness of filing.** The resource plan must contain the information required by part 7843.0400, unless an exemption has been granted under subpart 4.	See below:
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 1	**Advance forecasts.** A utility shall include in the filing identified in Subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the Minnesota Environmental Quality Board under Minnesota Statutes, sections 216B.2422, subdivision 2a, and 216C.17, and parts 7610.0000 to 7610.0600.	Appendix AA: 2022 Electric Utility Annual Report
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 2	**Resource Plan.** A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. Utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. Utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix G: Scenario Sensitivity Analysis--PVRR & PVSC
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 3	**Supporting Information.** A utility shall include in its resource plan filing information supporting selection of the proposed resource plan.	Entire IRP
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 3A	A) When a utility's existing resources are inadequate to meet the projected level of resource needs, the supporting information must contain a complete list of resource options considered for addition to the existing resources. At a minimum, the list must include new generating facility of various types and sizes and with various fuel types, cogeneration, new transmission facilities of various types and sizes, upgrading of existing generation and transmission equipment, life extensions of existing generation and transmission equipment, load-control equipment, utility-sponsored conservation programs, purchases from non-utilities, and purchases from other utilities. The utility may seek additional input from the commission regarding the resource options to be included in the list. For a resource option that could meet a significant part of the need identified by the forecast, the supporting information must include a general evaluation of the option, including its availability, reliability, cost, socioeconomic effects, and environmental effects.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix H: Resource Option
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 3B	B) The supporting information must include descriptions of the overall process and of the analytical technique used by the utility to create its proposed resource plan from the available options.	Chapter 5: Economic Modeling Framework
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 3C	C) The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. Action plan must cover a five-year period beginning with the filing date. Action plan must include a schedule of key activities, including construction and regulatory filings.	Chapter 4: Preferred Plan
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 3D	D) For the proposed resource plan as a whole, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.	Chapter 4: Preferred Plan
Minn. Rule 7843.0400 Contents of Resource Plan Filings	Subpart 4	**Nontechnical summary.** A utility shall include in its resource plan filing a non-technical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills. Minn. Stat. §216B.1612,	Appendix Z: Non-Technical Summary
Docket No. E999/CI-06-159 In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005 **August 10, 2007 Order**	Order Point 2	**(Fossil Fuel Efficiency Standard)** Investor-owned utilities shall include information in their Resource Plans generically describing how the utility is planning to address fossil fuel efficiency to meet the goals of this standard.	Chapter 5: Economic Modeling Framework Appendix F: Encompass Modeling Assumptions & Inputs
Docket No. E999/CI-06-159 In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005 **August 10, 2007 Order**	Order Point 3	Investor-owned utilities shall include information in their Resource Plans with respect to: a. The heat rates of existing plants; b. Their efforts to maintain or improve heat rates over time; and c. Modeling runs(s) of ways to improve the heat rates of either the largest existing or the lowest heat rate generation plants.	Appendix F: EnCompass Modeling Assumptions & Inputs
Docket No. E002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 1	The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, 2f.	Chapter 4: Preferred Plan Appendix N: Standard Obligation
Docket No. E002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan August 5, 2013 Notice	Page 2, Para 1	The Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard.	Chapter 4: Preferred Plan Appendix N: Standard Obligations

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 2, Para 3	Utilities shall consider convening a stakeholder meeting prior to filing their initial IRPs to answer questions about assumptions used in the filing, for the purpose of responding to questions which could enhance parties' understanding of the filing and reducing the number of information requests parties may need to file.	Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 10	10. Xcel shall acquire no less than 400 MW of additional demand response by 2023.	Appendix J: Distributed Energy Resources
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 12	12. Xcel shall investigate the potential for an energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. § 216B.241, subd. 1a(b).	Appendix J: Distributed Energy Resources
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 15	15. In future resource plan filings, analysis and inputs must, to the extent possible, be consistent with Xcel's distribution system planning.	Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 and E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 1	The Commission hereby quantifies and establishes the range of regulatory costs of carbon dioxide emissions as $5 to $25 per short ton effective 2025 and thereafter.	Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs Appendix G: Scenario Sensitivity Analysis--PVRR & PVSC
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 2A2.	2) Xcel shall continue to acquire 400 megawatts of incremental demand response by 2023 as ordered in the company's last resource plan.	Appendix J: Distributed Energy Resources
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 5	5. Xcel shall consider opportunities to deploy renewable resources, storage technologies, and resources powered by hydrogen or clean fuel alternatives on a schedule faster than in its Alternate Plan. If deployment would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies, Xcel shall pursue them.	Chapter 4: Preferred Plan
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 9A	9. Xcel shall take steps to better align distribution and resource planning, including: A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan.	Appendix E: Load and DER Forecasting Appendix L: System Planning Integration
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 9B	B. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool.	Appendix E: Load and DER Forecasting Appendix L: System Planning Integration Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 9C	C. Proactively plan 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.	Appendix E: Load and DER Forecasting Appendix L: System Planning Integration
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 9D	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.	Appendix L: System Planning Integration
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 9E	E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	Appendix L: System Planning Integration

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 10	10. In its next resource plan Xcel shall, either through its Integrated Distribution System Plan proceedings or through another stakeholder process, develop and/or improve its forecasts of the adoption rate for the following technologies, to be used in Xcel's base case scenario and its overall demand forecast. A. Adoption of light-, medium-, and heavy-duty electric vehicles. B. Adoption of electric space heating. C. Adoption of electric water heating. D. Electrification of other end uses. E. Increased potential for demand response and load flexibility from an increase in electrification of the technologies in A–D. F. Adoption of distributed solar-powered generators—including generators sited by customers, community solar gardens organized under Minn. Stat. § 216B.1641, and generators that are neither sited by customers nor related to community solar gardens.	Appendix E: Load and DER Forecasting Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 12	12. Xcel shall include in its next resource plan a deeper analysis of (1) storage options, including options combining solar generation and battery storage, and (2) the role of hydrogen and clean fuel alternatives in Xcel's resource mix. In preparation, Xcel shall work with stakeholders to develop a fair basis for comparing the full supply-chain and life-cycle carbon impacts of the generation and storage resource options under consideration to help the Commission evaluate the "adverse socioeconomic effects and adverse effects upon the environment" of each option, pursuant to Minn. R. 7843.0500, subp. 3.C.	Appendix F: EnCompass Modeling Assumptions & Inputs Appendix H: Resource Options Appendix I: MN Energy Storage Systems Assessment Appendix X: Advanced Technologies Appendix Y: Life Cycle Emissions Impact
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 13	13. In its next resource plan, Xcel shall account for anticipated effects of advanced rate design, demand response, and any other efforts to shift customer demand.	Appendix J: Distributed Energy Resources
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 15A	15. Xcel shall work with stakeholders to develop a modeling construct that enables Xcel, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Xcel and stakeholders shall address the following factors in developing the modeling construct: A. Using a "bundled" approach as is used to model energy efficiency and demand response.	Appendix H: Resource Options Appendix J: Distributed Energy Resources Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 15B	B. The costs borne by the utility and the costs borne by the customer.	Appendix J: Distributed Energy Resources Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 15C	C. Cost effectiveness tests.	Appendix J: Distributed Energy Resources Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 15D	D. Other topics as identified by stakeholders.	Appendix J: Distributed Energy Resources Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 15	Xcel shall include improved load flexibility and demand response modeling methodologies prospectively, including in its next resource plan.	Appendix E: Load and DER Forecasting
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 16	16. In its next resource plan, Xcel shall account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation.	Appendix E: Load and DER Forecasting Appendix V: Community Goals
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 18	18. In its next resource plan filing, Xcel shall include an analysis of rate and bill impacts for the residential, commercial, and industrial classes.	Chapter 6: Customer Rate and Cost Impacts
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20B	B. Xcel shall conduct stakeholder meetings regarding the site with interested parties including the city of Becker; adjacent cities and townships including Becker Township and the city of Monticello; Sherburne and Wright counties; the Minnesota Department of Commerce, the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, the Center for Energy and Environment, the Clean Energy Organizations, the Minnesota Energy Transition Office,41 and labor unions. By January 1, 2023, Xcel shall file in the new docket details describing updates on the site and the stakeholder outreach and meetings.	Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C1	C. Following these stakeholder meetings, by December 31, 2023, or in its next resource plan if earlier—and annually thereafter—Xcel shall submit to the Commission and to the city of Becker a detailed report describing the company's plans for the disposition of the Sherco site, equipment, and buffer property. The report shall include at least the following items: 1) A detailed description and timeline of any demolition, environmental cleanup, or similar work that will be required by the impending retirement of Sherco Unit 2.	Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C2	2) To the extent possible, a description of the company's plans and a detailed timeline to decommission and demolish electric generating equipment related to Sherco Units 1 and 3.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C3	3) A detailed description of the timeline, estimated costs, and steps necessary to remediate pollution at the Sherco site.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C4	4) A section detailing how the company is working to ensure that plans for site remediation, economic development, or future development and maintenance of power generation, transmission, or distribution infrastructure are consistent with the community's long-range planning and vision.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C5	5) A description of any ongoing efforts by the company to evaluate future uses for the plant site, any buffer property owned by the company, or any adjacent property, including a description of how the company is involving interested stakeholders in those efforts.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C6	6) An update to the Commission on the status of efforts to support the city's and region's economic development efforts, including—to the extent possible—specific projects and investments the company is assisting the city and region in attracting.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C7	7) A description of the company's efforts to work with local governments and other stakeholders to assess and account for local land use and planning impacts. Before starting any additional regulatory process to determine the final length and route of the Sherco gen-tie line, Xcel shall consult with stakeholders to discuss the plans.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C8	8) Any other items the Commission or the company sees fit to include.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 20C	If Xcel cannot obtain the necessary information at the time of each filing, the company shall submit a detailed timeline on which it anticipates it will be able to provide the city and stakeholders with additional information.	E002/M-22-263 Appendix P: 2023 Sherco Remediation Report Summary Appendix P1: 2023 Sherco Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21A	21. Regarding remediation plans for the King site: A. The Commission authorizes its Executive Secretary to open a new docket on this topic.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21B	B. Xcel shall conduct quarterly stakeholder meetings regarding the King site with interested parties including the city of Oak Park Heights, Washington County, the Department, DNR, the Energy Transition Office, PCA, the National Park Service, CEOs, CEE, the Wild Rivers Conservancy, and labor unions. Xcel shall file in the new docket by January 1, 2023, details describing the stakeholder outreach and updates for the efficient demolition of the King plant and remediation of the site and impacted land.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C1	C. Following these stakeholder meetings, by December 31, 2023, or in its next resource plan if earlier—and annually thereafter—Xcel shall submit to the Commission, the city of Oak Park Heights, and interested stakeholders a detailed report describing the company's plans for the disposition of the King site, equipment, and buffer property. This report should include the following: 1) The company's plans, estimated costs, and a detailed timeline to decommission and demolish the electric generation facility.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C2	2) A detailed description of the timeline and steps necessary to remediate pollution at the King site.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C3	3) A description of any ongoing efforts by the company to evaluate future uses for the plant site, any buffer property owned by the company, or any adjacent property, including a description of coordination with or involvement of the city and stakeholders in those efforts.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C4	4) The status of efforts to support the region's and city's economic development efforts, including—to the extent possible—specific projects and investments the company is helping the city to attract.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C5	5) An update on conservation efforts to reflect the uniqueness of the site and surrounding property located in and along the St. Croix National Scenic Riverway.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C6	6) Any other items the Commission or the company sees fit to include.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 21C	If Xcel cannot obtain the necessary information at the time of each filing, the company shall submit a detailed timeline on which it anticipates it will be able to provide the city and stakeholders with additional information.	E002/M-22-264 Appendix Q: 2023 King Remediation Report Summary Appendix Q1: 2023 King Remediation Report
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 22	22. Xcel shall immediately begin stakeholder discussions exploring the future of the Prairie Island Nuclear Generating Plant.	Appendix M: Nuclear Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23A	23. In its next resource plan, Xcel shall file a report explaining the following: A. Planned investments at the Prairie Island and Monticello, and future plans for Prairie Island.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23B	B. Any aging management issues that may arise from continued operation.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23C	C. Expectations regarding future nuclear workforce.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23D	D. Cyber-security issues or concerns as plants move from analog to digital systems.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23E	E. True comprehensive cost-benefit analysis, which includes potential environmental and economic impacts to the neighboring communities—in particular, the Prairie Island Indian Community and its Treasure Island Resort & Casino.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23F	F. Additional spent nuclear fuel generated over a 10- or 20-year period.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23G	G. How fuel stored on-site will be removed during the next integrated resource plan period.	Appendix M: Nuclear

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23H	H. Which additional state permits, Certificates of Need, or federal licenses will be required.	Appendix M: Nuclear
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 23I	I. The full supply chain and life-cycle carbon impacts of the ongoing nuclear generation and storage at each of the facilities.	Appendix Y: Life Cycle Emissions Impacts
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 24	24. The Commission authorizes the Executive Secretary to open a new docket regarding workers at retiring generating facilities in Minnesota, including Sherco and King.	E002/M-22-265 Appendix O: 2023 Workforce Transition Plan Summary Appendix O1: 2023 Workforce Transition Plan
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 24A	A. Xcel—working with the Minnesota Department of Employment and Economic Development and the Energy Transition Office; the International Brotherhood of Electrical Workers, Locals 23, 160, and 949; the Minnesota Building Trades; and the Center for Energy and Environment—shall develop a comprehensive plan for supporting transitioning workers. The plan shall consider the measures outlined in the IBEW comments dated March 17, 2020, and March 21, 2021, including skills inventories, training and education, worker placement and potential early retirement buy-out scenarios. Xcel shall file the plan with the Commission no later than December 31, 2022. The plan shall include an estimated budget for each measure, timeline for implementation, and a description of additional funding needed by DEED or the Energy Transition Office, if applicable, to implement the plan.	E002/M-22-265 Appendix O: 2023 Workforce Transition Plan Summary Appendix O1: 2023 Workforce Transition Plan
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 24B	B. Beginning on December 31, 2023, and annually thereafter, Xcel shall file a detailed update on its efforts to implement the plan in coordination with CEE, DEED and the Energy Transition Office, and IBEW.	E002/M-22-265 Appendix O: 2023 Workforce Transition Plan Summary Appendix O1: 2023 Workforce Transition Plan
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25A	25. Xcel shall engage in community outreach and establish a stakeholder group to do the following: A. Design for the equitable delivery of electricity services and programs for energy burdened customers in the company's next resource plan.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25B	B. Create new options to improve customer access to energy efficiency and renewable energy.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25C	C. Draft a plan to be submitted in Xcel's next resource plan to bring the racial and gender diversity of the company's workforce in line with the utility's stated goals.	E002/M-22-266 Appendix R: Equity Appendix R1: Workforce Diversification Plan Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25D	D. Design incentives to ensure that communities of low-income, Black, Indigenous, and People of Color that have disproportionately borne costs of unjust and inequitable energy decisions have equitable access to programs promoting distributed generation.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25E	E. Adopt practices in furtherance of procedural justice—including deeper engagement with renters; affordable rental property owners; communities of Black, Indigenous, and People of Color; and under-resourced individuals—providing resources for engagement and participation, and providing financial support for impacted individuals to participate in dockets and decision-making processes.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25F	F. Form an environmental justice accountability board which shall develop environmental justice-focused initiatives to be incorporated throughout the utility.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary
Docket No. E002/RP-19-368 In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy **April 15, 2022 Order**	Order Point 25	By January 1, 2023, and annually thereafter, Xcel shall file details describing stakeholder outreach and progress in its next resource planning docket, and in a separate docket to be established by the Executive Secretary.	E002/M-22-266 Appendix R: Equity Appendix S: Stakeholder Engagement Summary

Rules, Statutes, and Orders			
Statute, Rule or Order	**Subdivision or Order Point**	**Information Required by Statute, Rule or Order**	**2024-2040 IRP Location of Required Content**
Docket No. E002/M-21-694 In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project **July 26, 2022 Order**	Order Point 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. [For example, examine transportation, building and industrial electrification forecasts and the effects on load profiles in the near-term 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. 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 and 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 a 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 S: Stakeholder Engagement Summary November 1, 2023 Integrated Distribution Plan E002/M-23-452
E999/CI-14-643 In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3 **1/3/2018 Order**	Order Point 1	1. The Commission hereby quantifies and establishes the range of environmental cost of carbon dioxide emissions associated with electricity generation as follows: •The low end of the range shall reflect the global damage of the last (marginal) short ton emitted, calculated through the year 2100, with a 5.0% discount rate. •The high end of the range shall reflect the global damage of the last (marginal) short ton emitted, calculated through the year 2300, with a 3.0% discount rate.	Chapter 5: Economic Modeling Framework Appendix F: EnCompass Modeling Assumptions & Inputs
E999/CI-14-643 In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3 **1/3/2018 Order**	Order Point 3	3. In resource-selection proceedings, utilities shall continue to analyze potential resources under a range of assumptions about environmental values—including at least one scenario that excludes consideration of environmental externalities.	Appendix G: Scenario Sensitivity Analysis--PVRR & PVSC
Docket No. E999/CI-22-624 In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act **September 12, 2023 Order**	Order Point 1	The utilities shall maximize the benefits of the Inflation Reduction Act in future resource acquisitions and requests for proposals in the planning phase, petitions for cost recovery through riders and rate cases, resource plans, gas resource plans, integrated distribution plans, and Natural Gas Innovation Act innovation plans. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures. Reporting shall continue until 2032.	Appendix U: Inflation Reduction Act
Docket No. E002/M-19-33 In the Matter of Northern States Power Company's, d/b/a Xcel Energy, Petition to Expand its Renewable*Connect Program **August 12, 2019 Order**	Order Point 3	In current and future resource plans, Xcel must identify the resources dedicated to the Renewable*Connect program and must provide a thorough discussion of the present and forecasted resources that are necessary to meet its present and future demand for the program.	Chapter 2: Planning Landscape Chapter 3: Minimum System Needs

APPENDIX B – ACRONYMS AND TERMS

ACRONYM / TERM	DEFINITION
AABE	American Association of Blacks in Energy
AAPI	Asian American and Pacific Islander
ABLE	Accessibility, Be an Ally, Lead, and Empower
AC	Alternating Current
ACE	Affordable Clean Energy rule
ACEEE	American Council for Energy Efficient Economy
ACI	Activated Carbon Injection
ADMS	Advanced Distribution Management System
ADP	Advanced Determination of Prudence
AEO	Annual Energy Outlook
AFC	Accelerated Fleet Change
AIOIC	American Indian Opportunities Industrialization Center
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Aging Management Program
ANL	Argonne National Laboratory
APC	Adjusted Production Costs
ARDP	Advanced Reactor Demonstration Program
ARR	Avoided Revenue Requirements
A.S. King	Allen S. King Generating Plant
ASHP	Air-Source Heat Pumps
ATB	Annual Technology Baseline
AUAR	Alternative Urban Areawide Review
AWEA	American Wind Energy Association
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BLAX	Black Employees at Xcel Energy
BE	Beneficial Electrification
BESS	Battery Energy Storage System
BGEPA	Bald and Golden Eagle Protection Act
BIL	Bipartisan Infrastructure Law
BIPOC	Black, Indigenous, and People of Color
BO	Buildout Scenario
BPM	Business Practice Manual
BRD	Business Research Division
BRG	Business Resource Groups
BSER	Best System of Emission Reduction
BWCA	Boundary Waters Canoe Area
C&I	Commercial and Industrial (Customers)
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate

ACRONYM / TERM	DEFINITION
CAIDI	Net capacity factor of power plant, typically expressed as percentage, is ratio of its actual output over period of time to its potential output if it were possible for it to operate at full nameplate capacity indefinitely.
CAIR	Clean Air Interstate Rule
CAP	Competitive Acquisition Process
Capacity Factor	Measure of how often an electric generator runs for a specific period of time. Indicates how much electricity a generator actually produces relative to the maximum it could produce at continuous full power operation during the same period.
CapX2020	Coordinated transmission development effort by group of 11 regional utilities (the CapX2020 Utilities) in MN, ND, SD and WI.
CARB	California Air Resources Board
CBA	Cost-Benefit Analysis
C-BED	Community-Based Energy Development
CBECS	Commercial Buildings Energy Consumption Survey
CBP	Community Benefits Plan
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost of Service Study
CCRs	Coal Combustion Residuals (often referred to as coal ash)
CCS	Carbon Capture and Sequestration
CDL	Commercial Driver's License
CEE	Center for Energy and Environment
CEI	Center for Economic Inclusion
CEL	Capacity Export Limit
CEMS	Continuous Emissions Monitoring Systems
CEO	Clean Energy Organizations
CER	Capital Project Module
CERA	Cambridge Energy Research Associates
CERCLA	Comprehensive Environmental Response Compensation and Liability Act
CEWD	Center for Energy Workforce Development
CF	Coincidence Factor
CF2050	Carbon-Free 2050
CFC	Continued Fleet Change
CFPP	NuScale Power's Carbon Free Power Project
CFS	Carbon-Free Standard
CFTI	Carbo-Free Technology Institute
CH_4	Methane
CHP	Combined Heat and Power
CI or C&I	Commercial/Industrial

ACRONYM / TERM	DEFINITION
CIL	Capacity Import Limit
CIP	Conservation Improvement Program
Circuit Breaker	An electromechanical device used to configure the flow of electricity on the distribution grid. A circuit breaker is designed to open or close while electricity is flowing through the circuit. When a circuit breaker is open, no electricity is flowing through the circuit.
CISF	Consolidated Interim Storage Facility
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalents
CON	Certificate of Need
CONE	Cost of New Entry
CPD	Coincident Peak Demand
CP Node	Commercial Pricing Node
CRP	Certified Renewable Percentage
CSAPR	Cross-State Air Pollution Rule
CSG	Community Solar Garden
CT	Combustion Turbine
CWA	Clean Water Act
CWIP	Construction Work in Progress
DA	Day Ahead
DAV	Disabled American Veterans
DEED	Department of Employment and Economic Development
DEI	Diversity, Equity , ad Inclusion
DEM	Drive Electric Minnesota
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management Systems
DG	Distributed Generation
DIC	Disproportionately Impacted Communities
DIGT	Digester
DIR	Dispatch Intermittent Resource Protocol
DLOL	Direct Loss of Load
DNR	Department of Natural Resources
DOC	Department of Commerce
DOE	U.S. Department of Energy
DOI	Department of the Interior
DPP	Definitive Planning Process
DR	Demand Response
DSD	Minnesota Deemed Savings Database
DSM	Demand Side Management
DSP	Distributed Solar Parties
DSES	Distributed Solar Energy Standard
EAW	Environmental Assessment Worksheet

ACRONYM / TERM	DEFINITION
E3	Energy and Environmental Economics, Inc.
ECC	Economic Carrying Charge
ECN	Employee Connection Network
ECO	Energy Conservation and Optimization
EE	Energy Efficiency
EERC	Energy & Environmental Research Center
EERE	Office of Energy Efficiency and Renewable Energy
eGRID	Emissions and Generation Resource Integrated Database
EGU	Electric Generating Unit
EJ	Environmental Justice
EJAB	Environmental Justice Advisory Board
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELGs	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPA Clean Air Act 111d Rule	Draft regulation to reduce carbon dioxide gas emissions from existing power plants that burn coal and other fossil fuels.
EPA SC-GHG	Environmental Protection Agency Social Cost of Greenhouse Gases
EPE	Energy Production Estimate
EPRI	Electric Power Research Institute
EQB	Environmental Quality Board
ERIS	Energy Resource Interconnection Service
ESA	Endangered Species Act
ESAG	Equity Stakeholder Advisory Group
ETAC	Energy Transition Advisory Committee
EVs	Electric Vehicles
Externality Values	Range of environmental costs.
FAN	Field Area Networks
Fault	Abnormal condition on electric system, such as short circuit, broken wire or intermittent connection.
Feeder	Lines connecting distribution substations to taps.
FERC	Federal Energy Regulatory Commission
FERC Order 1000	Rule mandating how public utility transmission providers plan for and allocate costs of new projects on regional and interregional basis.
FGD	Flue-Gas Desulfurization
FIPs	Federal Implementation Plans
FTE	Full-Time Equivalent
FL&U	Fuel Lost and Unaccounted
FLISR	Fault Location, Isolation, and Service Restoration

ACRONYM / TERM	DEFINITION
FOM	Fixed Operation & Maintenance Costs
FTR	Financial Transmission Right
FWS	U.S. Fish and Wildlife Service
Gas Burn	Energy from New Natural Gas Generation
GAF	Generation Module
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GRIP	Grid Resilience and Innovation Partnership
GROW	Growth and Retention of Women
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
HDVs	Heavy-Duty Vehicles
HI	Hazardous Index
HFPO-DA	Hexafluoropropylene Oxide Dimer Acid
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IB MACT	Hazardous Air Pollutants from Industrial Boilers
IBEW	International Brotherhood of Electrical Workers
ICAP	Installed Capacity Value
ICE	Internal Combustion Engine
IDP	Integrated Distribution Plan
IDS	Interdepartmental Sales
IGCC	Integrated Gasification Combined Cycle
IIJA	Infrastructure Investment Jobs Act
ILR	Inverter Loading Ratios
ILSR	Institute for Local Self-Reliance
ILTF	Indian Land Tenure Foundation
INPO	Institute of Nuclear Power Operations
IPaC	Information for Planning and Consultation
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installations
ISO	Independent System Operators
ISP	Integrated System Planning
ISP	Interim Storage Partners
ITC	Investment Tax Credit
ISOs	Independent System Operators
JCOSS	Jurisdictional Cost of Service Study

ACRONYM / TERM	DEFINITION
JTIQ	Joint Targeted Interconnection Queue
kV	Kilovolt
kVA	Kilovolt Amps: 1,000 Volt-Amps. Volt is measure of force of electricity. Amp (Ampere) is measure of flow of electricity.
kWh	Kilowatt
LAF	Load Module
LBA	Load Balancing Authorities
LCA	Life Cycle Assessments
LCM	Life Cycle Management
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
LCR	Local Clearing Requirement
LCRI	Low-Carbon Resources Initiative
LDES	Long Duration Energy Storage
LDVx	Light-Duty Vehicles
LEAP	Long-range Energy Alternatives Planning
LED	Solid State Lighting
LFC	Limited Fleet Change
LMF	Load Management Forecast
LMPs	Locational Marginal Prices
LND	Landfill
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LR	License Renewal
LRR	Local Reliability Requirement
LRTP	Long Range Transmission Plan
LRZ	Local Resource Zone or Zone
LSE	Load Serving Entities
LTRA	Long Term Reliability Assessment
MATS	National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Power Plants. This rule is often referred to as the Mercury and Air Toxics Standard.
MBTA	Migratory Bird Treaty Act
MCLG	Maximum Containment Level Goal
MCPS	Market Congestion Planning Study
MDVs	Medium-Duty Vehicles
MEC	Mankato Energy Center
MEFF	Minnesota Energy Future Framework
MGP	Manufactured Gas Plants

ACRONYM / TERM	DEFINITION
MISO	Midcontinent Independent System Operator, Inc.: Non-profit organization providing reliable coordination and regional planning services including: regional planning, generation interconnection, maintenance coordination, market monitoring and dispute resolution.
MLBO	Mille Lacs Band of Ojibwe
MMBTU	Million British Thermal Units
MMERA	Minnesota Mercury Emissions Reduction Act
MNDNR	Minnesota Department of Natural Resources
MNEC	Minnesota Energy Connection
MNGP	Monticello Nuclear Generating Plant
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
M-RETS	Midwest Renewable Energy Tracking System
MSW	Municipal Solid Waste
MTEP	MISO Transmission Expansion Plan
MTO	Minnesota Transmission Owners
MW	Megawatt
MWh	Megawatt Hour
MVA	Mega Volt Amps: 1,000,000 amps or 1,000 kVA
MVP	Multi Value Project: Regional transmission solutions that meet one or more of three goals: reliably and economically enable regional public policy needs, provide multiple types of regional economic value, and provide a combination of regional reliability and economic value.
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NaVOBA	National Veteran-Owned Business Association
NAYGN	North American Young Generation in Nuclear
NCP	Non-MISO Coincident Peak
NDPSC	North Dakota Public Service Commission
NEEP	Northeast Energy Efficiency Partnerships
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGEA	Minnesota's Next Generation Energy Act
NGIA	Natural Gas Innovation Act
NGLCC	National Gay & Lesbian Chamber of Commerce
NHRG	Nuclear Human Resource Group

ACRONYM / TERM	DEFINITION
NMFS	National Marine Fisheries Service
NMSDC	National Minority Supplier Development Council
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRIS	Network Resource Interconnection System
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NSPS	New Source Performance Standards
NSR	New Source Review Section of the Clean Air Act
NSRDB	National Solar Radiation DataBase
NWA	Non-Wires Alternatives
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
O_3	Ozone
OCED	Office of Clean Energy Demonstrations
OFA	Over-Fire Air
OSPA	Sales to Public Authorities
Pb	Lead
PCBs	Polychlorinated Biphenyls
PCOR	U.S. Department of Energy's Plains Carbon Dioxide Reduction Partnership
PFAS	Polyfluoroalkyl Substances
PFBA	Perfluorobutanoic Acid
PFBS	Perfluorobutanesulfonic Acid
PFDA	Perfluorodecanoic Acid
PFHxA	Perfluorohexanoic Acid
PFHxS	Perfluorohexanesulfonic Acid
PFNA	Perfluorononanoic Acid
PFOA	Perfluorooctanoic Acid
PFOS	Perfluorooctanesulfonic Acid
PI	Prairie Island
PiE	Partners in Energy
PINGP	Prairie Island Generating Plant
PIIC	Prairie Island Indian Community
PINGP	Prairie Island Nuclear Generation Plant
PIRA	Petroleum Industry Research Associates

ACRONYM / TERM	DEFINITION
Plume Blight	Smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or small group of sources.
PM	Particulate Matter
$PM_{2.5}$	Fine Particulate Matter under 2.5 micrometers
PM_{10}	Coarse Particulate Matter under 10 micrometers
POI	Point of Interconnection
POTW	Publicly-Owned Treatment Works
PP	Park Potential
PPA	Power Purchase Agreement
PPB	Parts Per Billion
PPM	Parts Per Million
PPT	Parts Per Trillion
PRA	Planning Resource Auction
Prairie Island	Prairie Island Nuclear Generating Plant
PRC	Planning Resource Credits
PRPs	Potentially Responsible Parties
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
Proview	Expansion Planning Module
PSD	Prevention of Significant Deterioration Section of the Clean Air Act
PSHL	Public Street and Highway Lighting
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
PVSC	Present Value of Societal Costs
PY	Planning Year
RA	Resource Adequacy
RAC	Reliability Assessment Commitment
RAVI	Reasonably Attributable Visibility Impairment
RBDC	Reliability-Based Demand Curve
RCC	Regulatory Cost of Carbon
RCR	Reconnect Rondo
RCRA	Resource Conservation and Recovery Act
RDF	Refuse Derived Fuel or Renewable Development Fund
RDF	Renewable Development Fund
Recloser	Circuit breaker that includes mechanism to automatically close (reconnect) after set period of time. Reclosers are used to restore service after momentary fault.
RECAP	E3's Renewable Energy Capacity model

ACRONYM / TERM	DEFINITION
RECs	Renewable Energy Credits: A certificate representing all of the environmental attributes of one MWh of generation from a renewable resource.
Reference Case	Baseline scenario identifying necessary resource additions.
REMI	Regional Economic Models, Inc.
REO	Renewable Energy Objective
REPI	Renewable Energy Production Incentive
RES	Renewable Energy Standard
RESOLVE	E3's Renewable Energy Solutions model
Retrofill	Remove contaminated oil and replace with clean oil.
RFP	Request For Proposal
RGGI	United States' Regional Greenhouse Gas Initiative
RGU	Responsible Government Units
RHR	Regional Haze Rule
RICE	Reciprocating Internal Combustion Engines
RIIA	Renewable Integration Impact Assessment
RIM	Rate Impact Measure
RLB	Rondo Land Bridge
RMP	Resilient Minneapolis Project
ROE	Return on Equity
RPS	Renewable Portfolio Standard
RRA	Regional Resource Assessment
RSG	Revenue Sufficiency Guarantee (Charges): Direct result of production shortfalls relative to earlier forecasts.
RTE	Round-Trip Efficiency
RTF	Resource Treatment Framework
RTO	Regional Transmission Organization
RTR	Risk and Technology Review
S*R	Solar Rewards (Company's Program)
S*RC	Solar Rewards Community (Company's Community Solar Gardens Program)
SAC	Seasonal Accredited Capacity
SAIDI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SAIFI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition

ACRONYM / TERM	DEFINITION
SCC	Social Cost of Carbon
SC-GHG	Social Cost of Greenhouse Gases
SCORE	Select Committee on Recycling and Environment
SCR	Selective Catalytic Reduction
SDPUC	South Dakota Public Utilities Commission
SEA	Strategic Energy Assessment
SEPA	Solar Electric Power Association
SES	Minnesota Solar Energy Standard: Minn. Stat. § 216B.1691, subd. 2f, which requires 1.5% of retail sales to be sourced from new solar resources. SES is incremental to the Renewable Energy Standard (RES).
SFH	Single Family Housing
SHAW	Shoulder Average Winds
SIP	State Implementation Plan
SLR	Subsequent License Renewal
SMR	Small Module Nuclear Reactor
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxide
SolarTAC	Solar Technology Acceleration Center
SPP	Southwest Power Pool
SQ	Status Quo
S-RECs or SREC	Solar Renewable Energy Credits: Created from a solar resource installed after August 1, 2013 and eligible to be used for compliance with the MN Solar Energy Standard.
SRO	Senior Reactor Operator
SRREN	Special Report on Renewable Energy Sources and Climate Change Mitigation
STEM	Science, Technology, Engineering, and Mathematics
Switch	Electromechanical devise used to configure the flow of electricity on distribution grid. A switch is designed to be opened or closed when electricity is not flowing through circuit. When switch is open, no electricity is flowing through circuit.
Tap	Final leg of distribution system before connecting to customer premises.
TCCRI	Twin Cities Climate Resiliency Initiative
TDEC	Tennessee Department of Environment and Conservation
TEP	Transportation Electrification Plan
TES	Thermal Energy Storage
THI	Temperature Humidity Index
TIR&C	Treasure Island Resort & Casino
TO	Transmission Owners

ACRONYM / TERM	DEFINITION
TOU	Time-of-Use
TPS	Technical Planning Study
Transcos	Transmission-only entities designed to respond to the FERC Order 1000.
Transformer	Electromechanical devise that converts alternating current to higher or lower voltage.
Transmission Inadequacies	Identified deficiencies in the transmission system that need to be upgraded to keep the transmission system within its defined limits.
TRC	Total Resource Cost
TSD	Technical Support Document
UAMPS	Utah Associated Municipal Power Systems
UCAP	Production Capability Value
UDEQ	Utah Department of Environmental Quality
USACE	U.S. Army Corps of Engineers
USGS	United States Geological Survey
V2G	Vehicle-To-Grid
VAR	Voltage and Reactive Power
VETS	Veterans and Employees Together in Service
VMT	Vehicle Miles Traveled
VNP	Voyageurs National Park
VOCs	Volatile Organic Compounds
VPP	Virtual Power Plants
W2B	Wind2Battery Project
WACC	Weighted Average Cost of Capital
WBENC	Women Business Enterprise National Council
WCS	Waste Control Specialists
WDNR	Wisconsin Department of Natural Resources
WEG	Wind Energy Guidelines
WIN	Women's Interest Network
WOTUS	Waters of the United States
WRC	Wild Rivers Conservancy
WTP	Worker Transition Plan
XE WiN	Women in Nuclear
YPN	Young Professionals Network
ZRC	Zonal Resource Credit

APPENDIX C – ABOUT XCEL ENERGY

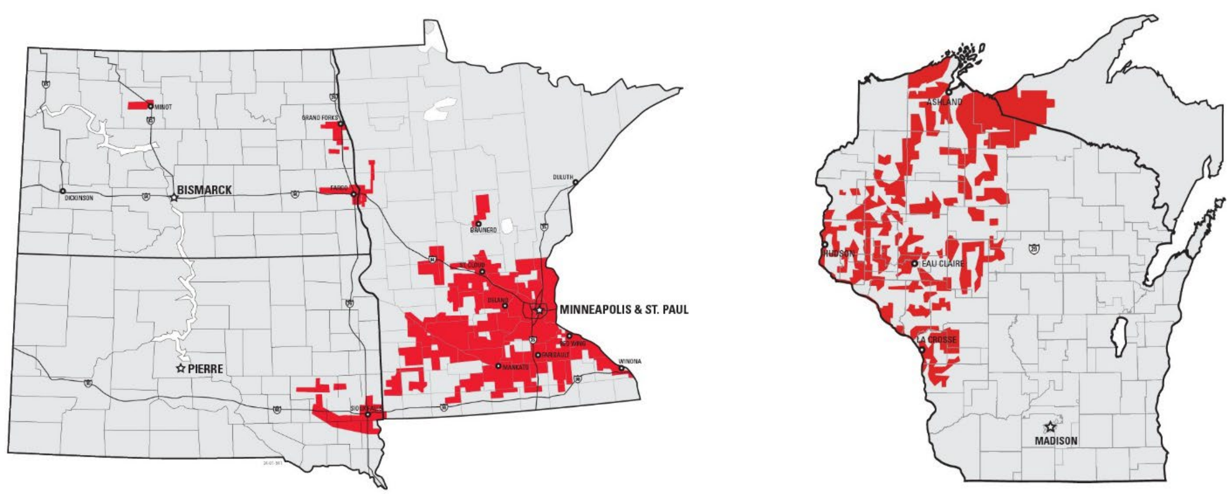
Based in Minneapolis, Xcel Energy serves 3.8 million electricity and 2.1 million natural gas customers through four regulated operating companies that generate electrical power, and transmits, distributes, and sells it to residential and business customers within service territories assigned by state regulators:

- Public Service Company of Colorado
- Northern States Power Company-Minnesota
- Northern States Power Company-Wisconsin
- Southwestern Public Service Company

Northern States Power Company-Minnesota (NSPM), and Northern States Power Company-Wisconsin (NSPW), collectively the NSP Companies, are public utilities organized under the laws of the state of Minnesota, and Wisconsin. The NSP Companies own and operate the five-state integrated NSP System pursuant to the terms of the Federal Energy Regulatory Commission (FERC) approved Interchange Agreement. The NSP Companies have about 1.8 million electricity customers in the upper Midwest.

Figure C-1 shows the Company's upper Midwest service territories in the states of Minnesota, Wisconsin, Michigan, North Dakota, and South Dakota.

Figure C-1: NSP Companies' Upper Midwest Service Territory

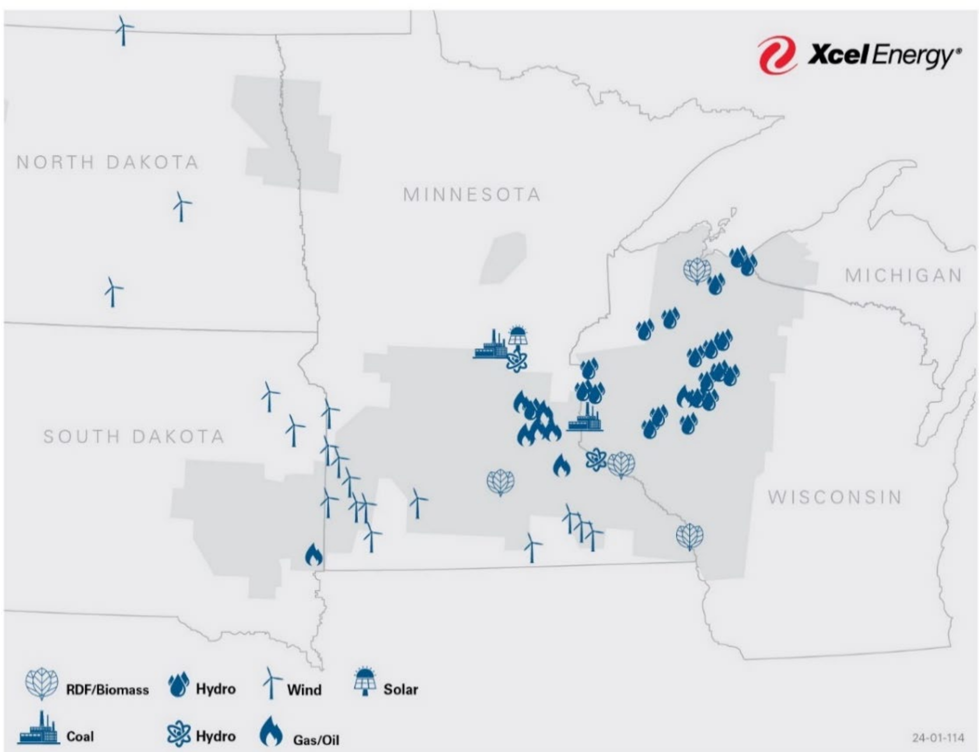


Approximately 89 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 11 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers make up approximately 23 percent of electricity sales, with commercial, industrial, and other customers making up most of the remaining 77 percent.

NSP currently provides jobs to about 6,500 people[1] in the Upper Midwest. In 2023, we initiated 18 economic development projects for our local communities, which are projected to create more than $2.4 billion in capital investments and 1,400 new jobs in those communities. Our Vision is to be the preferred and trusted provider of the energy our customers need and with a mission to provide our customers with the safe, clean, reliable energy services they want and value at a competitive price.

The Company owns and operates multiple electric generation facilities serving this area using a variety of technologies and fuels including, coal, natural gas, wind, solar, hydro, refuse derived fuel, and nuclear. The map in Figure C-2 illustrates this fleet of generation resources.

Figure C-2: NSP System Generation Resources



[1] Includes employees and contract workers.

The NSP System includes power plants with a net maximum capacity of approximately 9,500 MW, 45,000 conductor miles of transmission lines, and approximately 558 transmission and distribution substations. We also have over 3,700 MW of Purchase Power Agreements (PPAs).

APPENDIX D – ENERGY ADEQUACY ANALYSIS

I. INTRODUCTION

The electric grid is undergoing a significant transformation, moving away from traditional thermal baseload sources to more variable energy sources like wind, solar, and battery energy storage. This shift brings new challenges and complexities in maintaining grid resilience and reliability.

We are increasingly focused on ensuring that our system remains reliable, so that we can continue to deliver the power our customers demand, while responsibly meeting the State's carbon reduction goals. Our focus on reliability is particularly important because, as we are planning to retire our entire coal fleet (over 2,000 MW of baseload generation), we have nearly 1,700 MW of power purchase agreements (PPAs) set to expire between 2025 and 2028. At the same time, our neighbors are also retiring firm capacity, which makes relying on the market more difficult. Given these challenges, traditional reserve margins and capacity-based estimates are no longer sufficient to ensure our system is prepared for the challenges of extreme weather and changing grid dynamics. To ensure reliability, enhanced planning and energy adequacy assessments are necessary.

In addition to planning to meet our planning obligations without reliance on MISO, we have taken steps to further refine our energy adequacy analysis. We conducted energy adequacy back casting analysis to ensure our system has the reliable energy it needs to serve all customers at every hour of every day. We also examined the inertial floor of our system to assess how the grid would perform in the absence of traditional baseload generation. Our studies go beyond traditional EnCompass modeling to verify the need for firm dispatchable resources and inertia to ensure reliable service for our customers.

II. UTILITY PLANNING FOR SYSTEM NEEDS

Minnesota law requires that we demonstrate that we have sufficient capacity to meet our obligations for a five-year period consistent with Minn. Stat. § 216B.2422. Historically, we planned to have enough resources to meet our load serving needs. Though MISO plays a critical role in ensuring the reliable and efficient operation of the electric grid in the Midwest region of the United States by managing the grid and determining the availability and need for capacity, energy, and ancillary services, we cannot simply rely on MISO to address our capacity needs and ensure the reliability of our system.

MISO's Resource Adequacy (RA) construct will not necessarily ensure there is sufficient firm capacity online to cover the needs of load serving entities. The MISO region relies on Load Serving Entities (LSEs) and market participants to supply the generation resources needed to serve load. MISO also oversees a market to ensure the resources that are available are used efficiently to serve load across the MISO footprint. While MISO can manage the distribution of resources, it cannot ensure that there is enough power generation to meet demand and does not guarantee that there will be enough firm capacity to meet the needs of LSEs.

MISO's role in generation planning is limited. Generation planning is reserved for the states (except in IL). MISO has the ability to set a reserve margin but not the ability to determine what resources will be procured to meet it. While we utilize MISO market energy purchases when they are more cost-effective than our own resources, these purchases are non-firm and do not contribute to our capacity for meeting our seasonal Planning Reserve Margin Requirements (PRMR) obligations as a MISO market participant. Compliance with PRMR obligations is for single-year periods, and the acquisition of new generation capacity often spans multiple years. Our most cost-effective and responsible strategy is to plan for the acquisition of generation capacity several years in advance.

Relying on the MISO Planning Resource Auction (PRA) for securing capacity for single-year periods is not a viable resource planning option. Therefore, it is crucial that we continue to plan for a system with sufficient capacity to meet our customer's energy needs.

A. Navigating the Challenges of Changing Energy Landscapes and Extreme Weather Conditions

The challenges and considerations for maintaining reliability in the face of changing energy landscapes and extreme weather conditions underscores the importance of long-term planning and the integration of new technologies and resources into the grid. Utilities are facing mounting pressure to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.[1] Extreme weather events continue to pose the greatest risk to its reliability and stability. The North American Reliability Corporation (NERC) concluded that much of North America is again at an elevated risk of having insufficient energy supplies to meet

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[1] 2023 Long-Term Reliability Assessment (LTRA): North American Electric Reliability Corporation, 2023 Long-Term Reliability Assessment (2023). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_Infographic_2023.pdf.

demand in extreme operating conditions.[2] As the resource mix on the grid continues to evolve, the risk associated with continuity of energy supply must be managed.

For many years, the regional energy supply has relied on large generators located near large load centers. However, in recent years, there has been a marked shift toward renewable and distributed resources that may be distant from major load centers or may provide variable production profiles. This transition toward more variable resources located far away from load has only increased in recent years.

Consistent with our 2019 Plan, we recently retired Sherco Unit 2, and will retire Sherco Unit 1 in 2026, King in 2028, and Sherco 3 in 2030. Ultimately, the retirements of all the Sherco and King units will remove a total of 2,400 MWs of from our system by 2030. Others are also removing base load from their system. For example, according to the most recent MISO Regional Resource Assessment (RRA)[3] in LRZ1, coal generation is expected to decline by more than 3,200 MWs from 2027 to 2037. This generation is being replaced by less than 1.5 GWs of dispatchable generation. While a substantial amount of non-dispatchable resources is also replacing this retiring generation, MISO is still forecasting a 1 GWs reduction in accredited capacity from 2027-2032 for LRZ1. These forecasted replacements create a systemic risk that the market for capacity and energy in MISO LRZ1 will not be enough to serve the load in LRZ1—including that of Xcel Energy—under certain weather conditions. This situation could lead to an energy shortfall, disrupting the supply to consumers and potentially causing widespread outages. Moreover, similar risk extends to areas immediately adjacent to LRZ1 – LRZ2 and LRZ3 – as shown in Figure D-1 below.

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[2] 2023–2024 Winter Reliability Assessment: North American Electric Reliability Corporation, 2023-2024 Winter Energy Market and Electric Reliability Assessment (2023), https://www.nerc.com/news/Pages/Generator-Fuel-Supplies,-Power-Plant-Winterization,-Load-Forecasting-Complexity-Increase-Reliability-Risk-in-North-America-.aspx

[3] 2023 Regional Resource Assessment, MISO. (November 2023). RAN Reliability Requirements and Sub-annual Construct (misoenergy.org)

Figure D-1: Local Resource Zones[4]

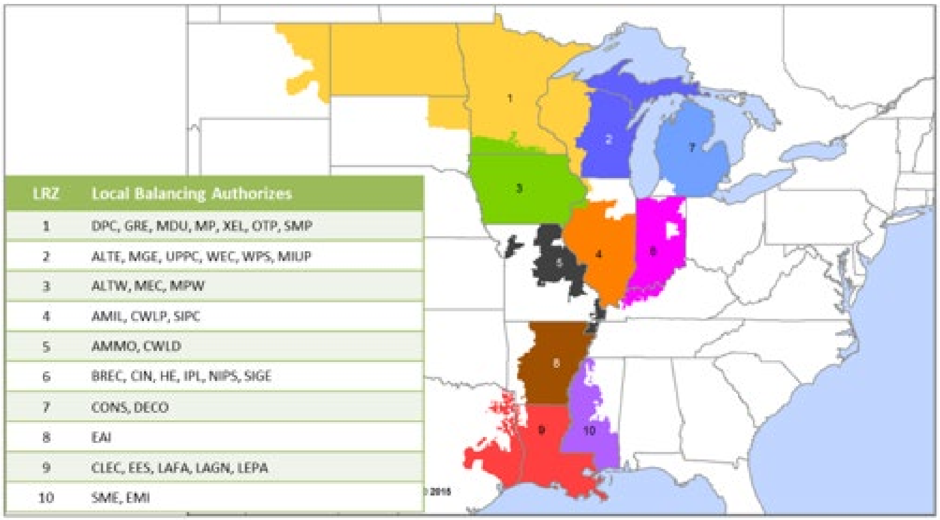


Table D-1 shows RRA projections of no excess capacity in LRZ3 and an even larger capacity shortfall than LRZ1 in the same period. These adjacent LRZs are critical for the Company's market interactions and reduction of available capacity in these locations further threatens the reliability of the energy supply for LRZ1, as it suggests they may not always be able to provide support to LRZ1 if needed. This scenario underscores the need for strategic planning and robust risk management measures to ensure the uninterrupted operation of the energy market.

Table D-1: Estimated Net Change in Resource Type for Surrounding Load Balancing Authorities

	2027 GW Surplus or (Gap) in Accredited Capacity	2032 GW Surplus or (Gap)
LRZ 1 (Company's LRZ)	**1.0**	**(1.0)**
LRZ 2	**(1.0)**	**(3.0)**
LRZ 3	**1.0**	**0.0**

In the face of these challenges, it is imperative that we explore and implement solutions that can effectively mitigate these risks. The amount of dispatchable capacity that is scheduled to retire from our system in the next several years requires that we earnestly analyze the reliability of our system to ensure that we can continue to be resilient and that our customers continue to experience the high levels of reliability they expect. It is

[4] Source, MTEP18 Book 2 Resource Adequacy264875.pdf (misoenergy.org)

important that we plan to meet our energy and capacity obligations without overreliance on the market or exposing our customers to excessive risk.

III. ENERGY ADEQUACY ANALYSIS

To ensure we would have sufficient capacity on our system to meet our customers' needs across hours of the year, we stress tested our Preferred Plan against historical hourly load and renewable production data using Encompass modeling software. The Encompass modeling reflects actual system and market conditions and hourly production cost analysis. We use the model's full chronological modeling capabilities to run dispatch and cost analyses for the years 2027 to 2030, 2033, 2034 and 2040.

Using each historical year from 2016 to 2022, we developed an 8,760-hour historical demand shape, along with monthly peak and energy forecasts, to calculate the future system level demand and shape to use in the Encompass model. All existing wind and solar resources were dispatched based on their actual historical 8,760-hour production profiles or an 8,760-hour profile from a nearby facility. Generic facilities were given a random 8,760-hour profile. Using this historical data, we conducted a special study on four plans to ensure we would have sufficient capacity on our system to meet our customers' needs under varying weather conditions:

(1) Reference Case (Scenario 1),
(2) Preferred Plan (Scenario 3),
(3) Low Load (Scenario 3), and
(4) Market Access Optimization (Scenario 3 optimized with 2,300 MW of hourly market access).

This analysis allows us to assess the capacity and energy adequacy of our plans. We evaluated these plans on six different measures:

1. Native Capacity Shortfall: Hours of insufficient system capacity in each year.
2. Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
3. Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.
4. Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
5. MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

The results for each scenario in 2030 and 2040 are shown below in Table D-2:

Table D-2: Summary of 2030 Energy Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	Historical Year - Hourly Conditions in 2030	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliance Hours	MISO Market Reliance (MWh)
Reference Case (Scenario 1)	2016 Historical	2	76	1	94	2	153
	2017 Historical	0	0	0	0	0	0
	2018 Historical	0	0	0	0	0	0
	2019 Historical	0	0	0	0	0	0
	2020 Historical	0	0	0	0	0	0
	2021 Historical	0	0	0	0	1	192
	2022 Historical	0	0	0	0	0	0
Preferred Plan (Scenario 3)	2016 Historical	1	83	1	83	1	83
	2017 Historical	0	0	0	0	0	0
	2018 Historical	0	0	0	0	0	0
	2019 Historical	0	0	0	0	0	0
	2020 Historical	1	219	1	219	2	590
	2021 Historical	0	0	0	0	1	204
	2022 Historical	0	0	0	0	0	0
Low Load (Scenario 3)	2016 Historical	1	33	1	33	1	33
	2017 Historical	0	0	0	0	0	0
	2018 Historical	0	0	0	0	0	0
	2019 Historical	2	94	2	174	2	188
	2020 Historical	2	150	2	294	2	736
	2021 Historical	0	0	0	0	2	487
	2022 Historical	0	0	0	0	0	0

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2030**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
Market Access Optimization (Scenario 3 Market On Expansion Plan)	**2016 Historical**	**54**	**484**	**7**	**1,684**	**61**	**32,204**
	2017 Historical	**48**	**272**	**5**	**953**	**69**	**25,023**
	2018 Historical	**65**	**344**	**6**	**1,312**	**102**	**40,769**
	2019 Historical	**74**	**463**	**6**	**1,368**	**94**	**45,356**
	2020 Historical	**83**	**415**	**7**	**1,479**	**109**	**57,072**
	2021 Historical	**61**	**269**	**5**	**1,082**	**100**	**41,205**
	2022 Historical	**20**	**290**	**3**	**1,144**	**24**	**7,254**
	**** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)**						

As shown in the table above, the Preferred Plan performs well across energy adequacy metrics. There are only two hours of native capacity shortfall across the seven historic years tested, resulting in limited dependence on the market. There are only four hours across the seven historical test years where the Preferred Plan requires market purchases in order to meet load serving needs. The Reference Case and Low Load scenarios also result in limited market dependence.

In contrast, under the Market Access Optimization, which allows the capacity expansion to optimize assuming market access of 2300 MWs in all hours of the year, the results show that the plan exposes our customers to excessive risk. There are 405 hours across the seven historic years where the plan has insufficient capacity to meet needs. This results in 509 hours where the plan cannot meet load serving needs and must rely on market purchases of nearly 250,000 MWhs of energy.

Our analysis of 2040, below, shows similar results as displayed in Table D-3 below:

Table D-3: Summary of 2040 Energy Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2040**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
Reference Case (Scenario 1)	2016 Historical	5	202	2	335	17	7,037
	2017 Historical	0	0	0	0	0	0
	2018 Historical	2	182	1	317	9	3,543
	2019 Historical	0	0	0	0	2	44
	2020 Historical	0	0	0	0	18	8,348
	2021 Historical	1	554	1	554	19	15,476
	2022 Historical	2	20	1	40	2	40
Preferred Plan (Scenario 3)Scenario 3	2016 Historical	5	190	2	310	14	4,622
	2017 Historical	0	0	0	0	0	0
	2018 Historical	1	271	1	271	5	1,667
	2019 Historical	0	0	0	0	0	0
	2020 Historical	0	0	0	0	7	1,671
	2021 Historical	1	323	1	323	22	10,166
	2022 Historical	1	6	1	6	1	6
Low Load (Scenario 3)	2016 Historical	5	249	3	489	5	1,436
	2017 Historical	0	0	0	0	0	0
	2018 Historical	2	171	1	299	3	1,026
	2019 Historical	2	298	2	489	2	595
	2020 Historical	2	98	1	135	9	787
	2021 Historical	1	45	1	45	15	3,527
	2022 Historical	2	118	1	158	2	237
Market Access Optimization	2016 Historical	31	667	4	1,557	58	45,347
	2017 Historical	12	210	3	387	40	18,674

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2040**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
	2018 Historical	38	347	6	1,461	122	67,535
	2019 Historical	41	410	4	1,164	77	41,561
	2020 Historical	32	318	4	954	100	69,543
	2021 Historical	34	452	7	1,627	91	64,575
	2022 Historical	12	299	2	1,153	13	5,380
	** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)						

Similar to the results for 2030, the Preferred Plan performs well across energy adequacy metrics in 2040. There are only 8 hours of native capacity shortfall across the seven historic years tested, resulting in limited dependence on the market. There are 36 hours across the seven historical test years where the Preferred Plan requires market purchases in order to meet load serving needs. The Reference Case and Low Load scenarios also result in limited market dependence.

In contrast, under the Market Access Optimization, which allows the capacity expansion to optimize assuming market access of 2300 MWs in all hours of the year, the results exposes our customers to excessive risk. There are 200 hours across the seven historic years where the plan has insufficient capacity to meet needs. This results in 501 hours where the plan cannot meet load serving needs and must rely on market purchases of over 300,000 MWhs of energy.

Limiting market dependence is important for both cost and reliability. During hours when system resources cannot meet load serving needs, purchases from the market are the only option to meet needs. During these hours, we are exposed to the prevailing Locational Marginal Energy Prices (LMPs) at load. If LMPs are high, those high cost will increase customer bills. If LMPs are high over multiple hours, those impact could be significant. More importantly, if resources are not available in the market, customers may be subjected to reliability impacts. As one of the largest utilities in MISO Zone 1, the potential for reliability impacts in the region are greater if we have insufficient resources to meet our load serving needs.

Figures D-2 through D-5 below provide additional insight into the energy adequacy of the four plans analyzed.

Figure D-2: Reference Case (Scenario 1)

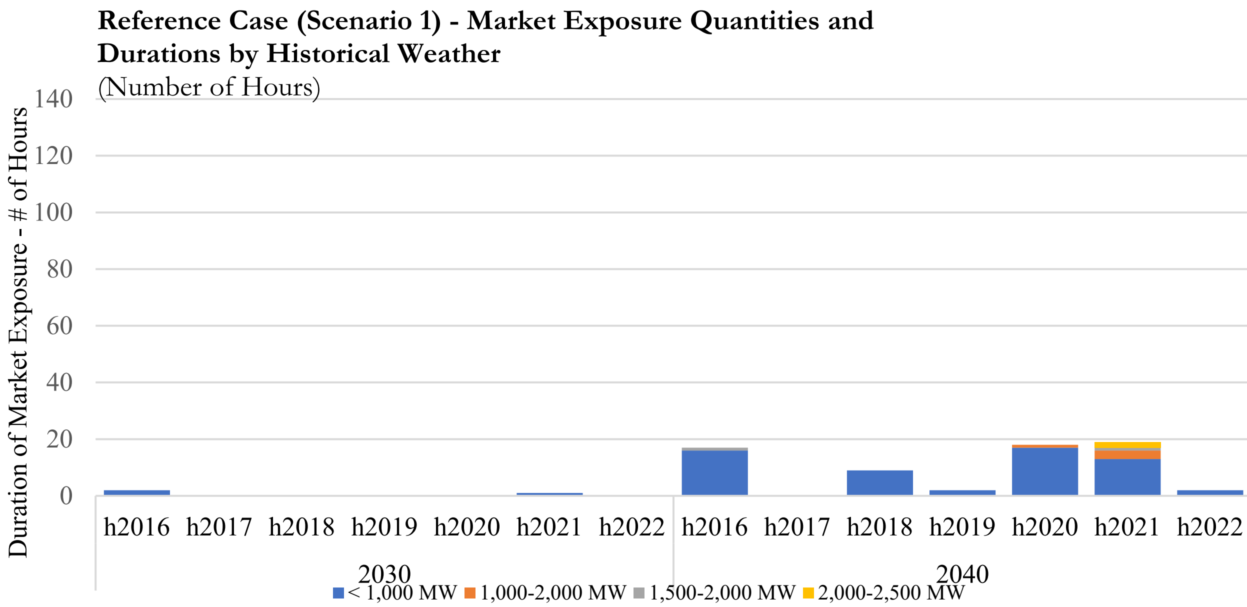


Figure D-3: Preferred Plan (Scenario 3)

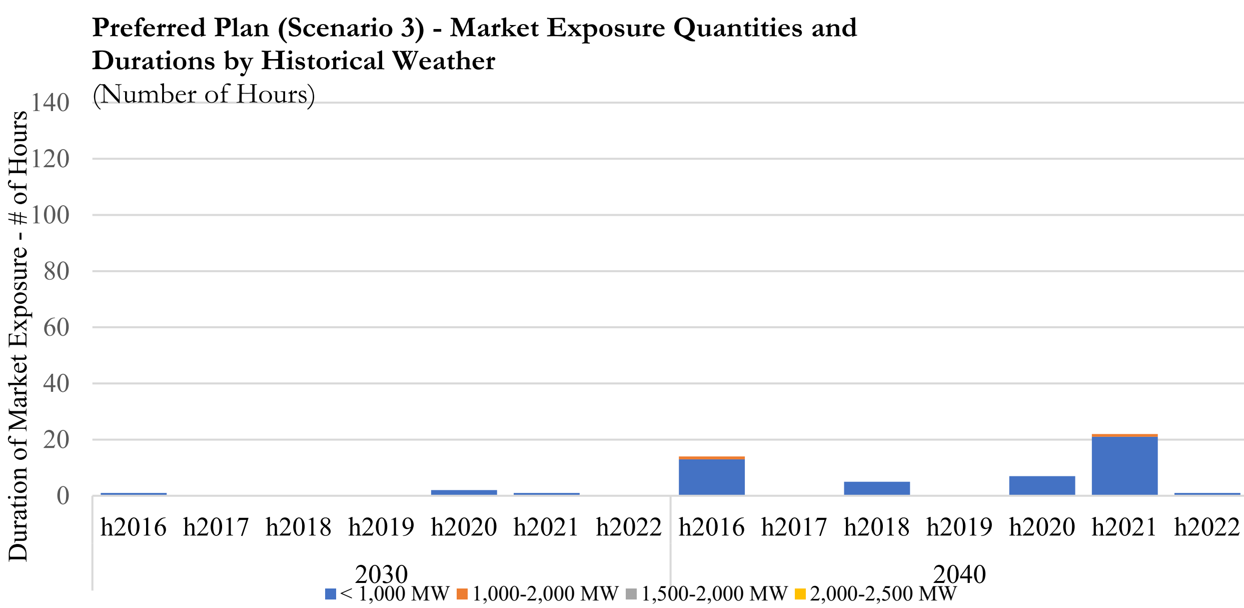


Figure D-4: Low Load (Scenario 3)

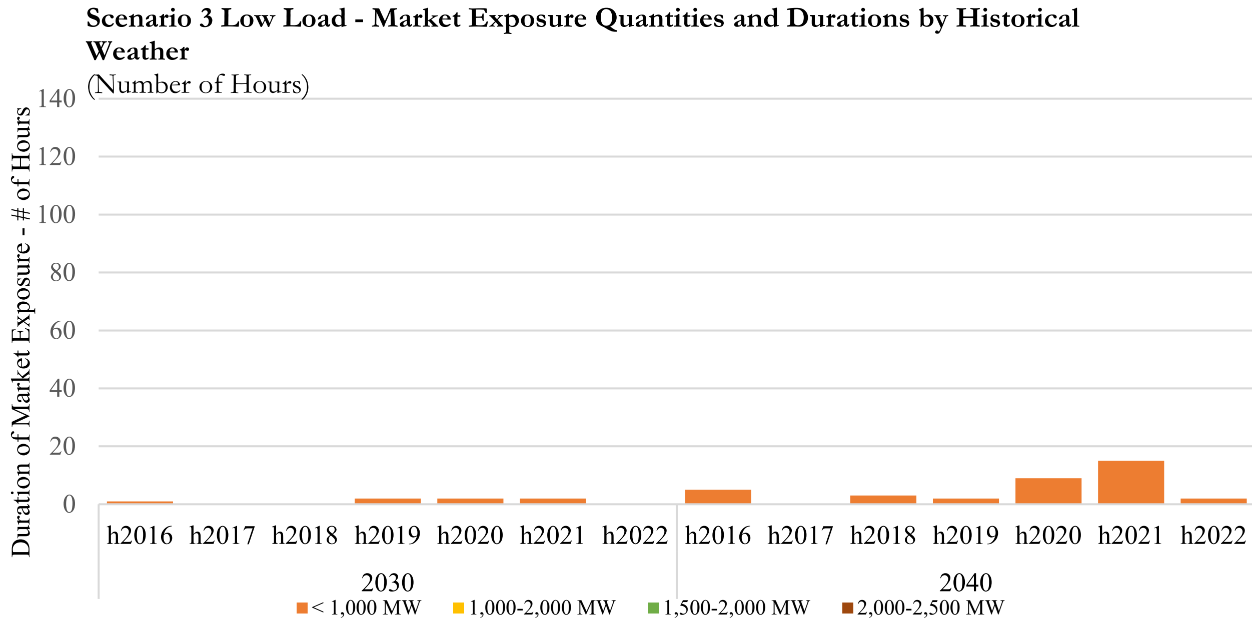
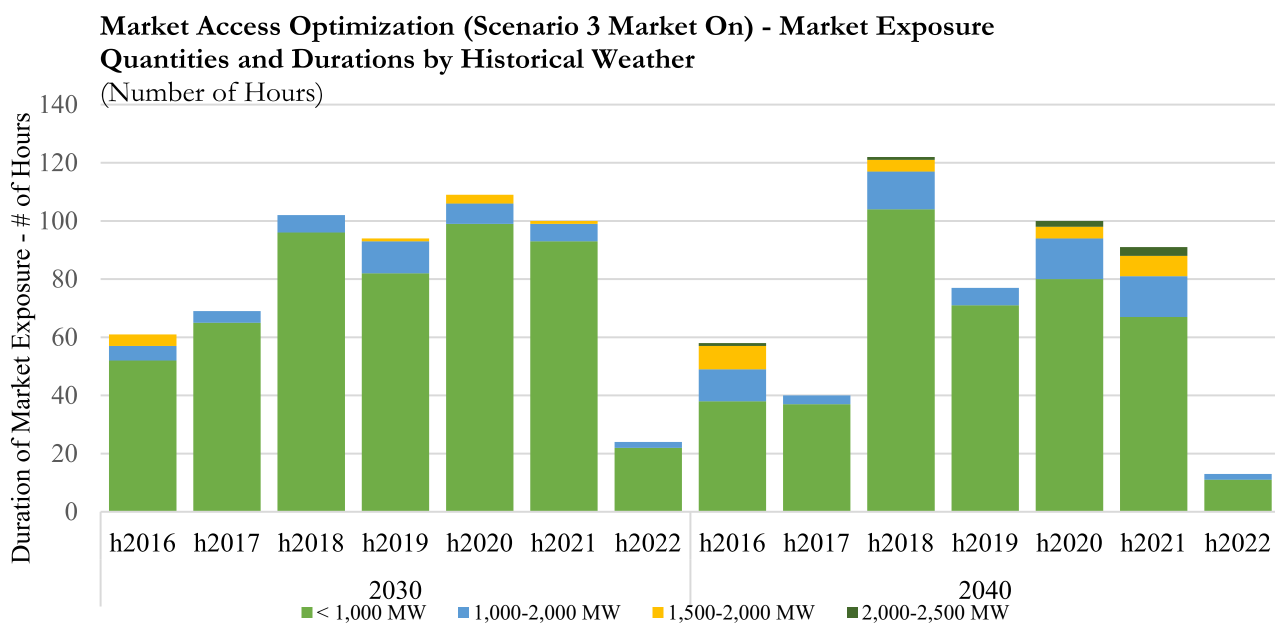


Figure D-5: Market Access Optimization (Scenario 3 optimized with 2,300 MW of hourly market access).



The figures above show the market dependence of each scenario analyzed. The bar for each historic year shows the impact in 2030 in 2040 both in terms of the number of hours of market dependence and the magnitude of those hours. The darkest green

shows hours where over the system must rely on the market for over 2,000 MWs of purchases in order to serve load. Consistent with the results above, the Preferred Plan, Reference Case and Low Load scenarios also result in limited market dependence.
In contrast, the Market Optimization analysis shows significant market dependence.

The tests and metrics above focus on limiting market dependence. There are many reasons market exposure can occur, including fluctuations in pricing, weather, load, or generation that last for a few acute hours or for 1–2-day periods. However, in addition to limiting market dependence across all events, different plans can also differ starkly in terms of how they weather a longer period – 4 days – of lower than expected solar and wind generation.

The need for our resources to be able to cover energy needs over an elongated period of time is important because we have seen historical, and projected instances of low renewable output that could create havoc for reliability were there not a sufficient amount of firm capacity to cover energy needs. For instance, recently customers in Oahu were asked to reduce use of electricity to avoid rolling blackouts across Oahu due to a shortage of reserve generation capacity.[5] Two large generating units at Waiau Power Plant went offline, and repairs were not expected to be completed by the end of the day. Heavy cloud cover and rainy conditions reduced the production from solar energy systems and prevented battery energy storage systems from charging to full capacity. As a result, Hawaiian Electric began load shedding in various areas around the island to avoid a more widespread outage or damage to the electric system from an imbalance of demand versus available generation.

Further, the Moon Shoot study[6] by GridLab, emphasized the importance of firm dispatchable generation to support a clean energy policy. The study noted that short storage duration batteries (typically 4 to 10 hours) can provide a significant amount of capacity for reliability, but they cannot be the only capacity resource on the system (unless systems are upsized in terms of solar and wind resources, or capacity expansions are planned through a regional optimization approach). There may be long periods—potentially spanning multiple days—where solar and wind are unavailable, requiring other resources (such as hydrogen capacity) to be available in these times. During this time, even relatively long, 10-hour duration battery storage does not bridge the gap between periods of renewable production and demand.

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[5] https://www.hawaiianelectric.com/update-rolling-oahu-outages-initiated-customers-asked-to-reduce-use-of-electricity.
[6] The Moonshot 100% clean electricity study:
Assessing the tradeoffs among clean portfolios with a PNM case study, Grid Lab
https://gridlab.org/moonshot-study/.

In conclusion, energy adequacy analysis is a critical tool in resource planning. It helps ensure that we have a diverse and resilient energy portfolio capable of meeting demand. This not only ensures the continuous supply of power but also contributes to the broader goals of affordability, carbon reduction and job creation.

IV. THE IMPORTANCE OF FIRM DISPATCHABLE RESOURCES IN OUR PREFERRED PLAN

As we work to decarbonize our system, our models indicate the need for the addition of approximately 3,600 MWs of cumulative firm dispatchable resources between 2027 and 2040 to ensure long-duration, affordable energy when our intermittent renewables are not able to fully meet our customers' needs. Of this modeled need, 2,244 MWs of firm dispatchable resources are needed by 2030. These resources are split between 748 MWs in 2027, 748 MWs in 2028, and 748 MWs in 2030. Approximately 374 MWs of the 2028 need is located on our re-optimized Sherco Generation tie line.

We note that the Commission is considering firm dispatchable resources additions in Docket No. E002/CN-23-212. Additional firm dispatchable resources above 800 MWs have bid into the acquisition proceeding to serve our up to 800 MW need identified in our 2019 Plan. As noted here, firm dispatchable resources provide numerous benefits, including near-instant availability, making them ideal for peak power supply and when intermittent wind and solar generation are not producing energy.

The value of firm dispatchable resources and fuel diversity becomes evident during periods of extreme weather. During the 2019 Plan, it was observed that firm dispatchable resources were crucial during severe cold spells when wind resources underperformed. Even with a hypothetical doubling of wind output, there were periods of low renewable output. Hence, having diverse resources is essential to meet customer needs during such events. A diverse mix of firm dispatchable resources ensures our ability to provide reliable electric service under all conditions. With the increasing frequency of extreme weather events, it is crucial to manage the transformation of our generation portfolio while preserving system reliability and stability. Though our nuclear units remain a major source of reliable, carbon-free generation for our system, our modeling shows a need for additional firm dispatchable generation.

Extreme events can span all or nearly all of MISO's footprint, limiting the ability to rely on the broader MISO system in times of need. To meet the shortfall in the output of variable resources; at such times, we may have to rely on our resource diversity and our dispatchable generation, including units fueled by natural gas and fuel oil. With the increasing frequency of extreme weather events, such as the 2019 polar vortex and

Winter Storm Uri in 2021, it is crucial to manage the transformation of our generation portfolio while preserving system reliability and stability. Any disruption in electric service during similar future events could have serious impacts on our customers, public safety and to overall grid operations.

In sum, from a high-level capacity and reliability standpoint, the importance of firm, dispatchable resources in our energy strategy is undeniable. As we transition towards a more sustainable energy future, these resources provide the reliability and stability necessary to ensure uninterrupted service under all conditions. While advancements in transmission technologies, renewable energy sources, and energy storage resources are promising, they cannot at this time fully replace the need for firm dispatchable resources due to their current technological maturity, regulatory complexities, and the challenges in large-scale deployment. Therefore, a balanced approach that includes a diverse mix of firm, dispatchable resources, is crucial in meeting the growing energy demand while also progressing towards decarbonization.

VI. INERTIAL FLOOR STUDY

In addition to considering the value of various resources from a high-level capacity and reliability view, the Company is assessing the electrical engineering impacts of moving from a system built around large, centrally located baseload units to one based more on remotely located renewable generators. Studies that the Company and others have conducted show that the inertia historically provided by these baseload units is crucial to help the system oscillations dampen out. To help inform decisions for future generation transformation from traditional coal-based generation, the Company's Transmission Planning engineers performed a study to evaluate the NSP system's transient stability response with all of the baseload coal generation in the region offline and replaced by renewable generation (wind and solar) and other thermal generation. Unlike traditional MISO generator replacement studies, this study considers not only what happens to our system as we retire Company-owned coal generation but also potential retirements of neighboring coal generation. At this time, MISO only studies system impacts of unit retirements based on unit-specific requests made by the owners of such units. However, we understand that the vast majority of utilities within MISO are considering similar renewable initiatives to the Company. Therefore, while MISO's studies currently reflect the transmission system as being reliable and stable, they do not provide a forward-looking regional assessment of stability as coal retirements continue.

We include as an attachment to this appendix, our NSP Power System Inertial Floor Study Report, showing how the grid would perform in the absence of traditional baseload generation, mainly coal and nuclear. This Inertial Floor study is run annually to update the analysis and evaluate the impacts to our system reliability, system stability, angular stability and inertia. This analysis allows us to determine the necessary levels of spinning mass and/or dispatchable generation necessary to keep the system stable and reliable to serve our customers.

Our study shows that inertia is crucial to help the system remain stable, and as we and other owners of baseload generation in the region retire those units, we begin to see regional stability issues. This demonstrates that it will be critical that we acquire resources capable of providing inertia as we retire our coal-fleet.

VI. CONCLUSION

Preparation and planning are key to delivering reliable power to our customers. As a Company, we take this responsibility seriously. Recent events have shown that it is important to plan for how we can provide electricity to our customers under all conditions. In addition to planning to meet our planning obligations without reliance on MISO, we have taken steps to further refine our energy adequacy analysis. We conducted energy adequacy back casting analysis to ensure our system has the reliable energy it needs to serve all customers at every hour of every day. We also examined the inertial floor of our system to assess how the grid would perform in the absence of traditional baseload generation. Our studies go beyond traditional EnCompass modeling to verify the need for firm dispatchable resources and inertia to ensure reliable service for our customers. Our Preferred Plan satisfies these concerns and will provide for the reliability our system needs to adequately ensure continued service to our customers.

NSP Power System
Inertial Floor Study Report

Performed by:
Craig Wrisley

Transmission Planning
July 21, 2023

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Certification

I hereby certify that this report was prepared
by me or under my direct supervision and that
I am a duly Licensed Professional Engineer under the
Laws of the state of Minnesota

Craig Wrisley
7/17/2023
License# 54948

Executive Summary

This analysis was performed to determine how the grid would perform in the absence of traditional baseload generation, mainly coal and nuclear. Baseload generators are units online or operating most hours of the year. To help inform decisions for future generation transformation from traditional coal based, Transmission Planning engineers performed a study to evaluate the NSP system transient stability response with all of the baseload coal generation offline. Renewable generation (wind and solar) and natural gas Combined Cycles (CC) and Combustion Turbines (CT) generation are used to replace the baseload generation that has been turned offline. This study is a stability only look – system transfer capability and resource capacity analyses are out of the work scope of this study. However, all the problems shown in the power flow models are documented.

This study examines grid performance in the absence of traditional baseload generation. The following Table 1 shows theses baseload generators and the amount of power that needs to be replaced by another type of generation.

Table 1

Baseload Generator	2027 SHAW	2027SUM
SherCo #1 (Coal)	730 MW	730 MW
SherCo #2 (Coal)	730 MW	730 MW
SherCo #3 (Coal)	928 MW	928 MW
King (Coal)	197 MW	560 MW

Based on the analysis results performed in this study, there are several potential system issues observed. The observations are listed below:

- Inertia is crucial to help the system oscillations dampen out
- Existing and proposed CCs do help stabilize the power system but are not enough to hold the system stable during all potential future generation retirement or during low renewable power situations when wind and solar are not available (i.e. night time with no wind).

Scenarios Analyzed

Summer Shoulder Average Wind, and Summer Peak scenarios are analyzed in this study. Renewables in the NSP system are modeled at seasonal generation levels; Solar at 50% for Summer Peak, 50% for Summer Shoulder Average Wind, Wind at 14.8% for Summer Peak, 48% for Summer Shoulder Average Wind.. CCs in the study area are turned on to full capacity as required to provide system stability. NERC requires Transmission Planners to evaluate the grid including under prior outage conditions. Key generation outages are assessed in the study:

- Scenario 1: Turn OFF MP Boswell Unit 3 and 4 coal plant
- Scenario 2: Turn OFF GRE Coal Creek Unit 1 and 2 coal plant
- Scenario 3: Turn OFF OTP Bigstone Unit coal plant
- Scenario 4: Turn OFF Nextera Duane Arnold nuclear plant

- Scenario 5: Turn OFF MEC Ottumwa coal plant
- Scenario 6: Turn OFF MEC George Neal Unit 3 and 4 coal plant
- Scenario 7: Turn OFF MEC Council Bluffs Unit 3 and 4 coal plant

NSP load information is shown in following Table 2.

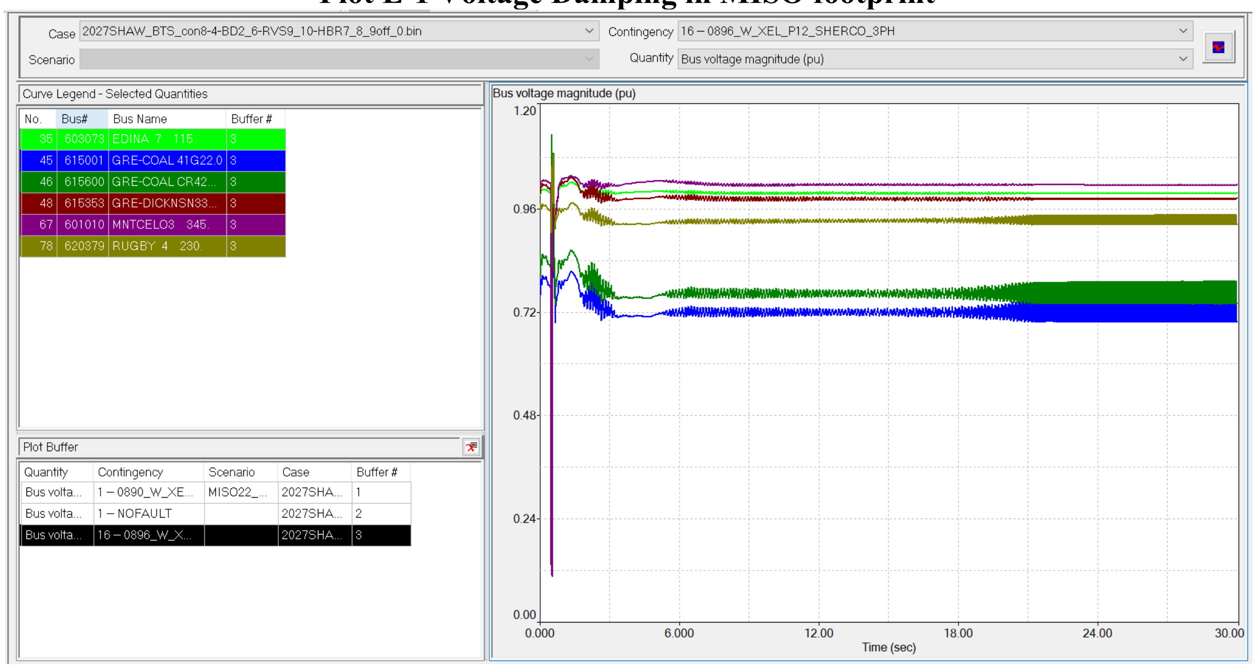
Table 2
NSP Load Level and Thermal Generation

Year	Season	Load Level
2027	Summer Shoulder Average Wind	6517 MW
2027	Summer Peak	9309 MW

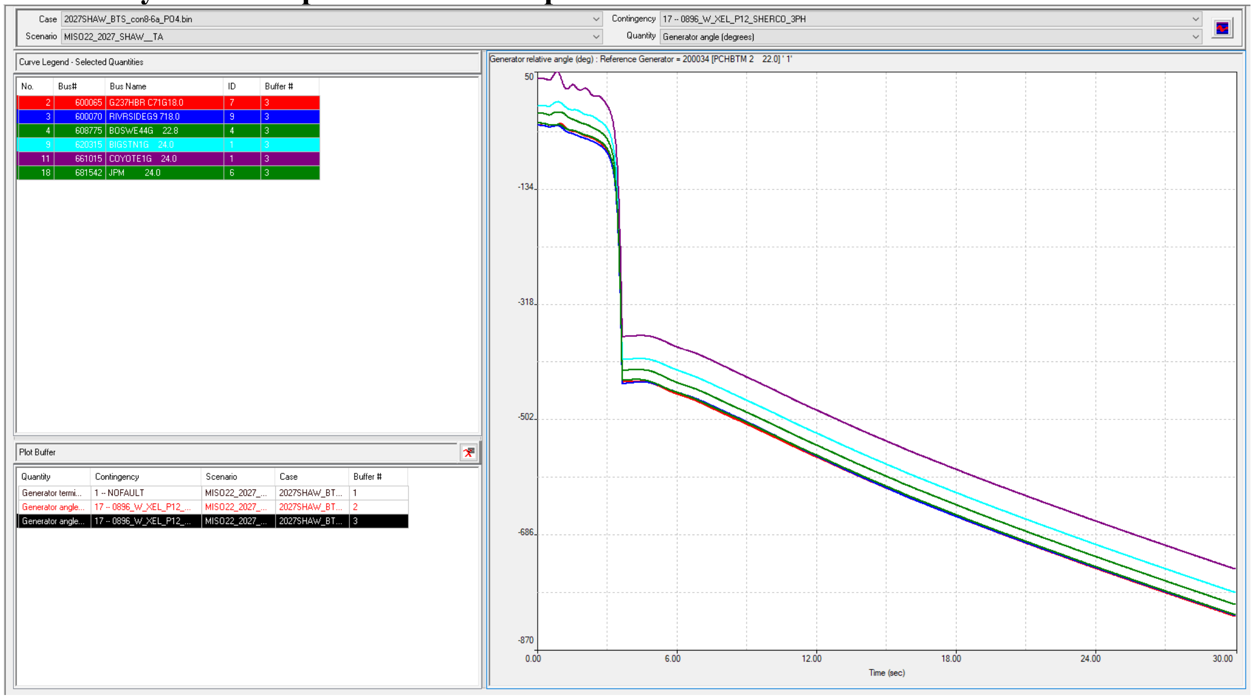
Transient Stability Simulation Results

System voltage damping issues are shown on buses in all disturbances tested with generation below the levels indicated for damping results in the report.

Plot E-1 Voltage Damping in MISO footprint



Plot E-2 System Collapse in MISO Footprint



Introduction

This analysis was performed to determine how the grid would perform in the absence of traditional baseload coal generation. Baseload generators are units online or operating most hours of the year. To help inform decisions for future generation transformation from traditional coal based, Transmission Planning engineers performed a study to evaluate the NSP system transient stability response with all of the baseload coal generation offline. Renewable generation (wind and solar) and natural gas Combined Cycles (CC) and Combustion Turbines (CT) generation are used to replace the baseload generation that has been turned offline. This study is a stability only look – system transfer capability and resource capacity analyses are out of the work scope of this study. However, all the problems shown in the power flow models are documented.

Assumptions

This study is performed utilizing Powertech TSAT version 21.0, and based on the MISO MTEP 2022 dynamics package. MISO MTEP 2022 series, year 2027 models are selected as the starting models; no substantial load growth is assumed in this study. Renewables listed on the MISO Renewable Sitting Location list are selected based on the Tier 1 and Tier 2 order. Only Renewables located in Iowa, South Dakota, North Dakota, Minnesota, and Wisconsin are selected. All generations are modeled as lumped generator, and all wind generators are modeled as type 3 models, and all solar generations are modeled as type 4 models.

Potential Limitations

Software

Powertech TSAT version 21.0 is utilized to perform the study. The existing TSAT software version is designed and manipulated based on today's power system – strong inertial support and high reliability margin– which generates great steady state results and provides very useful information for voltage stability and transient stability studies. However, due to functional limitations and the lack of detailed load and DER modeling information, the existing TSAT program can't predict precisely where the stability issue will start to occur in a high penetration, low inertia system.

Model

The study models originated from the MISO MTEP 2022 package models and are based on 2027 load levels. Existing dynamic load models included in the MTEP package are used in this study, but future, more detailed dynamic load modeling, could significantly change the system stability in a low inertia system. Utility size solar farms are included and modeled, but the smaller distributed solar farms (DER) are not modeled in the study. The DER modeling and coordination can play a very important role in future high penetration and low inertia system.

Unpredictable new technologies (Technology stabilize the system) and/or load (such as system wide loads, new policy making on Electric Vehicles, etc) are not analyzed in this study. However, these factors could change the system condition dramatically. The study is based on all facilities functioning correctly, and all protection schemes correctly coordinated. System coordination will be even more important and challenging in the future, than compared to the current system.

All the wind and solar farms are lumped as a single generator connecting directly to the point of interconnection (POI); detailed connector system is not modeled. The wind and solar farm connector system consumes reactive power which helps to deliver and transform the generated wind power to the rest of the power system; the lumped generator doesn't demonstrate the reactive power consumption in the connector system. Therefore, better reactive capacity is shown in the lump generator modeling.

1 Models and Assumptions

2.1.1 Models Utilized

This study is performed utilizing Powertech TSAT version 21.0 and based on the MISO MTEP 2022 dynamics package. MTEP 2022, year 2027 models are selected as the starting models. No substantial load growth is assumed in this study.

2.1.2 Model Development

MTEP 2022, year 2027 models are selected as the starting models. No substantial load growth is assumed in this study. Renewables listed on the MISO Renewable Sitting Location list are selected based on the Tier 1 and Tier 2 order and IRP filing. All renewables added to the model are listed in Table-3.

Table-3 Renewable Generation Added

Description	Capacity (MW)	Gen Bus # Y5	Area Number	Area Name	Bus Name
Lake Benton I:WT1 143 - Repowered	26.80	600056	600	XEL	BRI311_1W
Lake Benton I:WT1 143 - Repowered	26.80	600076	600	XEL	BRI312_1W
Lake Benton I:WT1 143 - Repowered	26.80	600079	600	XEL	BRI312_2W
Lake Benton I:WT1 143 - Repowered	26.80	600080	600	XEL	WPP93-MN
Lake Benton II:EXIS - Repowered	14.79	600081	600	XEL	BRI321_1W
Lake Benton II:EXIS - Repowered	14.79	600082	600	XEL	BRI321_2W
Lake Benton II:EXIS - Repowered	14.79	600083	600	XEL	BRI321_3W
Lake Benton II:EXIS - Repowered	14.79	600084	600	XEL	BRI321_4W
Lake Benton II:EXIS - Repowered	14.79	600085	600	XEL	BRI321_5W
Lake Benton II:EXIS - Repowered	14.79	600086	600	XEL	BRI322_1W
Lake Benton II:EXIS - Repowered	14.79	600087	600	XEL	G443 BRI323W
Lakota Ridge:NMO1 - Repowered	11.20	600088	600	XEL	BRI323_3W
Shaokatan Hills:6150 - Repowered	11.80	600090	600	XEL	G397 THLEN W
Blazing Star 2	200.00	600179	600	XEL	J587_GEN1
Nobles Wind 2	250.00	600185	608	MP	J512_GENBUS
RRF MISO PV: Minnesota - 9	60.00	601002	600	XEL	ADAMS 3
RRF MISO Wind: Minnesota - 5	96.08	601002	600	XEL	ADAMS 3
RRF MISO PV: Minnesota - 15	60.00	601010	600	XEL	MNTCELO3
RRF MISO PV: Minnesota - 1	60.00	601051	600	XEL	HMPT CNR3
RRF MISO HYB(HB): Minnesota - 1	190.85	601074	600	XEL	CRANDAL 3
RRF MISO PV: Minnesota - 10	60.00	601074	600	XEL	CRANDAL 3
RRF MISO PV: Minnesota - 16	23.42	601077	600	XEL	HAWKSNEST 3
RRF MISO Wind: Minnesota - 2	28.00	602003	600	XEL	BLUEETA5
RRF MISO PV: Wisconsin - 14	11.00	602033	600	XEL	HYDROLN5
J569	100.00	602039	600	XEL	ROCK CO5

Description	Capacity (MW)	Gen Bus # Y5	Area Number	Area Name	Bus Name
RRF MISO PV: South Dakota - 1	41.22	603009	600	XEL	GRANT 7
RRF MISO PV: Minnesota - 6	60.00	603010	600	XEL	LKYNKTN7
RRF MISO PV: Minnesota - 8	54.00	603134	600	XEL	BUFFRID7
Badger Hollow Solar 1	200.00	603172	600	XEL	WYOMING7
Badger Hollow Solar 2	100.00	603172	600	XEL	WYOMING7
RRF MISO PV: Minnesota - 7	60.00	603180	600	XEL	CHANRMB7
RRF MISO PV: Wisconsin - 8	26.00	603202	600	XEL	THREE LAKES7
RRF MISO Wind: North Dakota - 5	12.00	608602	608	MP	SQBEAST4
RRF MISO PV: Minnesota - 2	58.00	613060	600	XEL	BYRON 3
RRF MISO Wind: Iowa - 5	65.00	613330	627	ALTW	RICE 5
RRF MISO PV: Minnesota - 13	22.00	615566	608	MP	GRE-WINGRIV4
RRF MISO Wind: Minnesota - 4	120.00	615648	600	XEL	GRE-CDRMTL23
RRF MISO Wind: North Dakota - 2	120.00	615901	615	GRE	GRE-STANTON4
RRF MISO Wind: North Dakota - 8	29.09	615907	615	GRE	GRE-RMSYCB14
RRF MISO Wind: North Dakota - 4	39.00	615908	615	GRE	GRE-RMSYCB24
RRF MISO PV: Minnesota - 12	20.00	618905	600	XEL	GRE-ELLSBOR7
RRF MISO PV: Minnesota - 4	13.00	619407	600	XEL	GRE-FSCHRHL7
RRF MISO PV: North Dakota - 2	18.00	620204	620	OTP	PELICN N T7
RRF MISO PV: North Dakota - 1	11.00	620259	620	OTP	ALICE 7
RRF MISO Wind: North Dakota - 6	11.00	620259	620	OTP	ALICE 7
RRF MISO PV: North Dakota - 3	78.24	620290	620	OTP	HARVEY 4
RRF MISO PV: North Dakota - 4	48.80	620290	620	OTP	HARVEY 4
RRF MISO Wind: North Dakota - 7	52.00	620290	620	OTP	HARVEY 4
J437	150.00	620322	620	OTP	BSSOUTH4
RRF MISO Wind: South Dakota - 1	61.00	620325	620	OTP	BROWNSV4
Flying Cow Wind	150.00	620417	620	OTP	BSSOUTH3
Deuel Harvest Wind	310.00	620417	620	OTP	BSSOUTH3
Dakota Range III Wind	151.80	621003	620	OTP	J488 G
Codington County Wind	300.00	621102	620	OTP	J436 DK RNG1
RRF MISO Wind: Minnesota - 1	16.00	658114	620	OTP	APPLETN7
RRF MISO Wind: North Dakota - 3	14.00	661030	661	MDU	STEIN 7
RRF MISO Wind: South Dakota - 2	49.46	661038	652	WAPA	GLENHAM4
Merricourt Wind	150.00	661093	661	MDU	MERRCRT4
RRF MISO Wind: North Dakota - 1	40.00	661094	661	MDU	WISHEK 4
J718	49.98	680413	680	DPC	CHERRY_8
RRF MISO PV: Wisconsin - 12	43.00	681534	680	DPC	APL RVR5
GRE Ramsey	503.00	615335	615	GRE	GRE-RAMSEY
Minnesota Energy Connection	2200	601011	600	XEL	SHERCO 3

Description	Capacity (MW)	Gen Bus # Y5	Area Number	Area Name	Bus Name
King Transmission Connection	560	601014	600	XEL	AS KING3

Summer Shoulder Average Wind, and Summer Peak scenarios are analyzed in this study. Renewables in the NSP system are modeled at seasonal generational levels in both models; Solar at 50% for Summer Peak, 31% for Summer Shoulder Average Wind, Wind at 14.9% for Summer Peak, 50% for Summer Shoulder Average Wind. For No renewable cases, Wind and Solar were reduced to 0MW and 70% MVAR availability to simulate the Wind Free and Q at night functionality of the new inverter types. CCs in the study area are turned on to full capacity as needed to provide stability in each scenario. NSP load information is shown in Table-4.

Table-4 NSP Load Level and Thermal Generation Level

Year	Season	Load Level
2027	Summer Shoulder Average Wind	6517 MW
2027	Summer Peak	9309 MW

Baseload generators turned off are listed in Table-5.

Table-5 Baseload Generation Turned off

Bus Name	Bus Number	2027 SHAW	2027SUM
600000	SHERC31G 24.000	730 MW	730 MW
600001	SHERC32G 24.000	730 MW	730 MW
600002	SHERC33G 26.000	928 MW	925 MW
600006	KING 31G 20.000	552 MW	552 MW

CC generations turned on are listed in Table-6.

Table-6 Shoulder Average Wind Combined Cycle and Combustion Turbine Generation Turned on

Gen PSSE Bus	Gen Name	Pmax	SHAW Base	SHAW Prior Outage	SHAW Synch Cond Prior Outage	SHAW No Renewable	SHAW No Renewable Prior Outage
600993	Lyon Co CT	800					
600022	Blue Lake 1	39					
600023	Blue Lake 2	39					
600024	Blue Lake 3	36					
600025	Blue Lake 4	39					
600043	Blue Lake 7	151				X	X
600044	Blue Lake 8	151				X	X
600995	Inverhills CT2	200					
600996	Inverhills CT1	225					X
600012	Black Dog 2	115				X	X
600164	Black Dog 6	214				X	X
600065	Highbridge 7	162		X		X	X
600066	Highbridge 8	162				X	X
600067	Highbridge 9	226				X	X
600007	Riverside 7	160		X		X	X
600070	Riverside 9	158				X	X
600071	Riverside 10	158				X	X
600046	MEC ST	330				X	X
600047	MEC CT1	188.5				X	X
600172	MEC CT2	186				X	X

Table-6 Summer Combined Cycle and Combustion Turbine Generation Turned on

Gen PSSE Bus	Gen Name	Pmax	SUM Base	SUM Prior Outage	SUM Synch Cond Prior Outage	SUM No Renewable	SUM No Renewable Prior Outage
600993	Lyon Co CT	**800**		X	X	X	X
600022	Blue Lake 1	**39**		X	X	X	X
600023	Blue Lake 2	**39**		X	X	X	X
600024	Blue Lake 3	**36**		X	X	X	X
600025	Blue Lake 4	**39**		X	X	X	X
600043	Blue Lake 7	**151**	X	X	X	X	X
600044	Blue Lake 8	**151**	X	X	X	X	X
600995	Inverhills CT2	**200**					
600996	Inverhills CT1	**225**		X	X	X	X
600012	Black Dog 2	**115**	X	X	X	X	X
600164	Black Dog 6	**214**	X	X	X	X	X
600065	Highbridge 7	**162**	X	X	X	X	X
600066	Highbridge 8	**162**	X	X	X	X	X
600067	Highbridge 9	**226**	X	X	X	X	X
600007	Riverside 7	**160**	X	X	X	X	X
600070	Riverside 9	**158**	X	X	X	X	X
600071	Riverside 10	**158**	X	X	X	X	X
600046	MEC ST	**330**	X	X	X	X	X
600047	MEC CT1	**188.5**	X	X	X	X	X
600172	MEC CT2	**186**	X	X	X	X	X

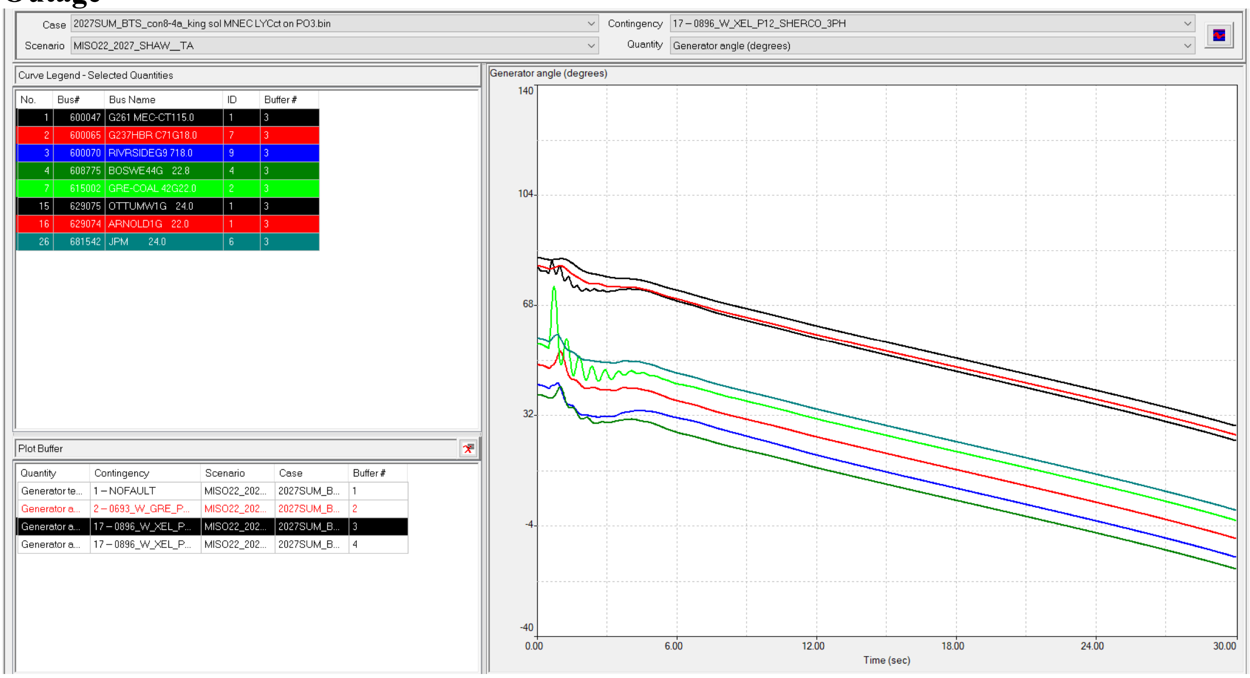
2.1.3 Modeling Assumption

Only Renewables located in Iowa, South Dakota, North Dakota, Minnesota, and Wisconsin are selected. All wind generations are model as type 3 models, and all solar generations are modeled as type 4 models. Solar at 50% for Summer Peak, 31% for Summer Shoulder Average Wind, Wind at 14.9% for Summer Peak, 50% for Summer Shoulder Average Wind. For No renewable cases, Wind and Solar were reduced to 0MW and 70% MVAR availability to simulate the Wind Free and Q at night functionality of the new inverter types.

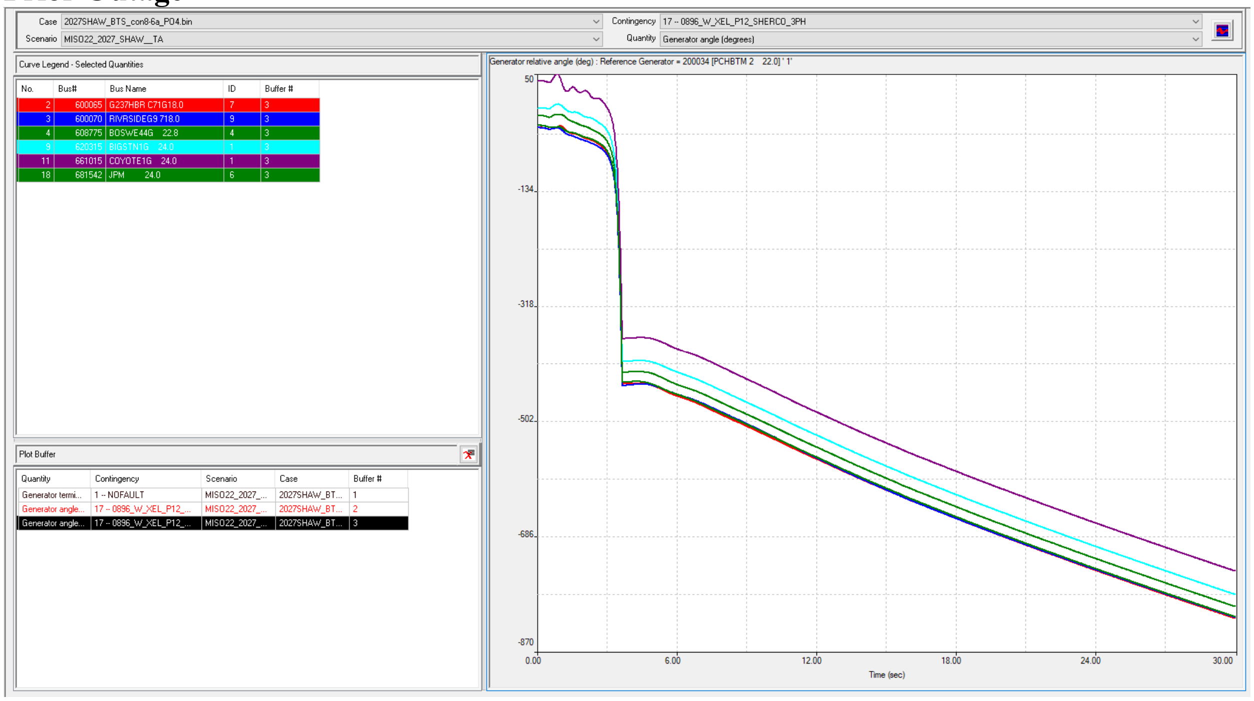
2.1.4 Issues Shown in Power Flow Models

Potential generation stability issues were identified in SHAW, no renewable prior outage cases and SUM prior outage and no renewable cases. The instability is indicated by the generator rotor angles exceeding 300 degrees, which is indication of angular separation from the grid, which would lead to generator tripping and likely islanding of the system where small pockets of the system are isolated by protection tripping. The SUM prior outage cases did not exceed 300 degrees in the 30 second analysis duration, but did showed degrading angle and no indication of recovery. Plots E3 and E4 show examples of the generator angle instability.

Plot E-3 Generator Angular Instability Summer with Synchronous Condenser Prior Outage



Plot E-4 Generator Angular Instability Shoulder Average Wind No Renewable Prior Outage



2.1.5 Prior Outages

Three prior outages are selected to test more stressed system conditions. The selected prior outages are tested for each season, and listed below:

- Scenario 1: Turn OFF MP Boswell Unit 3 and 4 coal plant
- Scenario 2: Turn OFF GRE Coal Creek Unit 1 and 2 coal plant
- Scenario 3: Turn OFF OTP Bigstone Unit coal plant (Summer Only, Unit Off in Shoulder Base Case)
- Scenario 4: Turn OFF Nextera Duane Arnold nuclear plant
- Scenario 5: Turn OFF MEC Ottumwa coal plant
- Scenario 6: Turn OFF MEC George Neal Unit 3 and 4 coal plant
- Scenario 7: Turn OFF MEC Council Bluffs Unit 3 and 4 coal plant

2 Stability Analysis

MISO MTEP 2022 Transient Dynamic package is used to conduct the transient stability analysis. Three phase faults with normal clearance time and single line to ground faults with a stuck breaker are tested for major 345 kV substations, transmission lines in Twin Cities and neighboring areas. Selected 345 kV bus voltages and transmission line power flow in Twin Cities and neighboring areas are monitored and plotted. The disturbances studied are listed in Table-7:

Table-7 Disturbances Simulated in the Study

YELLOW HIGHLIGHT DENOTES PROTECTED CEII DATA

Name	Description

Name	Description

3 Analysis Results

Stability simulation results are summarized in Table-8: **YELLOW HIGHLIGHT DENOTES PROTECTED CEII DATA**

Table-8 Stability Analysis Summary

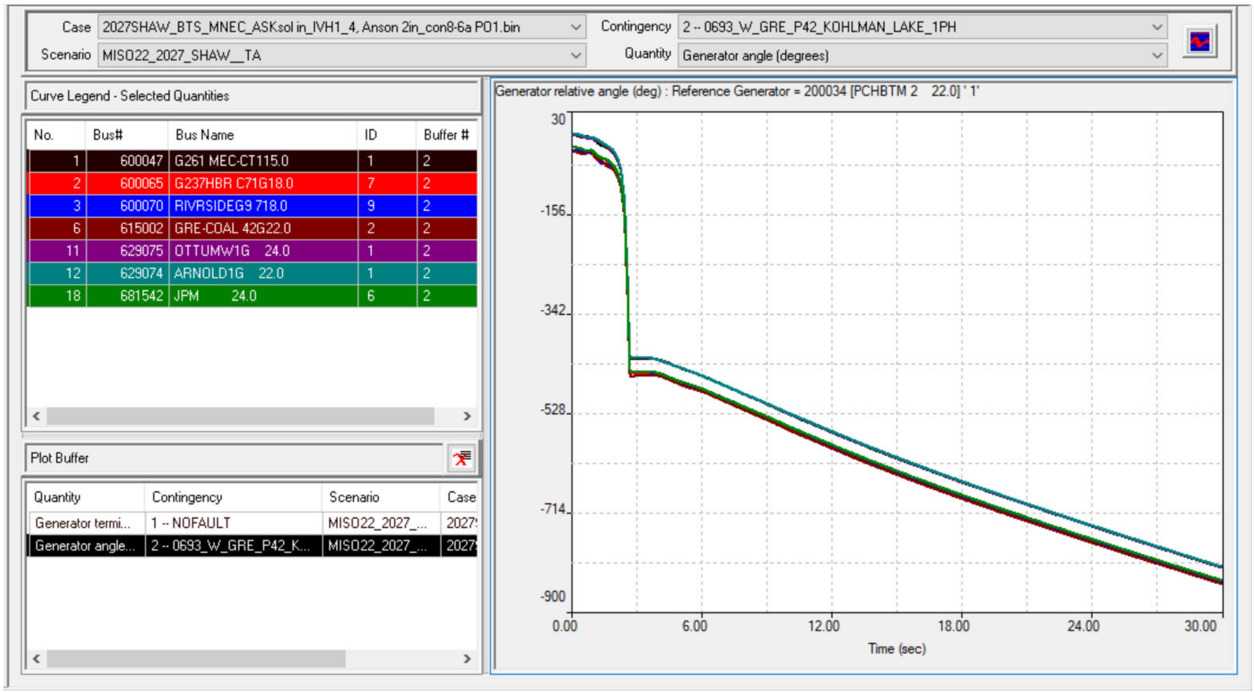
Contingency	Description	2027 SHAW Base	2027 SHAW Prior Outage	2027 SHAW Synch Cond Prior Outage	2027 SHAW synch cond No Renewable	2027 SHAW synch cond No Renewable Prior Outage	2027 SUM Base	2027 SUM Prior Outage	2027 SUM Synch Cond Prior Outage	2027 SUM synch cond No Renewable	2027 SUM synch cond No Renewable Prior Outage
0693_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0857_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0860_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0865_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0866_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0867_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0868_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0879_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0890_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0891_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0892_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0893_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0896_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0898_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0920_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0922_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0927_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse

Contingency	Description	2027 SHAW Base	2027 SHAW Prior Outage	2027 SHAW Synch Cond Prior Outage	2027 SHAW synch cond No Renewable	2027 SHAW synch cond No Renewable Prior Outage	2027 SUM Base	2027 SUM Prior Outage	2027 SUM Synch Cond Prior Outage	2027 SUM synch cond No Renewable	2027 SUM synch cond No Renewable Prior Outage
0935_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0936_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0941_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0942_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0943_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0944_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
0945_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2199_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2217_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2218_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2219_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2229_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2238_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2242_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2257_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse
2277_redacted		Damping	Damping	Damping	Damping	Collapse	Damping	Collapse	Collapse	Collapse	Collapse

5 Analysis Results Discussion

2027 Shoulder Average Wind Case:

System generator angular stability issues are shown in the no renewable scenario on generators in the study area in all disturbances tested.



Summer Peak Case:

System generator angular stability issues are shown in the prior outage and no renewable scenario on generators in the study area in all disturbances tested.

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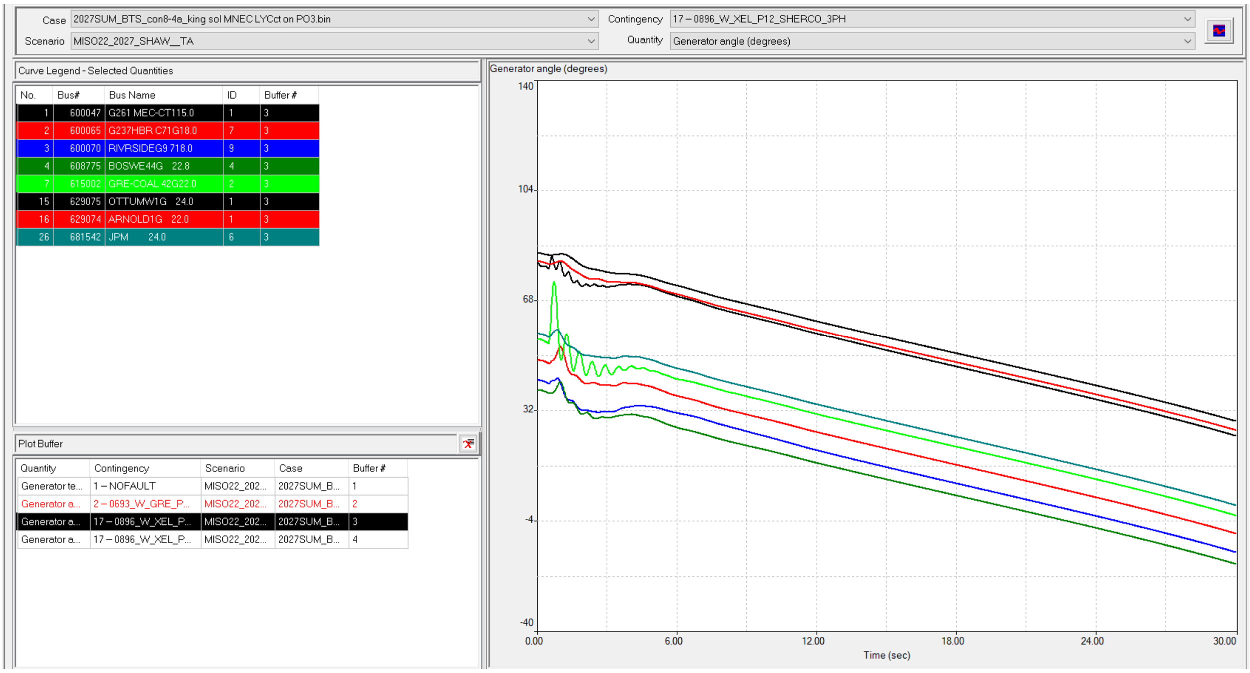


6 Observation

Based on the analysis results performed in this study, there are several potential system issues that have been observed. These observations are listed below:

- Inertia is crucial to help the system oscillations dampen out, but does not help angular stability.
  - Inertia can be provided by synchronous machines.
  - Angular stability can only be solved by using real power on the other side of the power transfer to reduce the angle.

Existing and proposed CCs do help stabilize the power system but are not enough to hold the system stable during all potential future generation retirement or during low renewable power situations.

APPENDIX E – LOAD AND DISTRIBUTED ENERGY RESOURCE FORECASTING

I. SUMMARY LOAD FORECAST DESCRIPTION

This appendix discusses the methodology we used in conjunction with this resource plan to forecast customer need, including the requirements specified in Minn. R. 7610.0320. This appendix documents our load and energy demand forecasting process. In addition, we have taken additional steps in this resource plan to model energy efficiency (EE) as a supply-side resource. Where relevant, we include explanations of these steps to provide transparency and explain how this base forecast correlates to the load and energy demand forecasting discussed in Chapter 3: Minimum System Needs, and Appendix F: EnCompass Modeling Assumptions and Inputs.

The Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic, and weather variables. We develop our sales forecasts for each major customer class in each state of our service area. The individual class forecasts for each state are summed to derive a total system sales forecast.

We convert the sales forecast into energy requirements at the generator level by adding energy losses. The forecasted losses are based on forecasted loss factors, which are developed by modeling actual historical losses. We develop a preliminary peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather, and then develop a final peak forecast by adjusting for electric vehicles, changes in large customer loads, and beneficial electrification. We provide a detailed discussion of the forecast methodology later in this appendix.

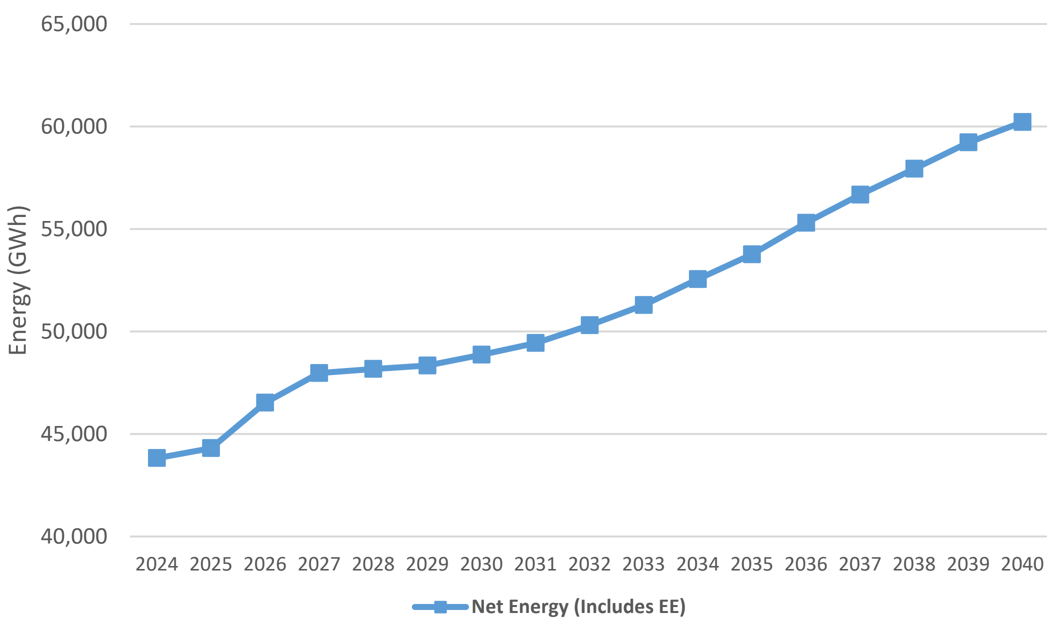
The forecasts themselves are based on projections of economic activity for our various service areas provided by IHS Global Insight, Inc. (Global Insight). Global Insight expects continued growth in key economic indicators. For example, for the Minneapolis-St. Paul metropolitan area, households are expected to increase at an average annual rate of 0.8 percent during the 2024-2040 planning period. Real per-capita personal income is expected to increase 1.9 percent per year on average, and employment is expected to gain an average of 0.4 percent per year. Minnesota real gross state product is expected to increase at an average annual rate of 1.8 percent.

A. Energy Forecast

1. Base Forecast

The base energy forecast increases at an average annual growth rate of 2 percent over the 2024 – 2040 planning period, net of modeled energy savings, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements[1] are expected to increase at an annual average of 1,025 gigawatt-hours (GWh), starting with 43,823 GWh in 2024 to 60,215GWh in 2040. See Figure E-1 below.

Figure E-1: NSP System Total Median Net Energy (GWh)
(Includes Adjustment for EE)



The projected 2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years due, primarily, to large new data center loads and acceleration in the adoption of Electric Vehicles. After adjusting for unusual weather, electric energy requirements increased at an average annual rate of 0.2 percent from 2019 to 2022.[2]

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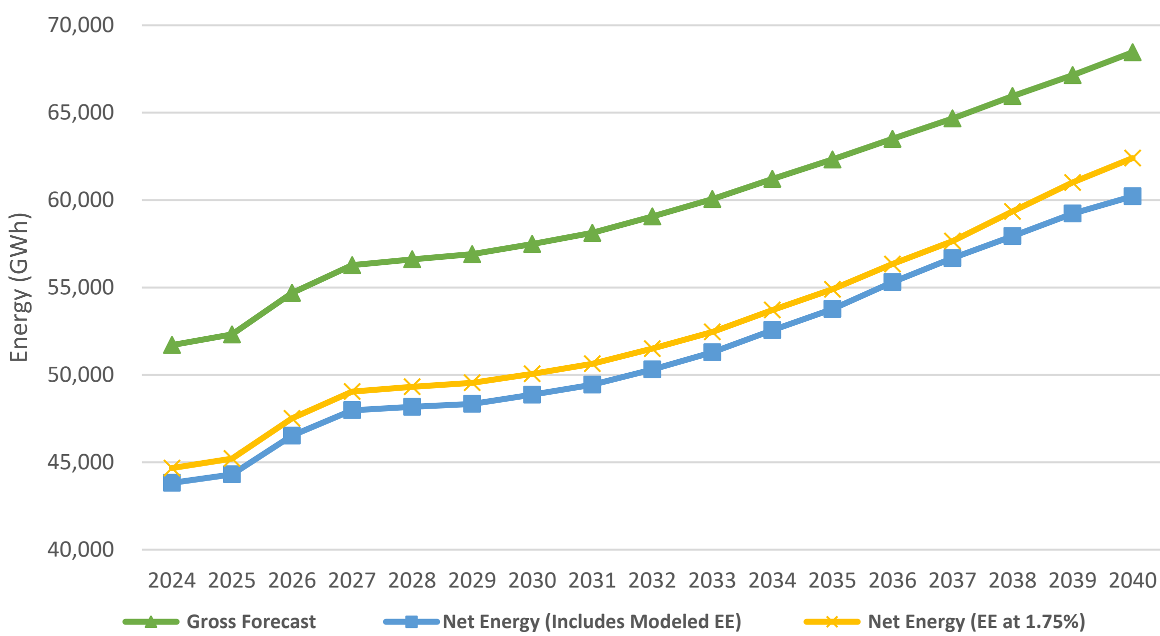
[1] Gross of rooftop solar generation. Solar generation was modeled as a resource instead of netting against energy requirements.
[2] This data comes from the Company's EFF database, which is our system of record for sales and customer accounts.

2. *Modifications for Use in EnCompass*

To be consistent with the modeling approach for EE in the last IRP, we continue to model energy efficiency as a supply-side resource. This required that we adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of energy savings to the end of the Planning Period. This resulted in an NSP System Gross Energy Requirements forecast. In a separate process, we formulated annual EE savings amounts into "Bundles" that we made available in the EnCompass model along with other supply-side resources. These adjustments are shown in Figure E-2 below.

Figure E-2: Gross Energy Requirements Forecast Compared to Net Energy Requirements Forecast



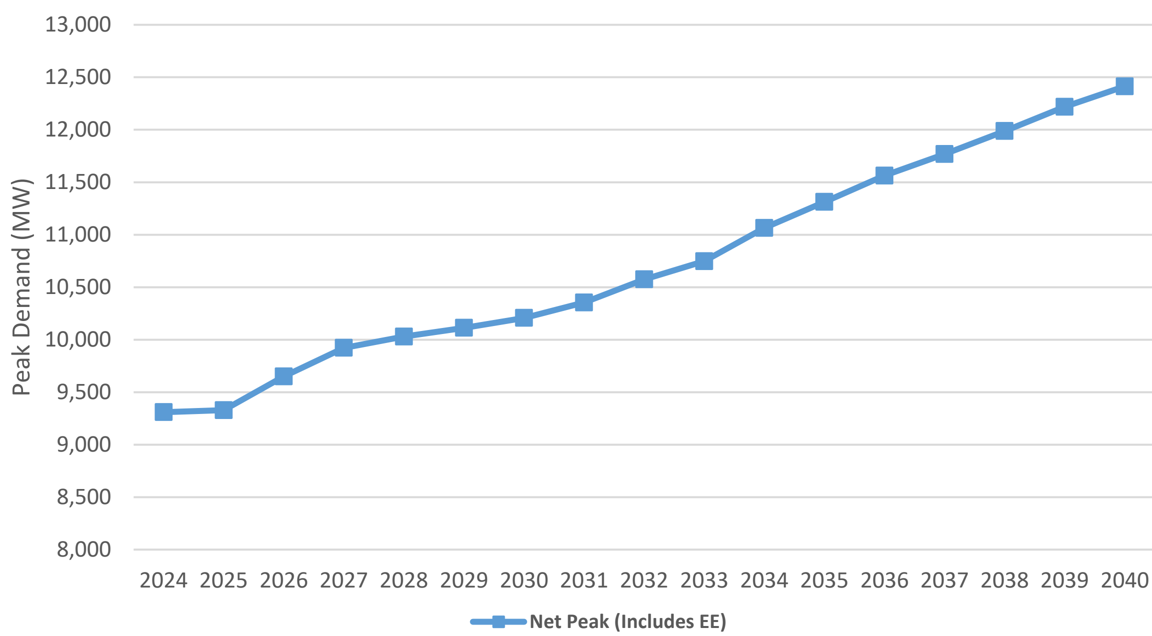
We discuss the EE Bundle modeling further later in this appendix, as well as in Appendix F: EnCompass Modeling Assumptions and Inputs, and Appendix H: Resource Options. Appendix J: Distributed Energy Resources contains detail on how the EE bundles were developed.

B. System Peak Demand Forecast

1. Base Forecast Methodology

During the 2024 – 2040 planning period, the base case peak forecast increases at an average annual growth rate of 1.8 percent. As demonstrated in Figure E-3 below, annual summer peak demand increases at an average of 194 MW each year, starting with 9,309 MW in 2024 to 12,414 MW in 2040.

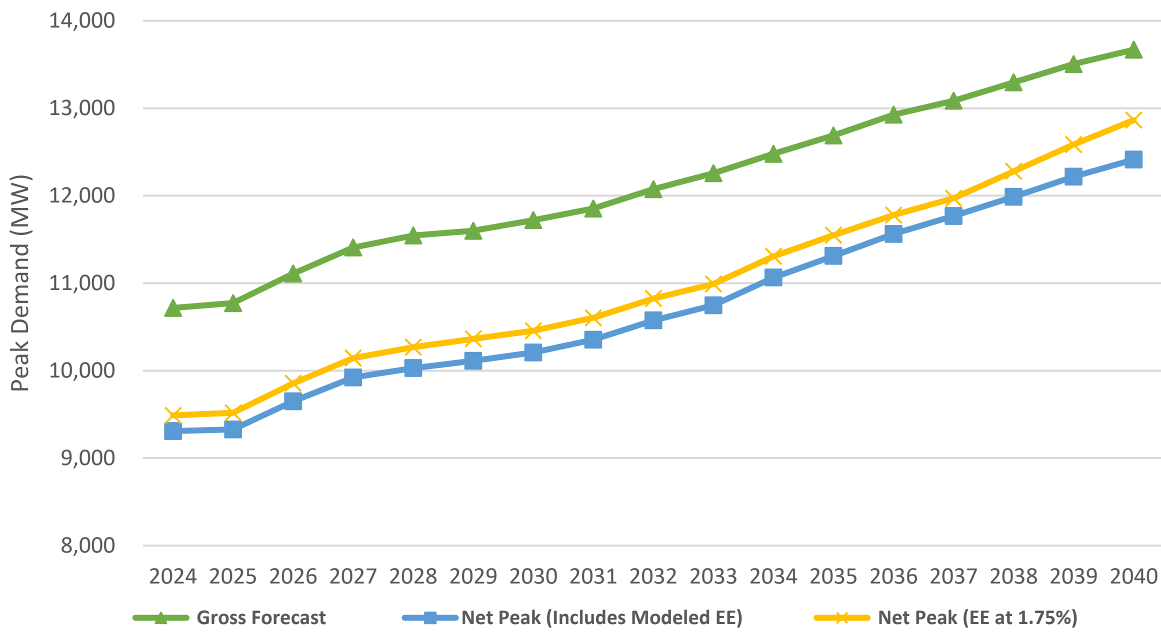
Figure E-3: NSP System Median Base Summer Peak Demand (MW) (Includes modeled EE Adjustment)



2. Modifications for Use in EnCompass

For modeling peak summer demand levels in EnCompass, we took the same approach as noted in reference to the energy forecasts. Again here, for EnCompass modeling purposes, we start with the base forecast and remove EE adjustments to reflect gross load. This process enables us to model the system considering EE as a supply-side resource.

Figure E-4: Gross Peak Demand Forecast Compared to Net Peak Demand Forecast



The remainder of this appendix discusses the energy and peak load forecasting methodologies, assumptions, analytics, adjustments, etc. to derive the System Energy Forecast presented in Part A.1 and Figure E-1 and the System Base Peak Demand Forecast presented in Part B.1 and Figure E-3.

C. Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at the jurisdictional level for the Residential, Small Commercial and Industrial sectors for all jurisdictions, Large Commercial and Industrial sector for all NSPM jurisdictions, and the Minnesota Public Street and Highway Lighting and Public Authority sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document.

For the remaining, more static customer classes – Large Commercial and Industrial (NSPW), Public Street and Highway Lighting, Public Authority, and Interdepartmental – in all states but Minnesota we use trend analysis or a simple historical average. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed by modeling actual historical loss factors and estimating losses for the first forecast year (2023). These factors are held constant over the forecast period.

We updated our peak forecast methodology to better account for the potential peak shifting due to future adoption of Distributed Solar Generation (DG Solar), managed and unmanaged Electric Vehicle (EV) charging, and Beneficial Electrification (BE). These technologies will, on net, shift load from typical summer peak hours (afternoon/early evening) into late evening or, in the case of managed EV's, early morning. The prior monthly peak modeling approach could not account for time shifting; therefore, the static assumption would be that NSP will continue to peak at the same time as the historical series being modeled.

The current "8760" peak modeling approach uses Metrix LT to scale unique hourly profiles for each hour in the year. Specifically, we perform modeling for Base energy,[3] EV, BE, DG Solar,[4] Large CI Data Centers, and Energy Efficiency using monthly energy assumptions for each specific component and on a state-by-state basis. The Base energy curve is also scaled to include a Base monthly peak demand outlook[5] that assumes no new technologies and no change in customer behavior from the present. All component curves are then aggregated, and the maximum hourly load by month is calculated. The resulting peaks largely align with the Company's old monthly modeling process for the first few years of the forecast timeframe. However, adoption of rooftop solar generation eventually pushes summer peaks later into the evening, and increased EV penetration with charge management programs moves peaks to 1:00 a.m. by the early 2040s.

[3] Base energy is an outlook for NSP consumption that assumes no change in customer behavior i.e. if consumer behavior remains unchanged from the present, and includes no forecast adjustments for EV, BE, DG Solar, new Large CI Data Centers, and Energy Efficiency.
[4] DG Solar does not include CSGs or solar that satisfies the 3 percent DSES legislation.
[5] Produced using a monthly regression model of NSP peak demand.

Once the NSP System peak demand forecast is complete,[6] a model is developed that relates the NSP System's non-MISO coincident peak (NCP) to the NSP System demand coincident with the Midcontinent Independent System Operator (MISO) system peak demand. In other words, the model was developed to calculate NSP's coincident peak (CP). The resulting relationship between the two series is referred to as the Coincidence Factor (CF), and is used to convert the NCP[7] to the CP forecasts used in Encompass modeling for this Resource Plan.

D. Forecast Adjustments

The demand and energy forecasts are developed using a number of assumptions described in this appendix, including Energy Efficiency (EE). NSP's methodology is unchanged from the 2019 and 2015 resource plans, and the process follows three distinct steps:

- Collect and calculate historical and current effects of EE on observed sales.
- Project the forecast using observed data with the impact of EE removed (i.e., increase historical sales to show hypothetical case without EE).
- Adjust the forecast to show the impact of all planned EE in future years and from continuing energy savings resulting from historical measures.

These EE adjustments are based on the Company's current Energy Conservation and Optimization (ECO) Triennial Plan goals, which were set using the savings level approved in the resource planning process. The Commission approved an average annual energy savings level of 780 GWh for all planning years in our 2019 Resource Plan.[8] Our most recent ECO Triennial filing[9] follows the approved level, and these EE impacts are shown below in Figure E-5.

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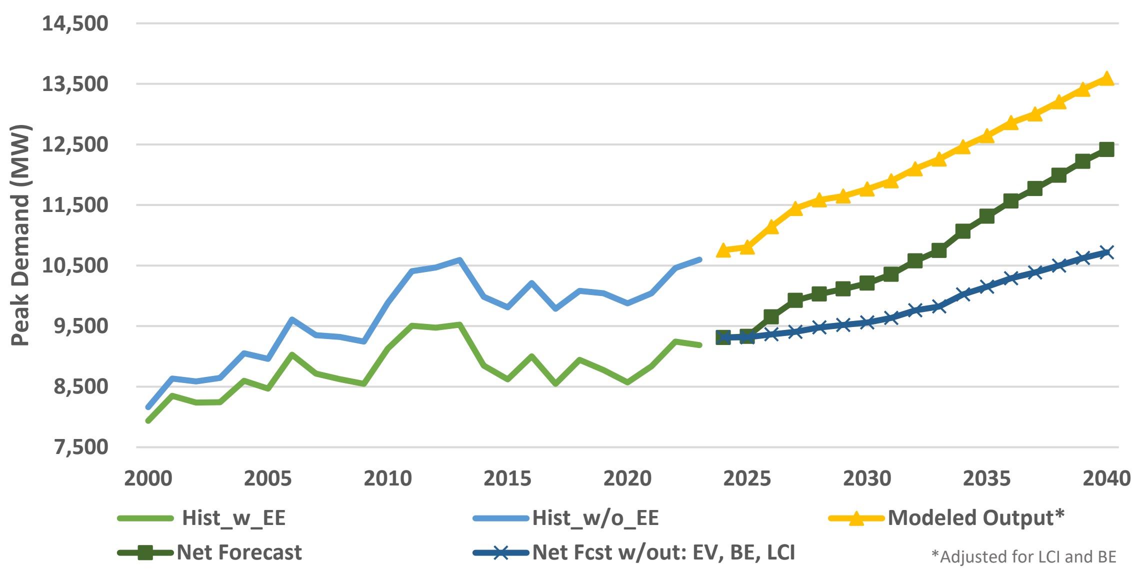
[6] The Coincident Factor calculations were conducted using NSP's old monthly-frequency modeling process, and not the new 8760 process. This was partly due to timing of 8760 process development and partly because the Company could not determine a viable methodology for translating the 8760 process to a MISO CP forecast result.
[7] Produced by the 8760 modeling process.
[8] Docket No. E002/RP-19-368.
[9] Docket No. G002/CIP-23-92.

Figure E-5: Illustration of EE Adjustment – NSP System Demand (MW)



In response to the amendments to the Solar Energy Standard (SES) by the Minnesota Legislature in 2023,[10] an increased emphasis has been placed on distributed solar generation. We developed a forecast of the expected impact on demand and energy based on new programs designed to meet goals established for the SES. We adjusted the Minnesota class-level sales forecasts and the system peak demand forecast to account for the impacts of customer-sited behind-the-meter solar installations on the NSP System. We discuss the distributed solar forecast methodology below.

After determining the base forecast, we developed net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

E. Additional Forecast Adjustments

We made additional adjustments to the energy and demand forecasts to account for expected changes in specific large customers' electricity usage. These additional adjustments include:

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[10] Sec. 16. Minnesota statutes 2022, section 216b.1691. Subd. 2h. Chapter 60 - mn laws (https://www.revisor.mn.gov/laws/2023/0/Session+Law/Chapter/60/).

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand. This adjustment only applies to the Large CI class.
- Increases (or reductions) in usage due to customers moving into and out of our service territory, or planned expansions or reductions of load by existing customers. This adjustment also only applies to the Large CI class, and
- Increasing use of plug-in electric vehicle charging, which we discuss in Section VI.C. below.
- Increasing levels of Beneficial Electrification.
- Increasing adoption of rooftop solar.

F. Forecast Variability

As with any forecast, our projections of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than Global Insight has predicted, electric consumption in the residential sector will be lower. The peak demand for electric power each year is very sensitive to weather conditions and can vary considerably as the result of abnormal weather conditions.

Other forecast uncertainties include potential increases in loads due to new customers and potential losses in loads due to changes in customers' operations. For example, the potential exists for large increases in Data Center loads early in the planning period. However, these loads may fail to materialize as assumed, and NSP may be responsible for serving a different amount of load than forecasted in the Base Case.

Given the uncertainty in any long-term forecast, primarily around the potential for data center loads and their timing, accelerated EV and DG adoption, etc., NSP developed High and Low load sensitivities that adjusted the base outlook using discrete adjustments for these forecast components. This discrete adjustment approach replaces the prior uncertainty modeling method involving Monte Carlo simulations, as a Monte Carlo approach would fail to account for the sizeable increases in load due to data center load or EV adoption. The resulting High and Low load sensitivities are shown below in Figure E-6.

Figure E-6: NSP System Total Net Energy (MWh)
(Includes EE adjustment)

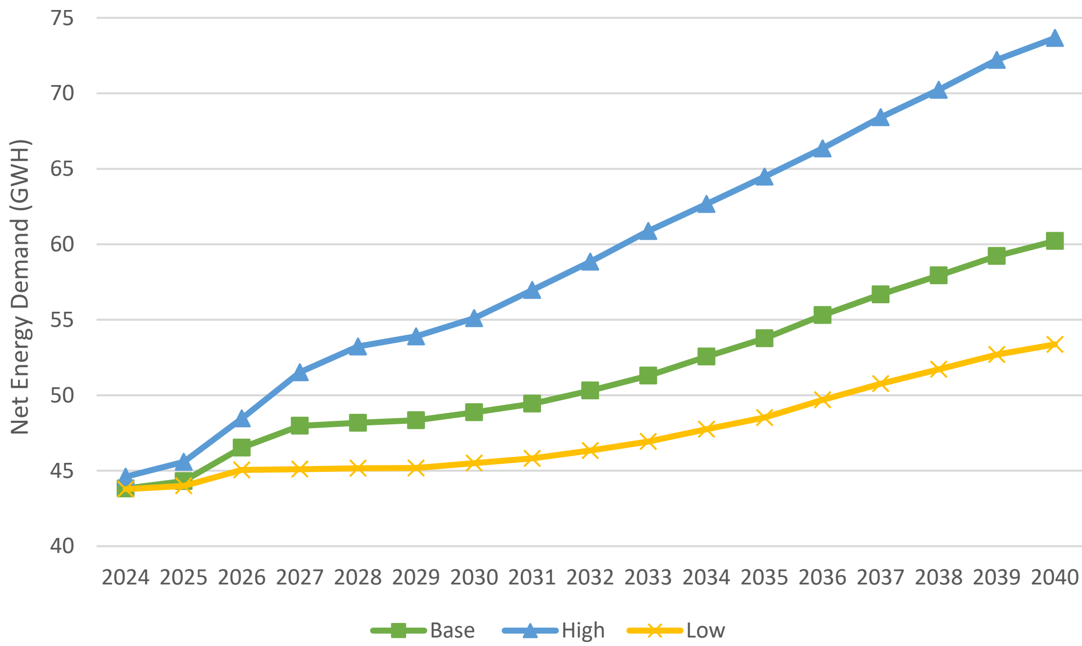
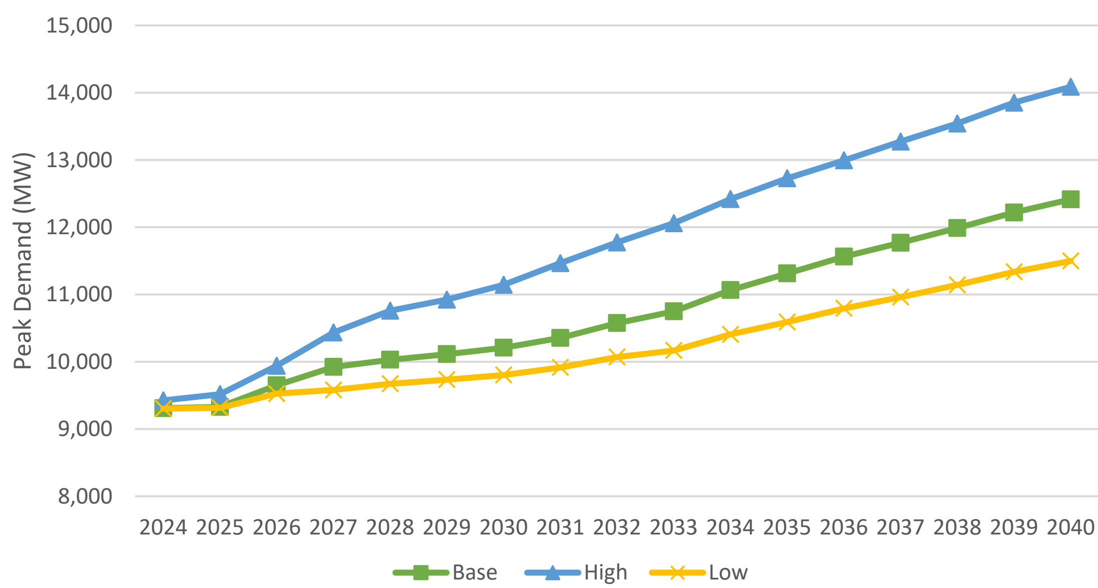


Figure E-7 below shows the high and low sensitivities for base peak demand.[11]

Figure E-7: NSP System Total Base Summer Peak Demand (MW)
(Includes EE Adjustment)



Tables E-1 and E-2 below provide the data underlying Figures E-6 and E-7 respectively.

Table E-1: Annual Net Energy (MWh)
(Including EE Adjustment)

Year	Base	High	Low
2024	43,823	44,602	43,777
2025	44,308	45,588	43,996
2026	46,524	48,460	45,051
2027	47,973	51,524	45,097
2028	48,170	53,232	45,163
2029	48,339	53,898	45,180
2030	48,866	55,102	45,503
2031	49,436	56,970	45,813
2032	50,305	58,844	46,337
2033	51,291	60,876	46,933
2034	52,555	62,663	47,747

Year	Base	High	Low
2035	53,763	64,476	48,517
2036	55,302	66,353	49,694
2037	56,674	68,416	50,764
2038	57,934	70,234	51,718
2039	59,222	72,216	52,695
2040	60,215	73,662	53,370
Average Annual Growth	2.0%	3.2%	1.2%

Table E-2: Annual Base Summer Peak Demand (MW)
(Includes EE Adjustment)

Year	Base	High	Low
2024	9,309	9,425	9,303
2025	9,328	9,517	9,315
2026	9,650	9,940	9,526
2027	9,922	10,434	9,581
2028	10,029	10,759	9,672
2029	10,112	10,923	9,734
2030	10,207	11,144	9,803
2031	10,354	11,466	9,915
2032	10,574	11,773	10,070
2033	10,748	12,058	10,168
2034	11,065	12,417	10,406
2035	11,312	12,726	10,590
2036	11,563	12,994	10,794
2037	11,768	13,273	10,959
2038	11,987	13,542	11,142
2039	12,218	13,851	11,337
2040	12,414	14,087	11,498
Average Annual Growth	1.8%	2.5%	1.3%

G. Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for resources to meet expected customer needs. Thus, these forecasts are an important component in determining the size, type, and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is key to supporting a Resource Plan or resource acquisition.

Per the Commission's Order in the IDP,[12] Xcel Energy made efforts to maintain consistency of DER assumptions between our IDP and IRP by utilizing the same forecast vintages when possible. However, the IDP and IRP processes are fundamentally different, serve disparate functions, and are developed on different time horizons with differing planning cycle durations and cadences. This makes it difficult, if not impossible, to generate forecasts in them that will align perfectly. The IRP is a well-established, long-term resource planning process that indicates size, type, and timing of resource needs over a 15-year time horizon. In comparison, the nascent IDP shows a five-year budget of discrete projects and investments. The five-year budget used for the IDP is built every year on the forecast from the previous fall – for example, the 2023 IDP budget was based on forecast data from Fall 2022. This is significantly different in the IRP, where the modeling happens only three to six months in advance of the filing date every four years, meaning that the most recent and relevant forecast vintages are used.

Despite these differences, we made efforts when developing this IRP to set the forecasts for DER consistently between our IDP and IRP to align with the Commission's IRP Order.[13] Because of the modeling timeline for the IRP, finalization of the IRP models was not complete at the time of IDP submission on November 1, 2023. However, we were able to use some forecasts or updated versions of forecasts developed for the IDP in our IRP process.

Table E-3 below identifies the forecast vintages that were used for the various IDP and IRP forecasts that we provided in Appendix A1: System Planning of our November 1, 2023 IDP.

[12] July 26, 2022, Order, Docket No. 21-694, Ordering Paragraph 4.
[13] The Commission's latest IDP Order includes a parallel Order Point; *see* July 26, 2022 Order in Docket No. E002/M-21-694, at Order Point 4.

Table E-3: Forecast Vintage Comparison

Forecast	Vintage Reflected in Corporate-Level DER Scenario Modeling	Vintage Used in LoadSEER DER Scenario Modeling	Vintage Used in IRP Energy Forecast
Distributed Solar PV	June 2023	June 2023	June 2023
Community Solar Gardens	August 2023	August 2023[14]	August 2023
Distributed Energy Storage	September 2023	2021 IDP	Do not model in IRP
Energy Efficiency	September 2023	Embedded In 2022 Energy Sales & Demand Forecast	September 2023
Demand Response	2022	Embedded In 2022 Energy Sales & Demand Forecast	September 2023
Electric Vehicles	July 2023	2022	July 2023

We assume Distributed Energy storage will cause minimal overall increases in energy consumption since there are only small losses associated with consumer-level storage, which is why it was not modeled for this IRP. Energy storage will likely have a notable impact on peak demand in the distant future once adoption is widespread and a Time of Use (TOU) rate encourages customers to consume from the grid only at specific times. We expect to enhance our forecast with assumptions for consumer-level energy storage in the future, but we do not currently make assumptions for TOU adoption or its estimated impacts on customer usage.

The review process for a Resource Plan or a resource acquisition typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic conditions, business operations, and technology changes occur. The graphs below compare the peak demand and energy of the Company's current forecast with the forecasts filed in the 2019 Resource Plan.

Figures E-8 and E-9 below indicate that the Fall 2023 energy and load forecasts are higher than the Fall 2018 forecast used in our 2019 Resource Plan due, primarily, to the current Resource Plan's assumptions for large new data center loads and a more reasonable forecast for adoption of Electric Vehicles.

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[14] This sensitivity includes a forecast for solar that will meet Distributed Solar Energy Standard (DSES), Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16, and is discussed in section II.C.7.

Figure E-8: Net Energy Requirements (MWh) – Comparison of Current and Previous Base Case Energy Forecasts

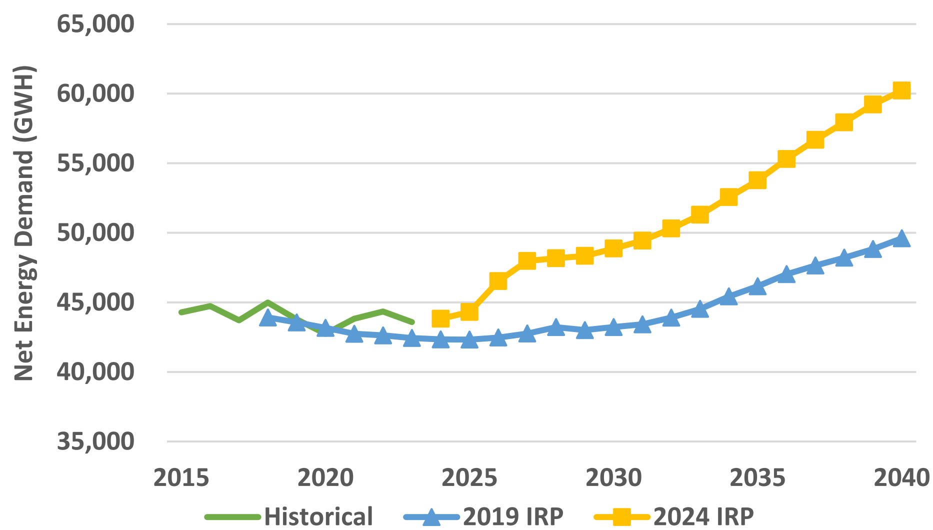
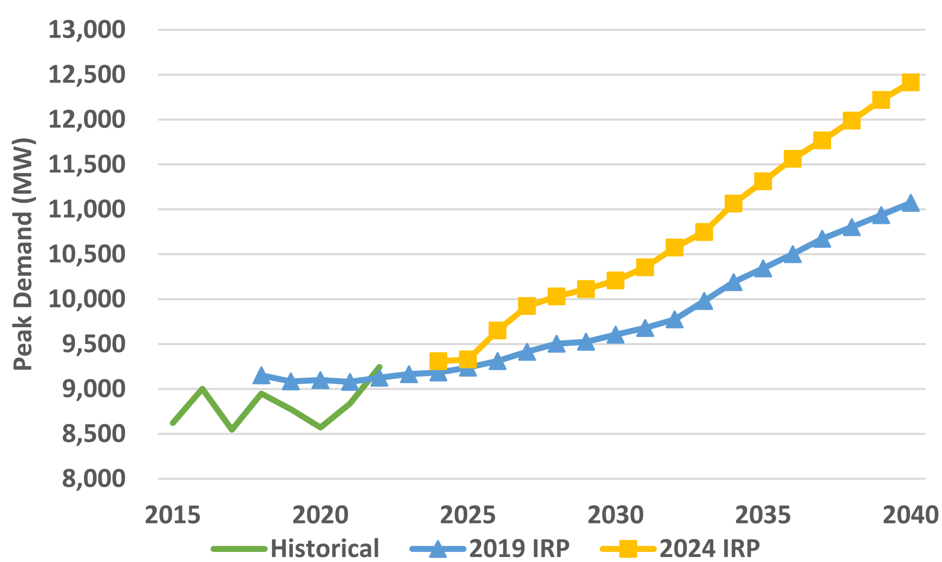


Figure E-9: Peak Demand (MW) – Comparison of Current and Previous Demand Base Case Forecasts



The 2019 Resource Plan assumed EV growth effectively stopped in 2024 at just 235,000 MWh in EV requirements per year; a level we are likely to surpass in the next year or two. EV assumptions in this Resource Plan are detailed in Section VI.C. of this appendix.

Further, projected economic growth is notably higher than forecast in the 2019 Resource Plan. For example, employment in the Minneapolis-St. Paul metropolitan area is expected to gain an average of 0.4 percent per year from 2024-2040, whereas the 2019 Resource Plan's employment outlook only grew at 0.2 percent.[15]

II. OVERALL LOAD FORECAST METHODOLOGICAL FRAMEWORK

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions. Minnesota, North Dakota, and South Dakota are served by Northern States Power Company (NSPM). Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The NSPM and NSPW Systems operate as an integrated system. The forecast is referred to as the 2023v2.0 Forecast (completed in July 2023).

A. Specific Analytical Techniques

1. Econometric Analysis. Xcel Energy used econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors (exceptions to this are noted in bullet 2):
   a. Residential without Space Heating;
   b. Residential with Space Heating;
   c. Small Commercial and Industrial;
   d. Large Commercial and Industrial (NSPM only);
   e. Public Street and Highway Lighting (Minnesota only);
   f. Sales to Public Authorities (Minnesota only).

   Xcel Energy also used econometric analysis and the 8760 process to develop the total system MW peak demand forecast.
2. Trend analysis or simple historical averages were used for all other sectors, which includes Large Commercial and Industrial (in NSPW jurisdictions),

[15] IHS Global Insight, July 2018 vintage, 2020-2034 planning period.

Public Street and Highway Lighting, Other Sales to Public Authorities for all jurisdictions except Minnesota, and Interdepartmental sales for all jurisdictions.

3. Loss Factor Methodology. Loss factors by jurisdiction were used to convert the sales forecasts into system energy requirements (at the generator).
4. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy used quantitative models to structure its judgment in the forecasting process.

The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts were summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy created the native energy requirements based on the sales forecasts. A system loss factor for each jurisdiction, developed based on modeled historical losses, is applied to the sales forecast to calculate total losses. The sum of the MWh sales and the MWh losses equals the native energy requirements. The native energy requirements, along with peak producing weather and binary variables, then were used as independent variables within an econometric model to forecast MW peak demand for the Xcel Energy North System.

B. Models Used

1. ***Residential Econometric Models.*** Sales to Residential customers represent 31.5 percent of NSP System electric sales in 2022. Residential sales are divided into two sub-classes for each NSPM jurisdiction: space heating and without space heating. NSPW jurisdictions only have a total Residential customer class. Regression models using historical data are developed for each Residential sector. A variety of independent variables were used in the models, including:

    - Real Personal Income or Real Personal Income per Capita for the respective jurisdiction;
    - Average price (reported revenues/reported sales) for the respective jurisdiction;
    - Gross Metro Product for the respective jurisdiction;
    - Total population for the respective jurisdiction;

- Average price of West Texas Intermediate crude oil;
- Actual heating (HDD) and temperature humidity index (THI) degree days;
- Number of customers;
- Number of monthly billing days;
- Month specific binary variables;
- Other binary and or trend variables.

2. ***Small Commercial and Industrial Econometric Models.*** The small commercial and industrial sector represents 42.75 percent of NSP System electric sales in 2022. The models are econometric regressions using historical data. The models include a combination of variables, including the following:

   - Number of small commercial and industrial customers;
   - Gross State/Metro Product for respective jurisdiction;
   - Employment for respective jurisdiction;
   - Actual heating (HDD) and temperature humidity index (THI) degree days;
   - Number of monthly billing days;
   - Month specific binary variables;
   - Other binary and or trend variables.

3. ***Large Commercial and Industrial Econometric Model (NSPM).*** Sales to the large commercial and industrial sector represent 25.2 percent of NSP System electric sales in 2022. The regression models used for NSPM jurisdiction LCI forecasts use historical data and the following explanatory variables:
   - Industrial Manufacturing Employment;
   - Number of monthly billing days;
   - Month specific binary variables;
   - Other binary variables.

4. ***Others.*** Sales to the "Others" sector represent 0.6 percent of NSP System electric sales in 2022. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Regression models are used to estimate sales for the PSHL and

OSPA classes (Minnesota only), using historical data and a combination of variables, including the following:

a. Population for the respective jurisdiction;
b. Gross Metro Product for the respective jurisdiction;
c. Number of monthly billing days;
d. Month specific binary variables;
e. Other binary and or trend variables.

5. ***Municipals.*** As of 2014 there are no longer any municipal customers for whom NSP or NSPW provides firm service.

6. ***Peak Demand. The peak demand forecast i***s the result of an updated, granular process referred to as the "8760" peak forecasting process. Section D "Forecast Methodology" summarizes this process.

C. Key Demand and Energy Forecast Variables

Below we discuss some of the key variables that are included in the 2024 Resource Plan forecasts.

1. Demographics

Demographic projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with demographic statistics. The number of residential customers, weather data, and economic indicators are key variables in the residential energy sales forecast. Over 99 percent of the variability in historical electric residential customer counts in our service territory can be explained through an econometric model that contains either population or households as key drivers. The forecasts for population and households are provided by Global Insight. We forecast an average annual growth rate for total residential customers on our system of 0.7 percent, with the addition of 12,153 residential customers on average per year from 2024 through 2040.

2. Economic Indicators

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. These variables include gross state product, employment, and real personal income. The variables used are specific to the jurisdiction and are statistically significant in the sales models for the residential and commercial and industrial customer classes. Growth in electric energy consumption in the residential and commercial and industrial sectors closely follows trends in economic activity. Global Insight provided the economic forecasts used in our regression models.

For the planning period, the economy is expected to continue to grow, resulting in growth in electric energy consumption.

3. Weather

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index (THI). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature.

We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

III. FORECAST ADJUSTMENTS

The outputs of raw econometric modeling are adjusted to account for either: 1) components that cannot be modeled correctly using regression, such as the addition of a new customer in the forecast timeframe, or 2) components that are necessary because of our regression modeling process, such as "adding back" the effects of energy efficiency.

A. Energy Efficiency Programs

The sales outlooks for residential and commercial/industrial classes are initially modeled based on a history that excludes the effects of Energy Efficiency (EE), and the resulting forecasts also exclude the effects of EE. This approach is necessary to properly account for EE in the forecast timeframe as the gross outlook (the outlook excluding EE) can then be adjusted per any assumption of future EE.

The first step in this process involves collecting EE data for the historical period being modeled. In the Fall 2023 models, NSP collected monthly energy savings for any measure impacting customer usage for the time-period from 2008 to 2023. Since EE measures have a "life of measure" that is typically longer than just one year, EE data for several years prior to the Fall 2023 estimation timeframe (2008-2023) was collected.

A hypothetical "gross of EE impacts"[16] sales data set is created by subtracting historical EE impacts from historical sales. That "gross of EE impacts" series is then modeled and forecast using regression analysis. The resulting sales series is presumed to also be "gross of EE impacts," and must be adjusted per any future impacts of EE. Future EE impacts resulting from past measures are netted from the energy outlook, whereas EE resulting from future measures is modeled as a resource in Encompass.

B. Behind-the-Meter Distributed Solar Generation

In response to changes to the SES by the Minnesota Legislature, as discussed above, an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. The process of incorporating behind-the-meter distributed solar generation into the forecast process is similar to how EE program savings are incorporated in the sales and peak demand forecasts. Historical behind-the-meter distributed solar generation is added-back to the historical sales and peak demand modeling data to create a "gross of historical distributed solar" sales series, which is then modeled. The resulting forecast output is presumed to be gross of distributed solar and must be reduced for the future impacts of behind-the-meter installations on the class level sales in Minnesota and South Dakota and the NSP System peak demand.

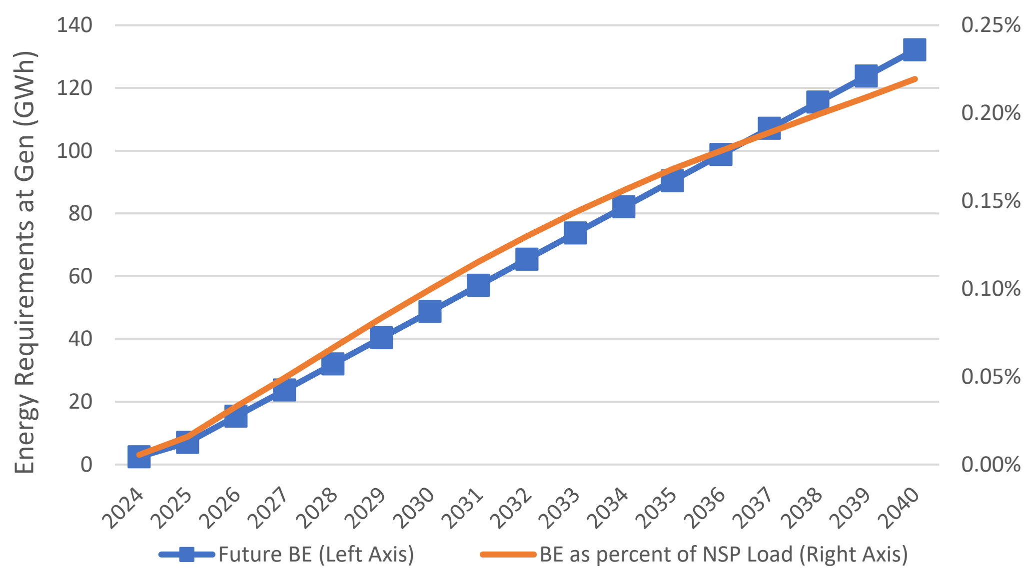
C. Beneficial Electrification

We made assumptions for Beneficial Electrification (BE) of space and water heating based on achievement of the annual goals filed in the Xcel Energy 2024-2026 Energy Conservation and Optimization Triennial Plan (Docket No. G, E002/CIP-23-92) for 2024-2026, and assumed achievement of the 2026 goal for all subsequent years. The goal assumptions included in this Plan are modest as the electrification technologies

[16] Would not include any naturally occurring/customer driven EE. The adjusted series only accounts for Company EE resulting from Conservation Improvement Programs (CIP).

and programs are just being introduced to the market and have significant barriers to adoption the next few years. This is the first time NSP has included BE assumptions in our electricity sales forecast,[17] and the Company will likely continue to keep its assumptions modest until observed trends or policy suggest higher levels of BE. The chart below shows the Company's assumption for BE in both GWh requirements and as a percent of overall NSP load.

Figure E-10 Base Case Beneficial Electrification Assumption



D. Large C&I Adjustments

Adjustments have been made to the forecast to account for planned changes in production levels for several large customers in Minnesota and Wisconsin. The most significant Large C&I adjustments concern the anticipated and expected addition of several large data centers in Minnesota. The assumptions for LCI adjustments under the Base, High, and Low sensitivities are discussed in section VI.F. of this Appendix.

[17] Displacement of natural gas consumption by this electrification was also reflected in NSP's forecast of gas sales forecast.

IV. METHODOLOGY

The strength of the process Xcel Energy used for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes, which is why we developed high and low load sensitivities.

V. DATA SOURCES

MWh sales and MW peak demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales and MW peak demand. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

Weather data. Weather data (dry bulb temperature and dew points) were collected from www.weatherunderground.com and the National Oceanic and Atmospheric Administration for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically, they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

A. Input Data Adjustments and Assumptions

Weather Adjustments. Xcel Energy adjusts the monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds proportionately with the billing month schedule.

Economic Adjustments. All economic series are deflated to 2012 constant dollars.

B. Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

- *Demographic Assumption.* Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

- *Weather Assumption.* Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 2003-2022. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

- *Loss Factor Assumptions.* The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses modeled historical losses for each jurisdiction for the first forecast calendar year, and assumes it will not change in the future.

C. MISO Coincident Peak Demand Forecast

The MISO coincident peak (CP) forecast is an estimate of NSP load at the time of MISO peak. The process involves scaling our overall NSP system peak, i.e. our non-coincident peak (NCP), by a coincidence factor (CF). The coincident factor is calculated using the methodology described below.

Historical monthly MISO-coincident peaks are queried using the historical peak date/times provided by MISO.[18] Peak-day weather conditions are also queried using these date/times. MISO coincident peaks and corresponding CF for the Planning Year 2024-2025 (PY 24-25) are modeled as a function of historical NSP NCP, weather, and monthly binaries. The peak-day weather forecast assumption is a simple monthly historical average of 2009-2023 CP weather data.

The resulting CF for the Planning Year 2024-2025 (PY 24-25) are averaged with last year's CF's (PY 23-24) to produce the seasonal peak coincident factors used in this Resource Plan. These factors are shown in Table E-4 below.

Table E-4: Coincident Factor Assumptions

	Summer	Fall	Winter	Spring
Average Coincident Factor (PY23-24 & PY24-25)	92.24%	92.67%	97.09%	95.61%

D. Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to MISO, who then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

VI. SENSITIVITY ASSUMPTIONS

The Company's Fall 2023 load forecast is used as the base assumption in this Resource Plan. The forecast assumes adoption of electric vehicle (EV), new Large C&I customer additions, Beneficial Electrification (BE), and demographic/economic growth. Two alternative sensitivities were developed to model the range of potential outcomes for NSP energy requirements and load: the High and Low load sensitivities. The details of each sensitivity, by component assumptions are described in this section. Table E-5 below shows how component assumptions were adjusted from the base case by sensitivity. Base load (i.e. the modeled econometric outputs) were not adjusted in any of the sensitivities; instead, discrete adjustments for each component were developed to clearly define each sensitivity. This approach replaces the previous process involving Monte Carlo simulation.

Table E-5: High and Low Load Sensitivity Assumptions

Component	High Load Case	Low Load Case
Base Load	Base Case	Base Case
Solar	Base Case	High Solar
Demand-Side Management	Base Case	Base Case
Beneficial Electrification	High BE	No BE
Electric Vehicles	Full Achievement	Low Achievement
Large Commercial & Industrial Customers	High LCI	Low LCI

A. Distributed Solar

We offer several programs to customers interested in solar as a renewable energy opportunity, including our Solar*Rewards program and our Community solar program, which provides the opportunity to earn bill credits for Community Solar Gardens (CSGs). In addition, for larger systems, we offer a net-metering option. We have factored all these distributed solar PV options into our various distributed solar forecasts. As we will discuss further below, the rooftop solar forecast is from June 2023 and the CSG forecast is from August 2023.

In determining our Solar*Rewards forecast, we updated our goals to be consistent with legislative outcomes that increased and provided funding for Solar*Rewards incentives for 2023 to 2025. The Solar*Rewards installations for 2023 to 2026 were estimated based on historical trends of funding levels and project conversion rates.

For net metering and CSGs, we assume that customers who participate in solar programs would consider, in most cases, that these programs are substitutes for each other. Therefore, the incremental growth in one category is interchangeable with another category.

We used the average of a Bass Diffusion and an economic model to derive the base forecast of net metered solar. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Economic models use a simple payback to estimate potential adoption. The Bass Diffusion model is calibrated using state specific, historical solar installed capacity through December 2022. Additionally, we have incorporated into both the Bass diffusion and economic models, a factor for the percentage of customers unable to install solar on their roof, for various reasons (e.g., renters, shaded roof, inability to access the roof, etc.). The main variables impacting adoption in the economic payback model are installation and maintenance cost, hosting capacity, inverter replacement, investment tax credit, utility rates, and capacity factors. Models and estimates are updated as new data becomes available and estimates can vary significantly.

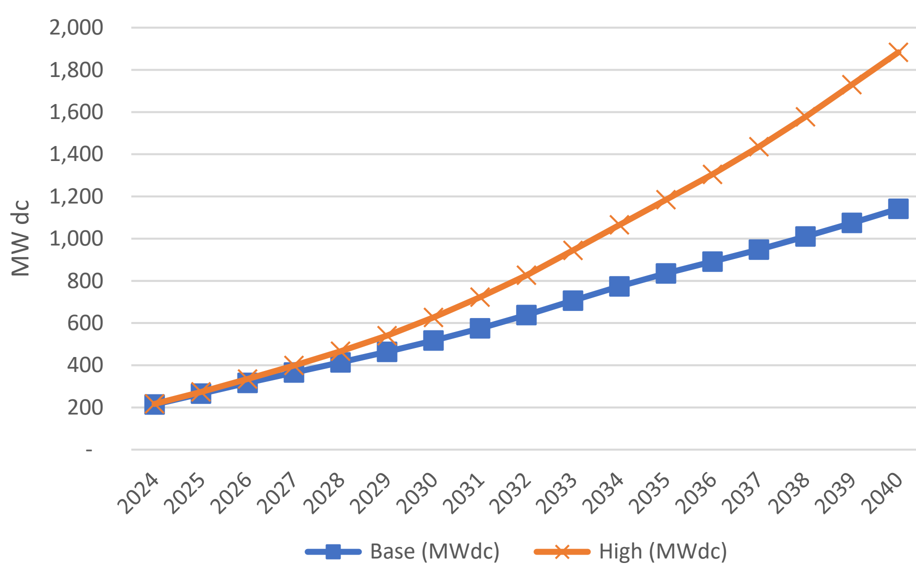
We created the High solar adoption sensitivity using a combination of lower installation cost and higher savings. The High sensitivity assumes the installation costs decrease at a faster rate than the Base outlook. The Bass Diffusion High sensitivity uses higher coefficients compared to the Base case. These coefficients were calibrated using a section of the historical curve that showed higher than average growth.

The Base and high load sensitivities use the base PV adoption scenario, the results of which indicate around 706 MWdc for the total installed rooftop distributed solar by 2033. The low load sensitivity assumes a high PV adoption outlook, the results of which show installed rooftop distributed solar around 944 MWdc by 2033. We provide a tabular and graphical view of the forecast in Table E-6 and Figure E-11.

Table E-6: Distributed Rooftop Solar Scenarios

	Base (MWdc)	High (MWdc)
2024	214	217
2025	265	274
2026	317	335
2027	365	399
2028	413	466
2029	463	540
2030	517	626
2031	575	723
2032	638	827
2033	706	944
2034	774	1,065
2035	835	1,184
2036	891	1,304
2037	948	1,436
2038	1,010	1,577
2039	1,074	1,730
2040	1,142	1,883

Figure E-11: Distributed Rooftop Solar Forecast



B. Distributed Wind

We presently have a small number of distributed wind projects on our system, with a total of 93 projects that comprise 12 MWdc. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption, compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we are not providing a forecast in conjunction with this Resource Plan.

C. Electric Vehicles

With an increase of available models, EV adoption has increased, and there are approximately 38,000 light-duty EVs estimated to be in Xcel Energy's Minnesota service territory as of September 2023. The EV forecasts discussed below were updated in July 2023.

Light Duty Vehicles

We currently estimate light-duty EV adoption for the Base and Low forecast using two modeling techniques: (1) Bass Technology Diffusion, and (2) Economic models.

Our current approach for the Base forecast relies on state and Xcel Energy service area specific data. The Bass Diffusion model is calibrated using state specific historical EV sales. The economic model calculates the total cost of ownership for EV compared to traditional internal combustion engine (ICE) automobiles. An average of both the Bass Diffusion and total cost ownership models are used to estimate EV adoption. Additionally, we have incorporated into both the Bass Diffusion and economic models a factor for the percentage of vehicles in urban and rural areas. Presently, higher adoption is occurring in urban areas with the rural areas anticipated to ramp-up slowly. Our cumulative Base adoption estimate for 2030 is approximately 7.8 percent of all registered cars and light trucks in our Minnesota service territory.

We create the Low economic model sensitivity for Minnesota and the Dakotas using a combination of battery prices and gasoline prices. The Low sensitivity assumes battery prices are 20 percent higher than the Base Case outlook, and gasoline prices lower by one standard deviation. The Low sensitivities for the Bass Diffusion models are created using data from states that reflect low historical adoption rates.

The High sensitivity reflects the Minnesota state goal of EV's accounting for 20 percent of all light-duty vehicles by 2030 and also applies this goal to medium and heavy-duty vehicles as well. This results in 100 percent EV saturation by 2052. This same methodology is then applied to produce the estimates for North Dakota and South Dakota. The High sensitivity outlooks for Wisconsin and Michigan were developed by scaling the Base outlooks using the South Dakota's ratio of High to Base outlook[19].

We note that EV fuel efficiency could be impacted by advances in technology; we currently assume gasoline cars average 25 miles per gallon. Analysis indicates that battery costs are a significant factor for higher EV prices. The main variables impacting adoption are available tax incentives, price differential between EV and ICE vehicles, and gasoline prices. Models and estimates are updated annually with new relevant available data and estimates can vary significantly. Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust with additional data available every year.

Our estimates show significant volatility between various sensitivities. The estimates are also sensitive to several externalities like policy changes (e.g., incentive changes, cybersecurity requirements, carbon requirements); technology changes (e.g., improvements in existing battery technologies and new disruptive battery or electric motor management technologies, autonomous vehicles, alternate technologies like fuel cell vehicles); geopolitical factors – such as trade and tariff issues; availability of raw materials such as lithium, cobalt, and nickel; and infrastructure availability.

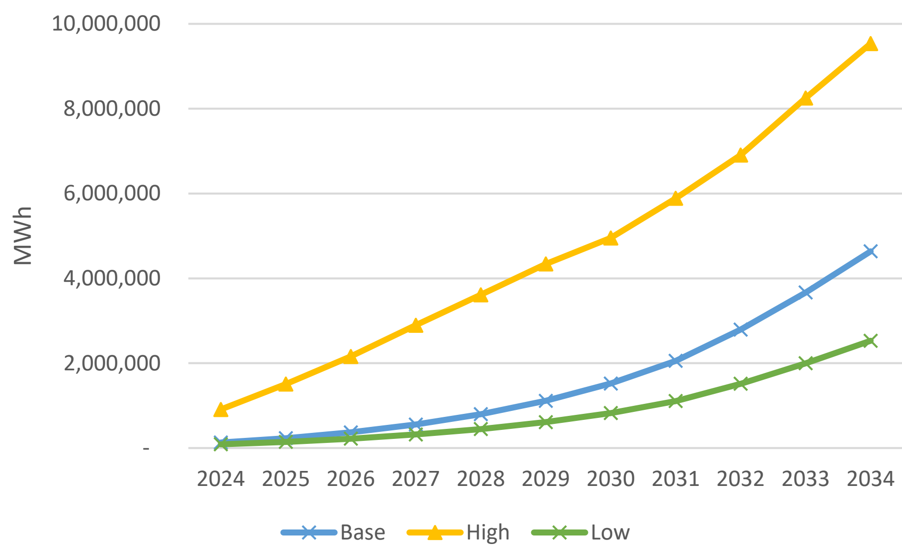
Additionally, many of the inputs change frequently and could produce significant swings in the model outputs.

Medium and Heavy-Duty Vehicles

We utilize estimates from a third-party consultant for medium and heavy-duty electric vehicle Base Case adoption in Xcel Energy's service territory.

[19] The same method was used to develop Wisconsin and Michigan's low sensitivity outlooks.

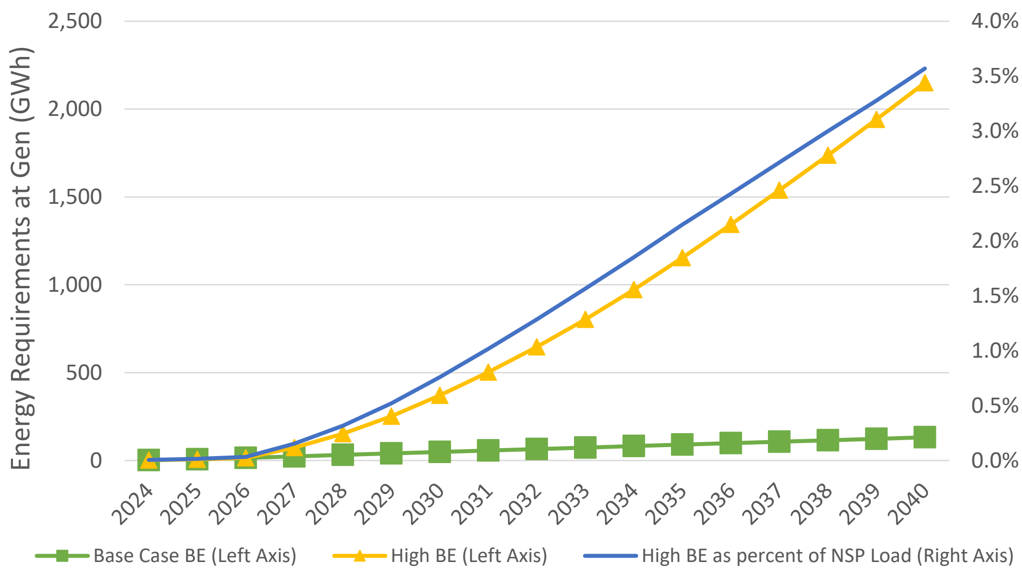
Figure E-12: NSP System Base, High, and Low EV Sensitivities



D. Beneficial Electrification

Assumptions for Beneficial Electrification (BE) were adjusted in both the High and Low sensitivities. The Low sensitivity simply assumed no added load from beneficial electrification, and the High sensitivity assumed substantial growth in BE over the Base Case assumptions. Under the High load sensitivity, new load from BE would comprise about 3.5 percent of total energy requirements.

Figure E-13: NSP System Base and High Beneficial Electrification Forecasts



E. LCI Assumptions

The NSP Base, High, and Low outlooks include some load for several prospective new large data center customers in the Minnesota jurisdiction, and the volume of load included in each sensitivity for these customers is dependent on the likelihood of each load tranche.

Under the Base sensitivity, we assume **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of new load from data centers in the 2025-2026 timeframe. A location in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** is especially promising location, and we expect that any of the above-mentioned companies would take advantage of the opportunity to locate there, but at this time it is unclear which project is most likely. We also assumed several smaller additions or expansions by new or existing customers that would add load in the 2023-2024 timeframe, but these are more than offset by expected new on-site generation by existing customers; the combined impact of non-data center load adjustments in the Base forecast is -4 MW.

Under the High sensitivity, we assume data centers add **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** due to expansions in the

2030-2033 timeframe. These expansions are added to the Base case assumptions bringing the total new data center load to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** under the High sensitivity. This sensitivity also includes a **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** expansion by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** However, this assumed expansion is not expected until **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

Under the Low sensitivity, we assume **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of new data center load growth**.** The timing of these load additions is the same as in the Base case (2025-2026), but the magnitude is more conservative.

APPENDIX F – ENCOMPASS MODELING ASSUMPTIONS AND INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and determining the present value of modeled costs is 6.39 percent. The rates shown below were calculated by taking a weighted average of the most recent electric retail rate case in each NSP jurisdiction.

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.83%	4.34%	2.03%	1.47%
Common Equity	52.48%	9.35%	4.91%	4.91%
Short-Term Debt	0.68%	3.18%	0.02%	0.02%
Total			**6.96%**	**6.39%**

B. Inflation Rate

The inflation rate is applied to existing resources, generic resources, and other costs associated with general inflationary trends in the modeling. For long term capacity expansion planning purposes, we used the two percent long-term inflation rate inflation target established by the Federal Reserve.

C. Reserve Margin

The modeled Planning Reserve Margin is based on the MISO Planning Year 2024-2025 assumptions, adjusted for the average coincidence factors in MISO Planning Year 2024-2025 and Planning Year 2023-2024.

Table F-1: Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY24/25	9.00%	14.20%	27.40%	26.70%
Average Coincidence Factor	92.24%	92.67%	97.09%	95.61%

The higher Planning Reserve Margin or MISO Reliability Based Demand

Curve[1](RBDC) Opt-Out sensitivity represents the additional capacity necessary to opt out of the RBDC and assumes the effective reserve margin as shown in Table F-2.

Table F-2: Reliability-Based Demand Curve Sensitivity

	Summer	Fall	Winter	Spring
Reliability-Based Demand Curve Opt Out[2]	3.1%	3.4%	2.7%	1.7%

D. Greenhouse Gas Costs

The December 19, 2023 Commission Order in Docket Nos. E999/CI-07-1199, E999/DI-22-236, E-999/CI-14-643 Addressing Environmental and Regulatory Costs (Environmental and Regulatory Costs Order)[3] at Order Point 2 requires utilities to continue to analyze potential resources under a range of assumptions about environmental values and future regulatory costs, including five modeling scenarios as outlined in *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06,* Docket No. E-999/CI-07-1199, Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs (September 30, 2020), Ordering Paragraph 2, as modified.

Per the Environmental and Regulatory Costs Order, for purposes of measuring environmental and socioeconomic costs under Minn. Stat. § 216B.2422, Subd. 3, the PVSC Base Case Greenhouse Gas (GHG) values, inclusive of carbon dioxide, methane and nitrous oxide, are based on the United States Environmental Protection Agency's (EPA) September 2022 *External Review Draft of Report on the Social Cost of Greenhouse Gases*[4] (EPA SC-GHG), mid EPA SC-GHG values, with the high and low EPA SC-GHG values as sensitivities. The EPA SC-GHG costs are applied post processing and do not impact dispatch order. All prices are converted from metric ton to short ton and to nominal dollars using two percent escalation factor.

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[1] The RBDC proposal, currently under consideration by FERC, is a proposed design for MISO's Planning Resource Auction that aims to reflect the reliability value of capacity and produce more efficient and stable capacity prices. Pending FERC approval, the RBDC reform is expected to be implemented in PY 2025-2026.

[2] Reliability Requirement Representations in the Planning Resource Auction: Consideration of a Reliability-Based Demand Curve (August 22, 2023). Available at: https://cdn.misoenergy.org/20230822-23%20RASC%20Item%2006a%20Reliability%20Based%20Demand%20Curves%20Presentation%20(RASC-2019-8)629946.pdf

[3] Order in Docket Nos. E-999CI-07-1199, E-999/DI-22-236, E-999/CI-14-463. December 19, 2023.

[4] We understand the EPA finalized the draft SC-GHG values in November 2023.

Starting in 2028, the PVSC Base Case values also include the Regulatory Cost of Carbon (RCC), relying on the "mid" end of the range of regulated costs.[5,6] Although the cost range was amended in 2023, when the Commission modified the range to between $5 and $75, these values will still begin being applied in 2028, and still under the range of assumptions about environmental values and future regulatory costs (including the five modeling scenarios) outlined in the September 30, 2020 Order.[7] The low end and high end of the range are modeled in separate sensitivities. The regulatory costs are applied to all carbon emitting units as well as market energy purchases, hence affect dispatch order.

The following additional sensitivities have also been modeled: high RCC with high draft EPA SC-GHG, low RCC with low draft EPA SC-GHG costs, zero RCC with low, mid and high draft EPA SC-GHG. We have adjusted the EPA SC-GHG values for modeling purposes by subtracting the regulatory cost of carbon from the EPA SC-GHG value beginning in 2028 to avoid double counting of GHG costs. All prices escalate at general two percent inflation.

The values modeled in the PVSC Base Case and alternative scenarios are identified below in Table F-3 and F-4.

[5] Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E-999/DI-17-53. June 11, 2018.
[6] Order in Docket Nos. E-999CI-07-1199, E-999/DI-22-236, E-999/CI-14-463. December 19, 2023.
[7] In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06, Docket No. E-999/CI-07-1199. Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs. September 30, 2020.

Table F-3: CO2 Regulatory Costs

CO2 Regulatory Costs ($nominal per short ton)			
Year	Low Regulatory Cost	Mid Regulatory Cost	High Regulatory Cost
2024	$0.00	$0.00	$0.00
2025	$0.00	$0.00	$0.00
2026	$0.00	$0.00	$0.00
2027	$0.00	$0.00	$0.00
2028	$5.00	$40.00	$75.00
2029	$5.00	$40.00	$75.00
2030	$5.00	$40.00	$75.00
2031	$5.00	$40.00	$75.00
2032	$5.00	$40.00	$75.00
2033	$5.00	$40.00	$75.00
2034	$5.00	$40.00	$75.00
2035	$5.00	$40.00	$75.00
2036	$5.00	$40.00	$75.00
2037	$5.00	$40.00	$75.00
2038	$5.00	$40.00	$75.00
2039	$5.00	$40.00	$75.00
2040	$5.00	$40.00	$75.00
2041	$5.00	$40.00	$75.00
2042	$5.00	$40.00	$75.00
2043	$5.00	$40.00	$75.00
2044	$5.00	$40.00	$75.00
2045	$5.00	$40.00	$75.00
2046	$5.00	$40.00	$75.00
2047	$5.00	$40.00	$75.00
2048	$5.00	$40.00	$75.00
2049	$5.00	$40.00	$75.00
2050	$5.00	$40.00	$75.00
2051	$5.00	$40.00	$75.00
2052	$5.00	$40.00	$75.00
2053	$5.00	$40.00	$75.00
2054	$5.00	$40.00	$75.00
2055	$5.00	$40.00	$75.00

Table F-4: EPA GHG Social Costs

	CO_2 ($nominal per short ton)			CH_4 ($nominal per short ton)			N_2O ($nominal per short ton)		
Year	Low EPA Social Cost	Mid EPA Social Cost	High EPA Social Cost	Low EPA Social Cost	Mid EPA Social Cost	High EPA Social Cost	Low EPA Social Cost	Mid EPA Social Cost	High EPA Social Cost
2024	$126	$204	$350	$1,497	$1,915	$2,602	$38,320	$57,976	$91,937
2025	$130	$212	$361	$1,593	$2,028	$2,741	$40,036	$60,364	$95,363
2026	$136	$220	$373	$1,693	$2,146	$2,884	$41,805	$62,823	$98,891
2027	$142	$228	$386	$1,797	$2,268	$3,032	$43,629	$65,357	$102,520
2028	$148	$237	$399	$1,904	$2,394	$3,184	$45,510	$67,967	$106,255
2029	$153	$245	$412	$2,013	$2,523	$3,342	$47,448	$70,654	$110,100
2030	$159	$254	$425	$2,128	$2,657	$3,504	$49,445	$73,423	$114,055
2031	$166	$264	$439	$2,258	$2,809	$3,688	$51,540	$76,302	$118,129
2032	$173	$273	$453	$2,393	$2,966	$3,878	$53,700	$79,266	$122,320
2033	$180	$283	$467	$2,531	$3,129	$4,073	$55,925	$82,318	$126,632
2034	$186	$293	$482	$2,675	$3,297	$4,276	$58,218	$85,460	$131,067
2035	$193	$303	$498	$2,824	$3,470	$4,485	$60,580	$88,695	$135,630
2036	$201	$314	$513	$2,978	$3,648	$4,700	$63,013	$92,025	$140,321
2037	$208	$325	$530	$3,135	$3,832	$4,922	$65,518	$95,454	$145,147
2038	$216	$336	$547	$3,299	$4,023	$5,150	$68,100	$98,983	$150,109
2039	$225	$348	$563	$3,468	$4,220	$5,387	$70,758	$102,614	$155,212
2040	$233	$360	$581	$3,642	$4,422	$5,631	$73,496	$106,352	$160,459
2041	$242	$373	$599	$3,831	$4,641	$5,892	$76,494	$110,417	$166,111
2042	$251	$386	$618	$4,027	$4,868	$6,163	$79,583	$114,603	$171,926
2043	$260	$399	$638	$4,227	$5,101	$6,440	$82,764	$118,912	$177,905
2044	$271	$413	$658	$4,436	$5,342	$6,727	$86,040	$123,349	$184,056
2045	$281	$427	$679	$4,650	$5,590	$7,022	$89,416	$127,915	$190,382
2046	$291	$442	$701	$4,872	$5,846	$7,328	$92,891	$132,614	$196,887
2047	$302	$458	$723	$5,099	$6,110	$7,642	$96,471	$137,449	$203,575
2048	$314	$474	$745	$5,335	$6,382	$7,965	$100,155	$142,427	$210,453
2049	$325	$490	$768	$5,577	$6,663	$8,298	$103,948	$147,547	$217,525
2050	$337	$506	$792	$5,829	$6,953	$8,643	$107,854	$152,815	$224,794
2051	$349	$523	$816	$5,945	$7,092	$8,816	$111,751	$158,089	$232,106
2052	$361	$539	$839	$6,196	$7,386	$9,169	$115,762	$163,512	$239,618
2053	$373	$556	$865	$6,454	$7,689	$9,532	$119,888	$169,090	$247,340
2054	$386	$575	$889	$6,722	$7,999	$9,906	$124,134	$174,825	$255,273
2055	$399	$591	$916	$6,996	$8,320	$10,291	$128,499	$180,723	$263,425
EPA Discount Rate	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the four locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The mid-point externality costs are the average of the low and high values. All prices are escalated to 2023 real dollars using the 2022 GDP IPD. These costs are applied post processing and do not impact dispatch order.

Table F-5: Externality Costs

MPUC Low Externality Costs 2023 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,976	$5,509	$4,156	$0
NOx	$3,347	$2,991	$2,407	$32
PM2.5	$12,202	$7,821	$4,168	$994
CO	$1.88	$1.34	$0.36	$0.36
Pb	$5,540	$2,923	$711	$711

MPUC High Externality Costs 2023 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$17,439	$13,723	$10,128	$0
NOx	$9,571	$8,896	$7,724	$180
PM2.5	$30,481	$19,496	$10,235	$1,513
CO	$4.00	$2.37	$0.72	$0.72
Pb	$6,856	$3,530	$793	$793

MPUC Midpoint Externality Costs 2023 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$12,208	$9,616	$7,142	$0
NOx	$6,459	$5,943	$5,066	$106
PM2.5	$21,341	$13,659	$7,202	$1,254
CO	$2.94	$1.85	$0.54	$0.54
Pb	$6,198	$3,226	$752	$752

F. Energy Efficiency (EE) Bundles

The Company based our EE bundles on our proposed 2024-2026 ECO Triennial Plan.[8] Three bundles of EE were developed: (1) a low-achievement bundle based on minimum statutory requirements in Minn. Stat. § 216B.241, (2) a mid-achievement bundle based on estimated savings derived from our 2024-2026 ECO Triennial, and (3) a high-achievement bundle based on the "Optimized Bundle" as part of the 2020-

[8] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.

2034 IRP which took into account the most recent state potential analysis.[9] Internal experts provided estimated costs, and energy and demand avoidance characteristics for the programs. Multiple sources were considered for the different bundles including the 2018 *Minnesota Energy Efficiency Potential Study* findings, the Company's ECO Triennial Plan, and IRA policies and funding. In addition to the bundles, naturally occurring EE is embedded in the load forecast.

Each bundle is modeled in Encompass in the same manner as a supply side resource. The first two bundles are forced into the model and are not selectable as they represent our planned program achievement for EE. The High Achievement Bundle (Bundle 3) was offered as a selectable resource by the EnCompass model as part of the optimization process. Bundle 3 was developed by the Company, drawing on the Optimal Bundle in the 2019 IRP.

[9] Upper Midwest Integrated Resource Plan 2020-2034, Xcel Energy, Docket No. E002/RP-19-368, 2019.

Table F-6: Energy Efficiency Bundles

	Energy (GWh)			Demand (MW)			Cost ($000)		
Year	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High
2024	477	138	159	91	26	30	$ 86,040	$ 47,971	$ 79,937
2025	887	256	310	169	49	59	$ 86,202	$ 54,143	$ 81,246
2026	1,298	400	460	247	76	88	$ 82,934	$ 62,811	$ 79,928
2027	1,691	531	654	322	101	124	$ 82,108	$ 57,926	$ 108,775
2028	2,075	659	864	395	125	164	$ 82,108	$ 57,926	$ 123,859
2029	2,455	785	1,023	467	149	195	$ 82,108	$ 57,926	$ 97,752
2030	2,832	835	1,268	539	159	241	$ 92,536	$ 31,685	$ 152,953
2031	3,204	893	1,498	610	170	285	$ 92,536	$ 31,685	$ 152,953
2032	3,565	948	1,725	678	180	328	$ 92,536	$ 31,685	$ 152,953
2033	3,908	1,010	1,947	744	192	371	$ 89,458	$ 34,764	$ 152,953
2034	4,234	1,066	2,161	806	203	411	$ 89,458	$ 34,764	$ 152,953
2035	4,554	1,121	2,327	867	213	443	$ 89,458	$ 34,764	$ 125,340
2036	4,419	1,089	2,259	841	207	430		$ -	
2037	4,347	1,069	2,222	827	203	423		$ -	
2038	4,270	1,049	2,181	813	200	415		$ -	
2039	4,113	1,007	2,116	783	192	403		$ -	
2040	3,963	969	2,050	754	184	390		$ -	
2041	3,807	925	1,980	725	176	377		$ -	
2042	3,591	863	1,882	683	164	358		$ -	
2043	3,379	802	1,779	643	153	339		$ -	
2044	3,012	692	1,635	573	132	311		$ -	
2045	2,655	599	1,470	505	114	280		$ -	
2046	2,316	501	1,312	441	95	250		$ -	
2047	1,986	409	1,144	378	78	218		$ -	
2048	1,658	324	957	315	62	182		$ -	
2049	1,330	241	787	253	46	150		$ -	
2050	1,009	184	599	192	35	114		$ -	
2051	774	143	455	147	27	87		$ -	
2052	541	103	314	103	20	60		$ -	
2053	321	61	183	61	12	35		$ -	
2054	160	30	84	30	6	16		$ -	
2055	-	-	-	-	-	-		$ -	

G. Demand Response Forecast

Like the process for EE, the Company created six bundles for demand response based on level of achievement and technology so that DR could be modeled in Encompass in the same manner as a supply-side resource. These bundles included: (1) Base DR, Saver's Switch, (2) Base DR, Other DR, (3) Incremental DR, Saver's Switch, (4) Incremental DR, Other DR, (5) High Potential, Saver's Switch, and (6) High Potential, Other DR.

Consistent with past practice, the Company developed a Base DR Forecast from existing programs at historical growth rates, which was included in all baseline resource modeling as the first level of DR achievement. The Company then developed two levels of DR achievement incremental to the Base DR Forecast. The second level of DR achievement represents a higher level of growth rate necessary to achieve the required 400 MW of incremental DR by the end of 2023,[10] and a continuation of that level of achievement beyond 2023. This level of achievement, represented by bundles 1 through 4, is included in the Encompass model as required resources as ordered by the Commission. The third level of DR achievement, represented by bundles 5 and 6, is based on the Brattle DR Potential Study included in the 2019 IRP. This level of achievement exceeds the achievement of the ordered 400 MW by 2023 at a higher cost. These bundles are included in the Encompass model as selectable resources to determine the cost-effective level of future DR achievement.

Within each level of achievement, the costs and impacts of the Saver's Switch program and all other DR programs were modeled separately. This was done as the Saver's Switch program controls air-conditioning,[11] resulting in load reductions that differ significantly from the load reductions from all other DR programs which control a wide variety of loads. This results in a total of six bundles modeled bundles as described above (each level broken into specific technology and control characteristics). Similar to EE, each level of achievement represents an incremental amount of DR and is dependent on the preceding level of achievement being selected (i.e., third level of achievement for the Saver's Switch program cannot be selected unless the second level of achievement is selected).

[10] *See Order Approving Plan with Modifications and Establishing Requirements For Future Filings*, Docket No. E002/RP-19-368, April 15, 2022 at Order Point 2.A.2.
[11] Saver's Switch was used as a proxy for characterization of the resource, other programs such as AC Rewards also hold these characteristics.

Table F-7: Demand Response Forecast

	Incremental Demand (MW)						Incremental Costs ($000's $2023)					
Year	Bundle 1	Bundle 2	Bundle 3	Bundle 4	Bundle 5	Bundle 6	Bundle 1	Bundle 2	Bundle 3	Bundle 4	Bundle 5	Bundle 6
2024	686	339	176	56	24	70	29,538	20,204	13,834	4,362	3,490	10,068
2025	689	350	177	57	27	59	29,665	20,894	13,893	4,511	3,877	8,482
2026	691	362	178	59	28	59	29,756	21,584	13,936	4,660	4,057	8,500
2027	692	369	178	61	30	59	29,790	22,025	13,952	4,756	4,273	8,518
2028	692	375	178	61	31	59	29,732	22,357	13,924	4,827	4,522	8,537
2029	691	380	177	62	33	59	29,657	22,656	13,889	4,892	4,806	8,555
2030	687	385	176	63	36	60	29,367	22,960	13,753	4,957	5,124	8,573
2031	683	390	174	64	38	60	29,079	23,268	13,619	5,024	5,463	8,592
2032	679	395	173	65	40	60	28,795	23,580	13,486	5,091	5,825	8,610
2033	675	401	171	66	43	60	28,513	23,896	13,354	5,160	6,211	8,628
2034	671	406	170	67	46	60	28,234	24,216	13,223	5,229	6,622	8,647
2035	667	412	168	67	49	60	27,958	24,541	13,094	5,299	7,060	8,665
2036	663	417	167	68	52	60	27,684	24,870	12,966	5,370	7,527	8,684
2037	660	423	166	69	56	60	27,413	25,203	12,839	5,442	8,026	8,702
2038	657	428	164	70	59	61	27,145	25,541	12,713	5,515	8,557	8,721
2039	654	434	163	71	63	61	26,880	25,883	12,589	5,589	9,123	8,739
2040	650	440	162	72	68	61	26,617	26,230	12,465	5,664	9,727	8,758
2041	647	446	161	73	72	61	26,356	26,582	12,343	5,740	10,371	8,777
2042	644	452	160	74	77	61	26,098	26,938	12,223	5,816	11,058	8,795
2043	641	458	158	75	82	61	25,843	27,300	12,103	5,894	11,790	8,814
2044	638	464	157	76	87	61	25,590	27,666	11,985	5,973	12,570	8,833
2045	635	470	156	77	93	61	25,340	28,036	11,867	6,054	13,402	8,852
2046	632	477	155	78	99	62	25,092	28,412	11,751	6,135	14,290	8,871
2047	629	483	154	79	106	62	24,846	28,793	11,636	6,217	15,236	8,890
2048	626	489	153	80	113	62	24,603	29,179	11,522	6,300	16,244	8,909
2049	623	496	152	81	120	62	24,362	29,570	11,410	6,385	17,319	8,928
2050	620	503	150	82	128	62	24,124	29,967	11,298	6,470	18,466	8,947
2051	617	509	149	83	137	62	23,888	30,368	11,187	6,557	19,688	8,966
2052	615	516	148	85	146	62	23,654	30,776	11,078	6,645	20,992	8,985
2053	612	523	147	86	156	62	23,423	31,188	10,970	6,734	22,381	9,004
2054	609	530	146	87	166	63	23,193	31,606	10,862	6,824	23,863	9,023
2055	606	537	145	88	177	63	22,966	32,030	10,756	6,916	25,443	9,043

H. Demand and Energy Forecast

The Company's Fall 2023 load forecast is used as the base assumption in this Resource Plan. The forecast assumes adoption of Electric Vehicle (EV), new Large Commercial & Industrial (C&I) customer additions, Beneficial Electrification (BE), and demographic/economic growth. These load increases are netted against reductions in consumption resulting from Energy Efficiency to result in an overall energy requirements outlook that increases two percent per year in the 2024-2040 timeframe.

The "Load Forecast with required MN EE Bundles" shown in Table F-8 below is the starting point for the load inputs. In all modeling sensitivities, the "EE" is removed; the removal of the impact of this future and historic EE achievement, each of which has a 14-year life, impacts the load forecast through the end of the modeling period. The EE impact was subsequently locked in all sensitivities. The resulting forecast, before the impacts of EE achievement are added, is shown below in Table F-8 as "Forecast without required MN EE Bundles." The forecasts shown do not include the impact of DG solar.

Table F-8: Demand and Energy Forecast

Seasonal Peak Demand and Energy Forecast										
	Peak Seasonal Demand (MW) without required MN EE Bundles				Peak Seasonal Demand (MW) with required MN EE Bundles				Energy (GWh)	
Year	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Forecast without required MN EE Bundles	Forecast with required MN EE Bundles
2024	9,408	7,528	6,612	7,043	9,309	7,433	6,525	6,949	44,439	43,823
2025	9,526	7,633	6,715	7,143	9,328	7,438	6,551	6,975	45,459	44,308
2026	9,946	7,987	7,036	7,500	9,650	7,697	6,798	7,249	48,238	46,524
2027	10,311	8,299	7,377	7,808	9,922	7,919	7,060	7,479	50,235	47,973
2028	10,511	8,423	7,526	7,955	10,029	7,954	7,138	7,560	50,971	48,170
2029	10,643	8,540	7,596	8,018	10,112	8,030	7,124	7,541	51,661	48,339
2030	10,835	8,689	7,750	8,158	10,207	8,060	7,215	7,632	52,630	48,866
2031	11,040	8,850	7,913	8,314	10,354	8,155	7,304	7,723	53,659	49,436
2032	11,331	9,060	8,146	8,504	10,574	8,308	7,495	7,852	54,974	50,305
2033	11,573	9,285	8,428	8,679	10,748	8,466	7,724	7,968	56,363	51,291
2034	11,902	9,564	8,574	8,923	11,065	8,769	7,794	8,193	58,051	52,555
2035	12,212	9,836	8,851	9,185	11,312	8,984	8,021	8,407	59,665	53,763
2036	12,496	10,034	9,080	9,404	11,563	9,111	8,277	8,626	61,053	55,302
2037	12,686	10,218	9,392	9,577	11,768	9,311	8,599	8,811	62,319	56,674
2038	12,890	10,373	9,565	9,703	11,987	9,500	8,785	8,950	63,482	57,934
2039	13,088	10,517	9,786	9,858	12,218	9,696	9,046	9,131	64,569	59,222
2040	13,202	10,616	9,681	9,918	12,414	9,901	8,958	9,238	65,390	60,215
2041	13,296	10,691	9,807	9,989	12,489	9,942	9,190	9,317	66,124	61,161
2042	13,389	10,757	9,966	10,061	12,628	10,050	9,639	9,446	66,861	62,174
2043	13,461	10,807	10,401	10,119	12,743	10,142	10,093	9,554	67,480	63,066
2044	13,542	10,859	10,436	10,258	12,903	10,277	10,160	10,016	68,166	64,220
2045	13,594	10,890	11,361	10,809	13,058	10,408	11,102	10,558	68,749	65,264
2046	13,642	11,095	11,848	11,245	13,173	10,883	11,622	11,026	69,373	66,338
2047	13,676	11,500	12,318	11,657	13,251	11,311	12,133	11,475	69,885	67,276
2048	13,703	11,885	12,302	12,041	13,345	11,725	12,147	11,887	70,391	68,194
2049	13,712	12,324	13,307	12,509	13,423	12,194	13,180	12,383	70,830	69,056
2050	13,775	12,608	13,675	12,823	13,555	12,503	13,574	12,723	71,343	69,951
2051	13,990	12,868	13,970	13,142	13,915	12,790	13,884	13,056	71,715	70,602
2052	14,247	13,158	13,676	13,514	14,190	13,099	13,609	13,447	72,164	71,321
2053	14,462	13,398	14,548	13,640	14,426	13,351	14,504	13,595	72,532	71,958
2054	14,683	13,656	14,833	13,954	14,660	13,623	14,802	13,922	73,096	72,715
2055	14,916	13,949	15,125	14,265	14,907	13,929	15,107	14,246	73,717	73,528

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

High and low load sensitivity assumptions are summarized below in Table F-9. Our high load forecast sensitivity assumes increased BE, full achievement of Minnesota's "20% by 2030" goal for EV penetration with similar increases in EV adoption in other states served by NSP, and additional large data center loads locating in

Minnesota. All other assumptions are held the same as in the base case outlook. The resulting high load forecast is shown below in Table F-10. The low load sensitivity assumes increased adoption of rooftop solar generation, no beneficial electrification, slower adoption of EVs, and less new load from data centers than was assumed in the Base Case. The resulting low load forecast is show below in Table F-11.

Table F-9: High and Low Load Sensitivity Assumptions

Component	High Load Case	Low Load Case
Base Load	Base Case	Base Case
Solar	Base Case	High Solar
Demand-Side Management	Base Case	Base Case
Beneficial Electrification	High BE	No BE
Electric Vehicles	Full Achievement	Low Achievement
Large Commercial & Industrial Customers	High LCI	Low LCI

Table F-10: High Load Sensitivity

High Load Sensitivity					
	Peak Seasonal Demand (MW)				Energy (GWh)
Year	Summer	Fall	Winter	Spring	
2024	9,524	7,653	6,730	7,125	45,219
2025	9,716	7,844	6,884	7,282	46,739
2026	10,236	8,300	7,362	7,721	50,174
2027	10,823	8,823	7,857	8,202	53,786
2028	11,240	9,160	8,316	8,649	56,033
2029	11,454	9,368	8,345	8,708	57,219
2030	11,772	9,642	8,545	8,902	58,866
2031	12,152	9,979	8,876	9,229	61,193
2032	12,529	10,294	9,374	9,568	63,514
2033	12,884	10,620	9,902	9,919	65,948
2034	13,255	10,975	10,144	10,244	68,159
2035	13,626	11,339	10,582	10,576	70,377
2036	13,927	11,567	10,732	10,816	72,105
2037	14,191	11,856	11,224	11,098	74,060
2038	14,445	12,084	11,501	11,302	75,783
2039	14,721	12,325	11,890	11,543	77,563
2040	14,876	12,488	11,897	11,660	78,837
2041	15,002	12,594	12,700	12,070	79,976
2042	15,092	12,644	13,224	12,485	80,871
2043	15,200	12,964	13,848	13,097	81,948
2044	15,364	13,608	14,061	13,836	83,367
2045	15,500	14,370	15,484	14,619	84,760
2046	15,830	15,069	16,233	15,407	85,957
2047	16,567	15,813	17,062	16,250	87,274
2048	16,975	16,323	17,032	16,783	87,984
2049	17,754	17,205	18,645	17,712	89,420
2050	18,239	17,670	19,252	18,264	90,570
2051	19,021	18,322	19,945	18,891	91,855
2052	19,427	18,756	19,618	19,433	92,801
2053	19,784	19,122	20,850	19,725	93,655
2054	20,153	19,539	21,295	20,208	94,703
2055	20,541	19,967	21,748	20,689	95,810

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

Table F-11: Low Load Sensitivity

Low Load Sensitivity					
	Peak Seasonal Demand (MW)				Energy (GWh)
Year	Summer	Fall	Winter	Spring	
2024	9,401	7,521	6,606	7,038	44,394
2025	9,513	7,618	6,702	7,134	45,146
2026	9,821	7,863	6,905	7,382	46,766
2027	9,970	7,963	7,029	7,476	47,359
2028	10,153	8,070	7,150	7,601	47,964
2029	10,264	8,165	7,213	7,659	48,502
2030	10,431	8,287	7,336	7,775	49,267
2031	10,602	8,412	7,464	7,893	50,036
2032	10,827	8,564	7,611	8,034	51,006
2033	10,993	8,713	7,813	8,162	52,005
2034	11,244	8,906	7,956	8,355	53,243
2035	11,490	9,110	8,168	8,545	54,419
2036	11,727	9,260	8,328	8,697	55,446
2037	11,878	9,406	8,526	8,810	56,408
2038	12,044	9,524	8,653	8,879	57,267
2039	12,207	9,633	8,820	8,995	58,042
2040	12,287	9,687	8,697	9,021	58,545
2041	12,350	9,714	8,752	9,062	58,984
2042	12,415	9,736	8,810	9,107	59,436
2043	12,463	9,750	8,957	9,137	59,795
2044	12,527	9,771	9,014	9,146	60,239
2045	12,565	9,773	9,109	9,170	60,609
2046	12,601	9,778	9,463	9,185	61,025
2047	12,626	9,767	9,805	9,374	61,348
2048	12,650	9,752	9,751	9,521	61,693
2049	12,661	9,799	10,567	9,884	62,015
2050	12,711	10,048	10,891	10,156	62,422
2051	12,744	10,272	11,146	10,511	62,698
2052	12,803	10,533	10,906	10,779	63,056
2053	12,017	10,748	11,647	10,874	63,341
2054	12,059	10,977	11,899	11,155	63,820
2055	12,207	11,243	12,158	11,435	64,358

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

I. Fuel and Market Price Forecasts

To derive the forecast of monthly delivered gas prices at Ventura Hub, the Company uses a combination of market indicators such as New York Mercantile Exchange (NYMEX) and long-term price forecasts published by highly respected, industry-leading sources such as Wood Mackenzie and S&P Global. The forecast is NYMEX-based for the first few years, and then it transitions into blending the NYMEX curve with the vendor forecasts to develop a composite forecast. The Company used the following weightings for each component at various time intervals:

Period	NYMEX	S&P Global	Wood Mackenzie
Balance of the year + 2 years	100%	0%	0%
Years 3 and Beyond	25%	37.5%	37.5%
	10 yr trendline extension		

The final years of the forecasts vary between sources; Wood Mackenzie and S&P Global provide data through 2050, and NYMEX through 2035. The Company uses linear extrapolation to extend the data of each forecast out to 2050 and beyond. The Ventura Hub is later adjusted for specific delivery costs at each generating unit to develop the final model inputs.

Coal price forecasts at mine mouth are based on a combination of the short-term spot market forecast from Coaldesk, LLC in the near term and a simple average of long-term coal price forecasts provided by Wood Mackenzie and S&P Global. Added to the coal price forecast at mine mouth, which is just for the coal commodity, are: transportation charges (rail and diesel fuel), SO_2 costs, freeze control, and dust suppressant, as required. Coal price forecasts are shown below in Table F-12.

Table F-12: Coal Price Forecasts

Coal Price Forecast		
Year	AS King (Delivered) $/mmBtu	Sherco (Delivered) $/mmBTU
2024	$2.62	$2.37
2025	$2.71	$2.52
2026	$2.78	$2.57
2027	$2.81	$2.60
2028	$2.89	$2.67
2029	$2.95	$2.72
2030	$3.01	$2.78

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. To derive the forecast of monthly On and Off-peak electricity prices, the Company uses a simple average of On and Off-peak power price forecasts provided by Wood Mackenzie and S&P Global. Table F-13 below shows the market prices under zero CO_2 cost assumptions. To generate the hourly market prices, the Company uses the hourly energy price forecasts from the Horizons Energy EnCompass National Database, specifically the energy prices at the MISO-ND-MN node and scales it to match the monthly On and Off-peak price forecasts in Table F-13.

High and low-price sensitivities were performed by adjusting the base forecast up and down by 50 percent.

Table F-13: Gas and Market Price Forecast

	Base Forecast			Low Forecast			High Forecast		
	Gas Price ($/mmBTu)	Market Price ($/MWh)		Gas Price ($/mmBTu)	Market Price ($/MWh)		Gas Price ($/mmBTu)	Market Price ($/MWh)	
Year	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2024	$3.36	$39.74	$30.58	$1.68	$19.87	$15.29	$5.04	$59.61	$45.88
2025	$3.95	$34.84	$26.39	$1.98	$17.42	$13.19	$5.93	$52.26	$39.58
2026	$3.71	$38.11	$28.81	$1.86	$19.05	$14.41	$5.57	$57.16	$43.22
2027	$4.07	$38.04	$29.23	$2.03	$19.02	$14.61	$6.10	$57.05	$43.84
2028	$4.12	$37.25	$29.02	$2.06	$18.62	$14.51	$6.18	$55.87	$43.53
2029	$4.09	$35.21	$28.30	$2.05	$17.60	$14.15	$6.14	$52.81	$42.45
2030	$4.06	$35.52	$29.11	$2.03	$17.76	$14.55	$6.09	$53.28	$43.66
2031	$4.07	$35.57	$30.60	$2.03	$17.78	$15.30	$6.10	$53.35	$45.90
2032	$4.16	$35.72	$31.58	$2.08	$17.86	$15.79	$6.24	$53.59	$47.37
2033	$4.31	$34.78	$31.79	$2.15	$17.39	$15.89	$6.46	$52.17	$47.68
2034	$4.49	$34.15	$32.02	$2.24	$17.08	$16.01	$6.73	$51.23	$48.02
2035	$4.62	$33.96	$32.59	$2.31	$16.98	$16.30	$6.93	$50.94	$48.89
2036	$4.68	$33.21	$32.58	$2.34	$16.60	$16.29	$7.01	$49.81	$48.87
2037	$4.81	$33.60	$32.86	$2.41	$16.80	$16.43	$7.22	$50.39	$49.30
2038	$4.95	$32.83	$33.05	$2.48	$16.41	$16.52	$7.43	$49.24	$49.57
2039	$5.07	$32.93	$33.28	$2.54	$16.47	$16.64	$7.61	$49.40	$49.91
2040	$5.37	$33.04	$35.28	$2.68	$16.52	$17.64	$8.05	$49.56	$52.92
2041	$5.53	$35.19	$37.40	$2.77	$17.59	$18.70	$8.30	$52.78	$56.10
2042	$5.62	$34.30	$36.76	$2.81	$17.15	$18.38	$8.44	$51.45	$55.14
2043	$5.86	$34.04	$37.19	$2.93	$17.02	$18.60	$8.79	$51.05	$55.79
2044	$6.19	$34.50	$37.35	$3.10	$17.25	$18.68	$9.29	$51.76	$56.03
2045	$6.48	$35.08	$41.40	$3.24	$17.54	$20.70	$9.72	$52.62	$62.10
2046	$6.61	$36.25	$40.19	$3.30	$18.12	$20.10	$9.91	$54.37	$60.29
2047	$6.77	$36.81	$42.23	$3.38	$18.40	$21.11	$10.15	$55.21	$63.34
2048	$6.92	$36.70	$43.07	$3.46	$18.35	$21.54	$10.37	$55.05	$64.61
2049	$7.19	$37.53	$44.27	$3.59	$18.77	$22.13	$10.78	$56.30	$66.40
2050	$7.54	$37.61	$46.10	$3.77	$18.81	$23.05	$11.31	$56.42	$69.16
2051	$7.68	$40.59	$47.30	$3.84	$20.29	$23.65	$11.51	$60.88	$70.95
2052	$7.89	$41.75	$48.64	$3.95	$20.87	$24.32	$11.84	$62.62	$72.97
2053	$8.11	$42.91	$49.99	$4.06	$21.45	$25.00	$12.17	$64.36	$74.99
2054	$8.33	$44.07	$51.36	$4.17	$22.03	$25.68	$12.50	$66.10	$77.04
2055	$8.55	$45.22	$52.72	$4.28	$22.61	$26.36	$12.83	$67.84	$79.08

J. Baseload Retirement "Leave Behind" Costs

The Company includes "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of baseload resource retirements. For the retiring coal units, these costs are largely attributed to synchronous condensers that will likely be needed to maintain grid stability. For the nuclear units, the Company conducted a "leave behind" study to determine the transmission system impacts of the nuclear plants' retirement. The reinforcement costs are included as capital expenditure based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated by the Company. We applied these costs in the modeling as soon as the resource is retired to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2023).

- King: $50 million
- Sherco 1: $50 million
- Sherco 2: $50 million
- Sherco 3: $50 million

Table F-14: Nuclear Leave Behind Costs

[PROTECTED DATA BEGINS

Baseload Scenario Name	Nuclear Unit	Retirement Date	Leave Behind Cost (2023$)	Year(s) when LBC incurs
Reference Case	Monticello	2040		2035-2040
	Prairie Island	2033/34		2028-2033
Prairie Island Extension	Monticello	2040		2036-2040
	Prairie Island	2053/54		N/A
Extend All Nuclear	Monticello	2050		2045-2050
	Prairie Island	2053/54		2048-2053

PROTECTED DATA ENDS]

K. Market Capacity Price

Surplus capacity up to 500 MW can receive surplus capacity credit and is priced at the avoided capacity cost of a generic greenfield H-Class combustion turbine on an economic carrying charge basis.

Table F-15: Market Capacity Price

Surplus Capacity Credit																
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
$/kw-mo	8.75	8.92	9.10	9.28	9.47	9.66	9.85	10.05	10.25	10.45	10.66	10.88	11.09	11.32	11.54	11.77
	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
$/kw-mo	12.01	12.25	12.49	12.74	13.00	13.26	13.52	13.79	14.07	14.35	14.64	14.93	15.23	15.53	15.84	16.16

L. Seasonal Accredited Capacity Assumptions for Wind, Solar, and Battery Resources

The seasonal accredited capacity (SAC) values for wind, solar, and battery resources vary according to whether a resource is already in existence or is a new resource option for the model. The Effective Load Carrying Capability (ELCC) for existing NSP wind and solar resources is based on the 2023-2024 MISO planning year seasonal accreditation capacity[12] with an annual degradation assumption for solar resources.[13] For years beyond 2024, the seasonal accredited capacity of existing wind, solar, and battery resources trends over multiple years so it meets the assumptions used in MISO's November 2022 Regional Resource Assessment (RRA) as depicted in Figures F-1, F-2, and F-3 below. As outlined by MISO, there was an unexpected deviation from the anticipated declining trend in ELCC when more of a resource type is added to the system. Specifically, the average solar ELCC for the winter season increased from one percent in 2031 to 11 percent in 2041. This increase can be attributed to the hour in which risk emerged during the winter months. In 2041, the evening risk materialized two hours earlier than it did in 2031. This change, attributed to low wind output, resulted in a ten percent change to the solar ELCC outcome when using the average ELCC methodology as described further below.[14]

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12 MISO Planning Year 2023-2034 Wind and Solar Capacity Credit Report (March 2023). Available at https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf.

13 The seasonal accredited capacity percentages are applied to the installed capacity of each existing NSP resource. In the case of solar resources, the maximum capacity declines slightly each year, due to slight degradation in the installed solar modules. NSP incorporates a 0.5 percent decrease in existing solar resources' installed capacity to mimic this effect in addition to the ELCC assumptions described in this section.

14 MISO Regional Resource Assessment (November 2022) at p. 45. Available at https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf.

Figure F-1: Average seasonal ELCC for Existing Wind Resources[15]

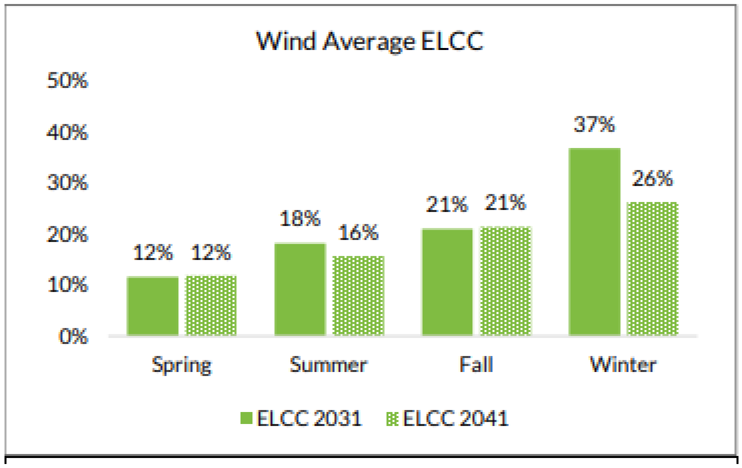
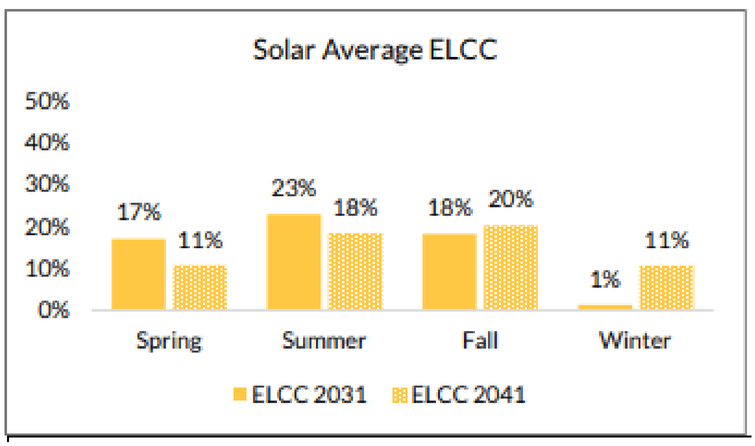
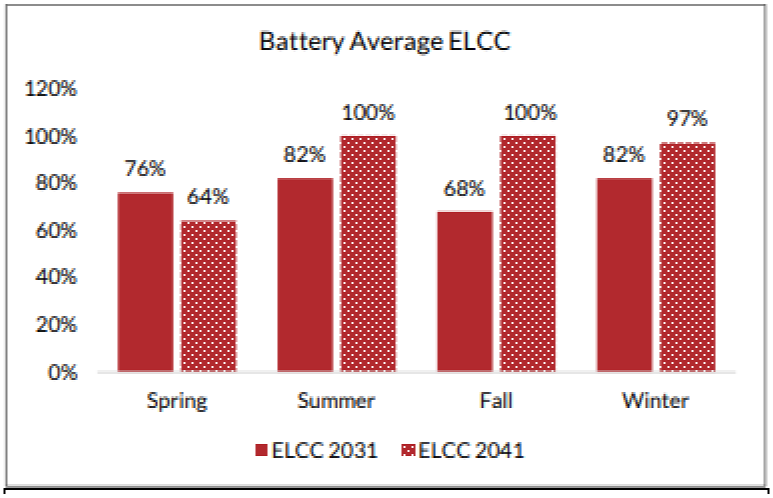


Figure F-2: Average seasonal ELCC for Existing Solar Resources[16]



[15] *Id.* at p. 47.
[16] *Id.* at p. 45.

Figure F-3: Average seasonal ELCC for Battery Resources[17]



The seasonal accreditation assumptions for generic wind, solar, battery, and solar + battery hybrid resources are shown on Table F-16. The seasonal accreditation assumptions for generic wind resources are based on values used in MISO's 2022 and 2023 Regional Resource Assessment (RRA); and stem from MISO's March 2023 Planning Year 2023-2024 Wind and Solar Capacity Credit Report.

The seasonal accreditation for generic solar resources starts with the values in the MISO 2023/2024 PY Planning Reserve Margin and Local Reliability Requirements. These values then trend to the long-term ELCC assumptions in the MISO November 2022 RRA.

The battery seasonal accreditation starts with the MISO October 2023 Resource Adequacy Business Practice Manual (BPM) section 4.2.9.4, which provides the five percent forced outage (95% accredited capacity assumptions) for new energy storage resources. The accreditation trends over several years from the 95% capacity accreditation to the long-term assumptions for battery storage resources in the MISO November 2022 RRA. The MISO battery accreditation is based on a four-hour battery. In the case of a 10-hour battery, we conservatively apply the same value since MISO does not provide an ELCC for a 10-hour duration.

The solar plus battery hybrid accreditation value is calculated using the methodology in the MISO October 2023 Resource Adequacy Business Practice Manual BPM,

[17] *Id.* at p. 51.

Section 4.2.11. This section details the Phase I "sum of parts" method for hybrid systems, applying it to the assumed generic solar and storage units in our model. For each year within the modeling horizon, the "sum of parts" methodology from the current MISO BPM is replicated. However, in this case, the components combined are the standalone storage and solar generic units, each component part – solar and storage – with accreditation assumptions that trend over time to align with the long-term November 2022 MISO RRA values for standalone storage and standalone solar.[18]

A key trend over time here is that many of the seasonal values for different generic resource types trend down from the single year MISO PY 2023/2034 to MISO PY 2031/2032 and then back up again by MISO PY 2041/2042. This occurs in part because the studies for MISO PY 2023/2024 assumptions differ from those for the later years and also because of the methodology and assumptions being used for PY 2031/2032 and PY 2041/2041.

In the case of MISO PY 2031/2032 and MISO PY 2041/2042 variations, ELCC assumptions for intermittent resources are affected by the system-wide generation resource mixes MISO projects for those years. Additionally, the average ELCC method MISO uses for this study heavily depends on projected resource output for a few key Loss of Load Probability (LOLP) hours each season. While MISO notes that average ELCC methodology "may not be adequate for a system with large amounts of intermittent generation" and that "changes to the accreditation methodology applied to non-thermal technologies are currently being considered by MISO's Resource Adequacy Subcommittee (RASC) stakeholders," in the absence of other long-term data, the Company has adopted these ELCC values for its long-term modeling purposes.

[18] The total resource accreditation for hybrid units used this method instead of matching to MISO 2022 RRA values for hybrids because the sizes of the solar and storage components relative to total asset size that MISO had used in their analysis were unknown and may have differed from the hybrid generic unit configuration used by the Company in IRP modeling.

Table F-16. Generic Wind, Solar, Battery, and Solar + Battery Hybrid Resource ELCC

PY 2023/2024

Generic Resource Type	Summer	Fall	Winter	Spring
Wind[19]	18.1%	23.1%	40.3%	23.0%
Solar[20]	45.4%	25.3%	6.3%	15.0%
Battery	95.0%	95.0%	95.0%	95.0%
Solar + Battery Hybrid	52.6%	43.3%	33.3%	37.9%

PY 2031/2032

Generic Resource Type	Summer	Fall	Winter	Spring
Wind	18.0%	21.0%	37.0%	12.0%
Solar	23.0%	18.0%	1.0%	17.0%
Battery	82.0%	68.0%	82.0%	76.0%
Solar + Battery Hybrid	38.0%	30.9%	26.4%	32.9%

PY 2041/2042

Generic Resource Type	Summer	Fall	Winter	Spring
Wind	16.0%	21.0%	26.0%	12.0%
Solar	18.0%	20.0%	11.0%	11.0%
Battery	100.0%	100.0%	97.0%	64.0%
Solar + Battery Hybrid	41.1%	42.1%	36.4%	26.0%

M. Spinning Reserve Requirement

The total spinning requirement in the model consists of spinning reserve and supplemental reserve. Spinning reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. Supplemental reserve is the off-line capacity capable of quick start within 10 minutes. On an hourly basis, each ancillary type for NSP is calculated as the NSP load ratio of the published MISO System Wide Ancillary Requirements. The level of total spinning requirement modeled is 125.17 MW and is based on a 12-month historical average in 2022.

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[19] MISO Planning Year 2023-2024 Wind and Solar Capacity Credit Report. (March 2023). Available at: https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf

[20] MISO 2023/24 PY Planning Reserve Margin and Local Reliability Requirements – Final Results. October 3, 2022. Available at: https://cdn.misoenergy.org/20221003%20LOLEWG%20Item%2003%20PY%202023-24%20Final%20LOLE%20Study%20Results626468.pdf.

N. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In EnCompass, we use the value of $1,000,000/MWh. Emergency energy is a "soft constraint" in EnCompass modeling that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small, required run time – are utilized before emergency energy.

O. Cost Assumptions for Transmission Tie Lines and New Resource Interconnections

Interconnection costs of $250/kw[21] are included in addition to the capital costs and operating expenses for utility-scale generic resource options.[22] These interconnection costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system and are the "behind the fence" costs associated with substation and representative gen-tie construction.

In this IRP, a new distribution-interconnected resource, solar used to comply with the 3% Distributed Solar Energy Storage (DSES) legislation, also includes an interconnection cost as part of its total modeled cost. Costs from our recently filed Integrated Distribution Plan (IDP) were used as shown in Table F-17.[23]

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[21] The basis for this cost assumption is discussed in Appendix L: System Planning Integration.

[22] Generic resources interconnecting to the Sherco and King transmission tie-lines do not have this cost as part of their capital cost assumption since they will not need to have a new, dedicated Generator Interconnection Agreement (GIA) with MISO.

[23] *See* Integrated Distribution Plan, Appendix I: Distribution System Upgrades, November 1, 2023, Docket No. E002/M-23-452, for more information on the development of interconnection cost assumptions.

Table F-17: 3% DSES Interconnection Cost Assumptions

Years	3% Distributed Solar Energy Standard Interconnection Cost Assumption (Nominal $/kW)
2024-2029	$225
2030-2040	$184
2041-2055	$149

Regarding transmission tie-lines, in the Alternate Plan, we proposed to build transmission tie-lines from our Sherco and King sites that can interconnect incremental renewable and/or firm dispatchable resources. The total costs of the tie lines include capital costs plus VAR support, such as installing tie-line synchronous condensers and series compensation of the lines; while these are general cost estimates and subject to change during detailed project design, they are in line with the Company's experience on other projects. The total capacities of generator reuse are based on the existing interconnection rights at Sherco and King.

Table F-18: Sherco and King Gen-tie Assumptions

	Total Capital Costs (in 2023 Dollars)	Interconnection Rights
Sherco gen-tie	$1.139 billion	1996 MW
King gen-tie	$177 million	591 MW

Table F-19: Retiring Coal Units and Selection Windows for Gen-tie Resources[24]

Retiring Unit	Open Interconnection	Replacement Resource Window	Replacement Resources Allowed
Sherco 2	710 MW	2024-2026	Solar[25]
Sherco 1	720 MW	2027-2029	Solar, and Wind + ~400 MW of CTs (2028-2029)
Sherco 3	566 MW	2030-2032	Solar + Wind
AS King	591 MW	2028-2030	Solar only

[24] It was discovered that we inadvertently transposed the interconnection values for Sherco coal units 1 and 2 in the previous IRP. This has been corrected in this IRP model. The overall replacement MW indicated in the IRP Order for Units 1 and 2 together is correct and has not changed.

[25] Collectively, the Sherco Solar 1, 2, and 3 projects reutilize the interconnection capacity made available with the retirement of Sherco Coal Unit 2.

P. Distributed Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts and an estimated ramp up of resources that comply with the Distributed Solar Energy Standard (DSES). Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a 25-year service life.

Table F-20: Distributed Solar Nameplate capacity Forecast

Distributed Solar (Nameplate MWac)					
Year	CSG Legacy (2016-2024)	Non-Legacy CSGs	Customer Sited DG Solar	Distributed Solar Energy Standard (3%)	Total
2024	881	18	192		1,091
2025	877	100	239		1,215
2026	872	199	284		1,356
2027	868	298	325	62	1,553
2028	864	377	364	250	1,854
2029	859	455	382	373	2,069
2030	855	533	422	497	2,306
2031	851	610	481	494	2,436
2032	846	667	551	506	2,570
2033	842	724	610	517	2,693
2034	838	780	652	529	2,799
2035	834	836	683	540	2,893
2036	830	892	729	551	3,002
2037	825	948	792	562	3,127
2038	821	1,003	851	574	3,249
2039	817	1,058	919	585	3,379
2040	813	1,113	947	596	3,468
2041	841	1,167	993	607	3,608
2042	1,022	1,221	1,056	618	3,917
2043	1,246	1,275	1,167	629	4,316
2044	1,372	1,329	1,272	640	4,612
2045	1,478	1,382	1,353	650	4,864
2046	1,511	1,435	1,420	661	5,028
2047	1,534	1,488	1,540	672	5,233
2048	1,557	1,540	1,735	682	5,515
2049	1,554	1,609	1,906	693	5,762
2050	1,547	1,733	2,075	704	6,058
2051	1,539	1,872	2,210	714	6,335
2052	1,531	2,011	2,310	724	6,577
2053	1,524	2,132	2,520	735	6,911
2054	1,516	2,252	2,797	745	7,310
2055	1,508	2,371	3,051	755	7,686

*Customer sited DG solar capacity is reported as the max capacity of each year.

Table F-21: Distributed Solar Cost Forecast[26]

Distributed Solar ($nominal/MWh)				
Year	CSG Legacy (2016-2024)	Non-Legacy CSGs	Customer Sited DG Solar	Distributed Solar Energy Standard (3%)
2024	121.25	121.25	144.84	
2025	124.06	124.06	147.74	
2026	126.94	126.94	150.69	
2027	129.89	129.89	153.71	51.54
2028	132.90	132.90	156.78	50.79
2029	135.98	135.98	159.92	50.36
2030	139.14	139.14	163.11	49.33
2031	142.36	142.36	166.38	49.33
2032	145.67	145.67	169.70	49.20
2033	149.05	149.05	173.10	49.05
2034	152.51	152.51	176.56	48.88
2035	156.04	156.04	180.09	48.68
2036	159.66	159.66	183.69	48.49
2037	163.37	163.37	187.37	48.31
2038	167.16	167.16	191.11	48.14
2039	171.04	171.04	194.94	47.98
2040	175.00	175.00	198.83	47.82
2041	179.06	179.06	202.81	47.61
2042	183.22	183.22	206.87	47.41
2043	187.47	187.47	211.00	47.22
2044	191.82	191.82	215.22	47.12
2045	196.27	196.27	219.53	47.12
2046	200.82	200.82	223.92	47.29
2047	205.48	205.48	228.40	47.46
2048	210.25	210.25	232.97	47.62
2049	215.13	215.13	237.63	47.77
2050	220.12	220.12	242.38	47.93
2051	225.22	225.22	247.23	48.09
2052	230.45	230.45	252.17	48.27
2053	235.79	235.79	257.21	48.46
2054	241.27	241.27	262.36	48.66
2055	246.86	246.86	267.60	48.87

[26] Costs for each resource are derived from the following data sources: (1) CSG: Value of Solar Bill Credit Rates, (2) Customer Sited DG Solar: Xcel Energy A50 Rate Code, and (3) Distributed Solar Energy Standard (3 percent): combination of NREL ATB Utility-Scale Solar and Distributed Commercial PV resource types.

Q. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Seasonal Accredited Capacity Ratings
d. Minimum Capacity Rating
e. Heat Rate Profiles
f. Variable O&M
g. Start up fuel usage and start up charge
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

R. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Accredited Capacity Ratings
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Start up fuel usage and start up charge
j. Maintenance Schedule
k. Forced Outage Rate
o. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter

l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Seasonal Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Whether curtailed energy is compensable or not

T. Park Potential profiles for modeling wind and solar generation on the NSP System

This section discusses the process used to create Park (i.e., wind or solar farm) Potential profiles of wind and solar generation for Xcel Energy's upper Midwest region.

1. Annual Expected Park Potential

The Company combined monthly generation and curtailment data to derive the monthly Park Potential for each renewable generation Commercial Pricing Node (CP Node) from January, 2018 through November, 2022. The monthly Park Potentials were summed on a rolling 12-month basis to derive 48 annual Park Potential values. The Company averaged the 48 annual values to determine the annual expected Park Potential value for each CP Node. For renewable generation without sufficient historic data, the most recent Energy Production Estimate (EPE) from pre-construction developer software or the Annual Committed Energy from the Purchase Power Agreement was used as the annual PP value.

2. Monthly Allocation of Annual Park Potential

For new wind plants, the pre-construction developer software uses 30 years' worth of meteorological weather reanalysis data to determine the expected monthly generation expressed as a percentage of the annual EPE. The Company used the average of the monthly percentages from new wind plants to allocate the CP Node annual Park Potential values to each calendar month. For solar plants, the Company calculated the ratio of monthly Park Potential relative to annual Park Potential for each month from the years 2018-2022. Table F-22 shows the monthly allocations for wind and solar plants expressed as a percentage of the annual expected Park Potential.

Table F-22: Monthly Percentage of Annual Wind and Solar Plant Park Potential

Month	Wind Allocation (%)	Solar Allocation (%)
January	9.1	3.7
February	8.2	5.4
March	9.1	9.0
April	9.4	10.0
May	9.1	11.9
June	7.7	13.2
July	6.3	13.1
August	6.1	11.6
September	7.7	9.2
October	9.1	6.6
November	9.2	3.8
December	9.0	2.7

3. *Hourly Allocation of Monthly Park Potential*

For most wind plants, the Company has wind speed data measured at the turbine anemometers.[27] The Company gathered hourly averaged wind speed data from 2020 for each wind CP Node and used empirical power conversions specific to those CP Nodes to convert the hourly wind speed to hourly generation. The summed monthly generation for each CP Node was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. A constant wind speed adjustment was made to each hour so that the sum of the hourly generation based on the hourly wind speed data matched the monthly allocation of the annual Park Potential.

[27] The Company has turbine wind speed data for approximately 91% of Company-controlled wind generation capacity.

For wind generation at CP Nodes without wind speed data, the Company generated a single empirical power conversion derived from the simple average of all wind speed data for each hour in 2021 and the paired sum-of-generation from all CP Nodes without wind speed data. For each of these CP Nodes, the Company calculated the pro rata ratio of the CP Node annual Park Potential relative to the sum of annual Park Potentials for all CP Nodes without wind speed data. A constant wind speed adjustment was applied to the system average wind speed profile for each month so that the resulting generation profile matched the monthly allocation of the sum of annual Park Potentials for all CP Nodes without wind speed data. Each CP Node without wind speed data was assigned their pro-rata share of this hourly generation profile for each month.

For solar generation, the Company used hourly irradiance and generation data from 2020 for each solar plant and used empirical power conversions to convert the hourly irradiance to hourly generation. The summed monthly generation for each plant was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. An irradiance adjustment was made to each hour in a given month so that the sum of the hourly generation based on the hourly irradiance data matched the monthly allocation of the annual Park Potential.

For plants without historic irradiance or generation data, the Company used 2020 hourly irradiance data for each plant location sourced from the National Solar Radiation DataBase (NSRDB) maintained by the National Renewable Energy Laboratory (NREL). The same process was used to derive the hourly generation profiles for these solar plants as for the existing solar plants in the Company's portfolio of renewable generation.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal assumptions are based on the Company's internal estimates informed by external consultants and original equipment manufacturers. Generic renewable and battery costs, as well as battery operational characteristics such as cycle limit and Round-Trip Efficiency (RTE) are from National Renewable Energy Laboratory (NREL) 2023 Annual Technology Baseline (ATB) data. High and low technology cost sensitivities are created based on NREL ATB "Conversative" and "Advanced" forecasts. We also have a sensitivity where the wind, solar and solar + battery hybrid LCOEs prior to 2030 are adjusted to match the 2023 Q1-Q3 actual PPA prices in MISO, reported in the Edison Energy Global Renewable Market Update quarterly reports. Utility-scale wind, solar, solar plus battery hybrid and battery costs, with and without interconnection costs for the base case and all sensitivities, are shown in Tables F-24 – F-38.

The costs used for wind, solar, and storage assets fully incorporate the Production Tax Credit (PTC) or Investment Tax Credit (ITC) in the Inflation Reduction Act (IRA). The costs of wind and solar resources selected to replace the interconnection capacity of Sherco and King are calculated without incremental transmission costs (as the gen-tie costs are already accounted for elsewhere in the model). In addition, we do not make cost adjustments to the Company's owned units selected to replace the retired coal capacities. The IRA allows the transferability of tax credits, allows utilities to elect out from normalization for storage facilities, and allows owners of solar facilities to claim a PTC in lieu of the ITC, which is subject to normalization. All of these combine to create a more level playing field for utilities to build/own solar and storage assets.

Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. Seasonal Accredited Capacity
d. Minimum Capacity Rating
e. Heat Rate Profiles
f. Variable O&M
g. Fixed O&M
h. Maintenance Schedule
i. Forced Outage Rate
j. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter
k. Contribution to spinning reserve
l. Fuel prices
m. Fuel delivery charges

Renewable

a. Contract term

b. Name Plate Capacity
c. Seasonal Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Whether curtailed energy is compensable or not

Table F-23: Thermal Generic Information (Costs in 2023 Dollars)

Thermal Generic Information			
Resource	**Generic CT**	**Generic CT**	**Reciprocating Engine**
Technology	7H DF	7F DF	Medium Speed reciprocating engine DF
Location Type	Greenfield	Greenfield	Greenfield
Cooling Type	Dry	Dry	Dry
On Site Fuel Storage Full Load Duration (hours)	48	48	50
Book life	40	40	40
Nameplate Capacity (MW)	374	225	108
Summer Peak Capacity (MW)	331	210	108
Minimum Emissions-Compliant Load Capacity (MW)	149	106	7.0
Capital Cost ($000) 2023$	$280,000	$215,000	$316,000
Capital Cost ($/kW) 2023$	$749	$954	$2,926
Ongoing Capital Expenditures ($000-yr) 2023$	$1,784	$1,320	$108
Ongoing Capital Expenditures ($/kW-yr) 2023$	$4.77	$5.86	$1.00
Fixed O&M Cost ($000/yr) 2023$	$1,524	$1,463	$1,277
Variable O&M Cost ($/MWh) 2023$	$1.20	$1.26	$6.30
Interruptible Gas Demand Cost ($/mmBTU) 2023$	$0.49	$0.49	$0.49
Startup Cost ($/start)	$5,809	$3,872	$0.00
Cold Startup Fuel Usage (mmBTU/start)	110	73	$0.00
Summer HHV Heat Rate 100% Loading (btu/kWh)	9,264	10,113	8,275
Summer HHV Heat Rate 75% Loading (btu/kWh) (70% loading for reciprocating engine)	9,738	10,567	8,739
Summer HHV Heat Rate 50% Loading (btu/kWh)	11,120	12,711	9,437
Summer HHV Heat Rate MECL Loading (btu/kWh)	11,558	12,592	9,979
Winter HHV Heat Rate 100% Loading (btu/kWh)	9,066	10,157	8,275
Winter HHV Heat Rate 75% Loading (btu/kWh) (70% loading for reciprocating engine)	9,647	10,952	8,739
Winter HHV Heat Rate 50% Loading (btu/kWh)	10,964	12,924	9,437
Winter HHV Heat Rate MECL Loading (btu/kWh)	11,443	12,837	9,979
Forced Outage Rate	3%	3%	3%
Maintenance (weeks/yr)	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118
CO Emissions (lbs/MWh)	0.14	0.15	0.12
SO2 Emissions (lbs/MWh)	0.00	0.02	0.09
NOx Emissions (lbs/MWh)	0.90	0.32	0.08
PM10 Emissions (lbs/MWh)	0.03	0.03	0.10
PM2.5 Emissions (lbs/MWh)	0.03	0.03	0.10
Notes:			
1. Summer capacity and heat rate for generic 7H CT are based on an ambient temperature of 95 degrees F, 40% relative humidity.			
2. Winter capacity and heat rate for generic 7H CT are based on an ambient temperature of -6 degrees F, 60% relative humidity.			
3. Summery capacity and heat rate for generic 7F CT are based on an ambient temperature of 86.7 degrees F, 59.6% relative humidity.			
4. Winter capacity and heat rate for generic 7F CT are based on an ambient temperature of 18 degrees F, 74.2% relative humidity.			
5. Capacity and heat rate for generic reciprocating engine are based on an inlet air temperature of 86.7 degree F, 59.6% relative humidity.			

Table F-24: Renewable and Battery Generic Information

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Utility Scale PV + Battery**	**Utility Scale Battery**
Representative Plan Size (MW)	200 MW	100 MWDC*	130 MWDC Solar + 60 MWAC Battery, 100 MWAC Inverter	60 MW
Capacity Factor	44.3%	23.0%	Subject to dispatch	Subject to dispatch
Book life (years)	30	30	30	15
PTC or ITC applied	PTC	PTC	ITC	ITC
Electric Transmission Delivery ($/kW)	250	250	250	250
Storage Characteristics	NA	NA	NA	1 cycle/day; 85% RTE

*Solar capacity assumes 0.5 percent annual degradation.

Table F-25: Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost				
	Capex with TRX ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)	
Year	4 hr duration	10 hr duration	4 hr duration	10 hr duration
2024	$2,004.38	$4,101.77	$43.48	$95.91
2025	$1,825.17	$3,688.93	$38.86	$85.46
2026	$1,810.38	$3,632.95	$38.36	$83.92
2027	$1,794.27	$3,573.10	$37.82	$82.29
2028	$1,776.78	$3,509.23	$37.24	$80.55
2029	$1,757.86	$3,441.16	$36.62	$78.71
2030	$1,737.48	$3,368.73	$35.97	$76.75
2031	$1,749.60	$3,383.17	$36.12	$76.96
2032	$1,761.50	$3,396.87	$36.27	$77.15
2033	$1,773.19	$3,409.80	$36.40	$77.32
2034	$1,784.63	$3,421.91	$36.53	$77.46
2035	$1,795.83	$3,433.19	$36.65	$77.58
2036	$1,806.76	$3,443.58	$36.76	$77.68
2037	$1,817.42	$3,453.06	$36.86	$77.75
2038	$1,827.77	$3,461.58	$36.94	$77.79
2039	$1,837.82	$3,469.10	$37.02	$77.80
2040	$1,847.53	$3,475.59	$37.08	$77.78
2041	$1,856.90	$3,481.00	$37.14	$77.74
2042	$1,865.91	$3,485.29	$37.17	$77.66
2043	$1,874.54	$3,488.42	$37.20	$77.55
2044	$1,882.77	$3,490.34	$37.21	$77.40
2045	$1,890.58	$3,491.00	$37.21	$77.22
2046	$1,897.95	$3,490.37	$37.19	$77.01
2047	$1,904.86	$3,488.39	$37.16	$76.75
2048	$1,911.28	$3,485.02	$37.11	$76.46
2049	$1,917.21	$3,480.20	$37.05	$76.12
2050	$1,922.61	$3,473.88	$36.97	$75.75
2051	$1,961.06	$3,543.36	$37.71	$77.26
2052	$2,000.29	$3,614.23	$38.46	$78.81
2053	$2,040.29	$3,686.51	$39.23	$80.38
2054	$2,081.10	$3,760.24	$40.01	$81.99
2055	$2,122.72	$3,835.45	$40.81	$83.63

Table F-26: Storage Generic Information without transmission cost adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost				
	Capex ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)	
Year	**4 hr duration**	**10 hr duration**	**4 hr duration**	**10 hr duration**
2024	$1,739.08	$3,836.46	$43.48	$95.91
2025	$1,554.56	$3,418.32	$38.86	$85.46
2026	$1,534.36	$3,356.93	$38.36	$83.92
2027	$1,512.72	$3,291.56	$37.82	$82.29
2028	$1,489.60	$3,222.06	$37.24	$80.55
2029	$1,464.95	$3,148.25	$36.62	$78.71
2030	$1,438.71	$3,069.96	$35.97	$76.75
2031	$1,444.85	$3,078.42	$36.12	$76.96
2032	$1,450.66	$3,086.03	$36.27	$77.15
2033	$1,456.13	$3,092.74	$36.40	$77.32
2034	$1,461.23	$3,098.51	$36.53	$77.46
2035	$1,465.96	$3,103.32	$36.65	$77.58
2036	$1,470.30	$3,107.11	$36.76	$77.68
2037	$1,474.22	$3,109.86	$36.86	$77.75
2038	$1,477.71	$3,111.52	$36.94	$77.79
2039	$1,480.75	$3,112.04	$37.02	$77.80
2040	$1,483.33	$3,111.38	$37.08	$77.78
2041	$1,485.42	$3,109.51	$37.14	$77.74
2042	$1,487.00	$3,106.37	$37.17	$77.66
2043	$1,488.04	$3,101.92	$37.20	$77.55
2044	$1,488.54	$3,096.11	$37.21	$77.40
2045	$1,488.47	$3,088.89	$37.21	$77.22
2046	$1,487.79	$3,080.22	$37.19	$77.01
2047	$1,486.50	$3,070.04	$37.16	$76.75
2048	$1,484.56	$3,058.29	$37.11	$76.46
2049	$1,481.95	$3,044.94	$37.05	$76.12
2050	$1,478.65	$3,029.92	$36.97	$75.75
2051	$1,508.22	$3,090.52	$37.71	$77.26
2052	$1,538.39	$3,152.33	$38.46	$78.81
2053	$1,569.16	$3,215.38	$39.23	$80.38
2054	$1,600.54	$3,279.68	$40.01	$81.99
2055	$1,632.55	$3,345.28	$40.81	$83.63

Table F-27: High Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost - high sensitivity		
Capex with TRX ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	**4 hr duration**	**4 hr duration**
2024	$2,242.64	$49.43
2025	$2,258.87	$49.71
2026	$2,228.10	$48.80
2027	$2,195.20	$47.84
2028	$2,160.08	$46.82
2029	$2,122.69	$45.74
2030	$2,082.94	$44.60
2031	$2,112.14	$45.18
2032	$2,141.67	$45.77
2033	$2,171.54	$46.36
2034	$2,201.75	$46.96
2035	$2,232.30	$47.56
2036	$2,263.19	$48.17
2037	$2,294.42	$48.78
2038	$2,325.99	$49.40
2039	$2,357.92	$50.02
2040	$2,390.18	$50.65
2041	$2,422.80	$51.28
2042	$2,455.76	$51.92
2043	$2,489.07	$52.56
2044	$2,522.74	$53.21
2045	$2,556.75	$53.87
2046	$2,591.12	$54.52
2047	$2,625.83	$55.19
2048	$2,660.90	$55.85
2049	$2,696.32	$56.53
2050	$2,732.10	$57.20
2051	$2,786.74	$58.35
2052	$2,842.48	$59.51
2053	$2,899.33	$60.70
2054	$2,957.31	$61.92
2055	$3,016.46	$63.16

Table F-28: High Storage Generic Information without Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost - high sensitivity		
Capex with TRX ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,977.34	$49.43
2025	$1,988.27	$49.71
2026	$1,952.08	$48.80
2027	$1,913.66	$47.84
2028	$1,872.91	$46.82
2029	$1,829.78	$45.74
2030	$1,784.17	$44.60
2031	$1,807.39	$45.18
2032	$1,830.83	$45.77
2033	$1,854.48	$46.36
2034	$1,878.35	$46.96
2035	$1,902.43	$47.56
2036	$1,926.72	$48.17
2037	$1,951.22	$48.78
2038	$1,975.93	$49.40
2039	$2,000.85	$50.02
2040	$2,025.98	$50.65
2041	$2,051.31	$51.28
2042	$2,076.84	$51.92
2043	$2,102.58	$52.56
2044	$2,128.51	$53.21
2045	$2,154.64	$53.87
2046	$2,180.96	$54.52
2047	$2,207.48	$55.19
2048	$2,234.18	$55.85
2049	$2,261.07	$56.53
2050	$2,288.14	$57.20
2051	$2,333.90	$58.35
2052	$2,380.58	$59.51
2053	$2,428.19	$60.70
2054	$2,476.75	$61.92
2055	$2,526.29	$63.16

Table F-29: Low Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost - low sensitivity		
	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,550.82	$32.14
2025	$1,515.12	$31.11
2026	$1,491.54	$30.39
2027	$1,466.41	$29.62
2028	$1,439.68	$28.81
2029	$1,411.30	$27.96
2030	$1,381.22	$27.06
2031	$1,389.48	$27.12
2032	$1,397.53	$27.17
2033	$1,405.32	$27.21
2034	$1,412.88	$27.24
2035	$1,420.21	$27.26
2036	$1,427.22	$27.27
2037	$1,433.96	$27.27
2038	$1,440.40	$27.26
2039	$1,446.53	$27.24
2040	$1,452.30	$27.20
2041	$1,457.75	$27.16
2042	$1,462.86	$27.10
2043	$1,467.57	$27.03
2044	$1,471.85	$26.94
2045	$1,475.75	$26.84
2046	$1,479.21	$26.73
2047	$1,482.22	$26.60
2048	$1,484.73	$26.45
2049	$1,486.77	$26.29
2050	$1,488.34	$26.11
2051	$1,518.11	$26.63
2052	$1,548.47	$27.16
2053	$1,579.44	$27.71
2054	$1,611.03	$28.26
2055	$1,643.25	$28.83

Table F-30: Low Storage Generic Information without Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost - low sensitivity		
	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,285.51	$32.14
2025	$1,244.51	$31.11
2026	$1,215.52	$30.39
2027	$1,184.87	$29.62
2028	$1,152.51	$28.81
2029	$1,118.38	$27.96
2030	$1,082.45	$27.06
2031	$1,084.74	$27.12
2032	$1,086.68	$27.17
2033	$1,088.26	$27.21
2034	$1,089.48	$27.24
2035	$1,090.34	$27.26
2036	$1,090.75	$27.27
2037	$1,090.76	$27.27
2038	$1,090.34	$27.26
2039	$1,089.47	$27.24
2040	$1,088.10	$27.20
2041	$1,086.26	$27.16
2042	$1,083.95	$27.10
2043	$1,081.07	$27.03
2044	$1,077.63	$26.94
2045	$1,073.64	$26.84
2046	$1,069.06	$26.73
2047	$1,063.86	$26.60
2048	$1,058.01	$26.45
2049	$1,051.52	$26.29
2050	$1,044.38	$26.11
2051	$1,065.27	$26.63
2052	$1,086.57	$27.16
2053	$1,108.30	$27.71
2054	$1,130.47	$28.26
2055	$1,153.08	$28.83

Table F-31: Base Renewable Levelized Costs by In-Service Year with transmission cost

Levelized Costs by In-Service Year (30 year life) with Transmission Cost			
Year	Wind	Utility Scale Solar	Battery + Solar Hybrid
2024	$21.19	$47.81	$92.69
2025	$21.09	$47.12	$90.02
2026	$20.98	$46.38	$89.54
2027	$20.86	$45.59	$89.01
2028	$20.72	$44.75	$88.42
2029	$20.56	$43.86	$87.77
2030	$20.39	$42.91	$87.06
2031	$20.50	$41.90	$86.75
2032	$20.60	$40.84	$86.39
2033	$20.70	$39.71	$85.98
2034	$20.80	$38.51	$85.53
2035	$20.89	$37.25	$85.02
2036	$20.97	$37.36	$85.90
2037	$21.05	$37.46	$86.79
2038	$21.12	$37.54	$87.67
2039	$21.19	$37.61	$88.56
2040	$21.25	$37.68	$89.45
2041	$21.30	$37.72	$90.33
2042	$21.35	$37.75	$91.22
2043	$21.39	$37.77	$92.11
2044	$27.41	$43.18	$98.53
2045	$33.29	$48.53	$104.67
2046	$43.64	$58.24	$115.14
2047	$44.12	$58.63	$116.09
2048	$44.60	$59.01	$117.04
2049	$45.08	$59.39	$117.97
2050	$45.57	$59.75	$118.90
2051	$46.48	$60.77	$121.28
2052	$47.41	$61.79	$123.70
2053	$48.36	$62.81	$126.18
2054	$49.32	$63.83	$128.70
2055	$50.31	$64.85	$131.28

Table F-32: Base Renewable Levelized Costs by In-Service Year without Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost			
Year	Wind	Utility Scale Solar	Battery + Solar Hybrid
2024	$15.53	$38.56	$82.45
2025	$15.29	$37.65	$88.34
2026	$15.04	$36.69	$88.90
2027	$14.77	$35.67	$91.50
2028	$14.48	$34.59	$88.54
2029	$14.17	$33.45	$87.89
2030	$13.84	$32.25	$87.18
2031	$13.80	$30.98	$86.41
2032	$13.76	$29.64	$85.57
2033	$13.71	$28.22	$84.67
2034	$13.65	$26.73	$84.18
2035	$13.58	$25.16	$83.64
2036	$13.50	$25.00	$83.05
2037	$13.42	$24.83	$82.40
2038	$13.32	$24.63	$81.69
2039	$13.22	$24.42	$82.46
2040	$13.10	$24.18	$83.23
2041	$12.98	$23.93	$83.99
2042	$12.84	$23.65	$84.75
2043	$12.69	$23.35	$85.51
2044	$19.01	$29.03	$86.26
2045	$25.20	$34.68	$87.01
2046	$36.44	$45.40	$87.75
2047	$36.78	$45.53	$93.33
2048	$37.11	$45.65	$98.62
2049	$37.44	$45.76	$107.62
2050	$37.78	$45.85	$108.34
2051	$38.53	$46.87	$110.50
2052	$39.30	$47.89	$112.71
2053	$40.09	$48.91	$114.97
2054	$40.89	$49.93	$117.27
2055	$41.71	$50.95	$119.61

Table F-33: Low Renewable Levelized Costs by In-Service Year with Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$18.54	$44.27
2025	$17.62	$42.51
2026	$16.68	$40.69
2027	$15.73	$38.81
2028	$14.76	$36.88
2029	$13.78	$34.88
2030	$12.79	$32.81
2031	$12.67	$30.67
2032	$12.54	$28.47
2033	$12.40	$26.18
2034	$12.25	$23.82
2035	$12.09	$21.38
2036	$11.92	$21.42
2037	$11.73	$21.45
2038	$11.54	$21.48
2039	$11.33	$21.50
2040	$11.10	$21.51
2041	$10.87	$21.52
2042	$10.62	$21.52
2043	$10.36	$21.51
2044	$16.49	$27.45
2045	$22.49	$33.35
2046	$33.47	$44.22
2047	$33.67	$44.64
2048	$33.86	$45.06
2049	$34.05	$45.48
2050	$34.23	$45.90
2051	$34.92	$46.92
2052	$35.62	$47.94
2053	$36.33	$48.96
2054	$37.06	$49.98
2055	$37.80	$51.00

Table F-34: Low Renewable Levelized Costs by In-Service Year without Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$13.15	$35.34
2025	$12.18	$33.43
2026	$11.19	$31.46
2027	$10.19	$29.43
2028	$9.17	$27.33
2029	$8.13	$25.16
2030	$7.08	$22.92
2031	$6.84	$20.60
2032	$6.58	$18.21
2033	$6.32	$15.74
2034	$6.04	$13.17
2035	$5.74	$10.52
2036	$5.43	$10.33
2037	$5.11	$10.14
2038	$4.77	$9.93
2039	$4.42	$9.71
2040	$4.05	$9.48
2041	$3.66	$9.23
2042	$3.26	$8.98
2043	$2.83	$8.70
2044	$9.23	$14.90
2045	$15.51	$21.07
2046	$27.26	$32.85
2047	$27.34	$33.06
2048	$27.41	$33.27
2049	$27.48	$33.47
2050	$27.53	$33.67
2051	$28.08	$34.69
2052	$28.65	$35.71
2053	$29.22	$36.73
2054	$29.80	$37.75
2055	$30.40	$38.77

Table F-35: High Renewable Levelized Costs by In-Service Year with Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$22.22	$49.56
2025	$22.50	$49.81
2026	$22.79	$50.05
2027	$23.07	$50.29
2028	$23.37	$50.52
2029	$23.66	$50.74
2030	$23.96	$50.96
2031	$24.24	$51.18
2032	$24.52	$51.39
2033	$24.81	$51.60
2034	$25.09	$51.81
2035	$25.37	$52.02
2036	$25.66	$52.17
2037	$25.95	$52.30
2038	$26.24	$52.43
2039	$26.53	$52.53
2040	$26.82	$52.61
2041	$27.11	$52.68
2042	$27.41	$52.73
2043	$27.70	$52.75
2044	$33.68	$57.64
2045	$39.51	$62.46
2046	$49.44	$71.05
2047	$50.15	$71.39
2048	$50.86	$71.72
2049	$51.58	$72.04
2050	$52.32	$72.34
2051	$53.36	$73.36
2052	$54.43	$74.38
2053	$55.52	$75.40
2054	$56.63	$76.42
2055	$57.76	$77.44

Table F-36: High Renewable Levelized Costs by In-Service Year without transmission cost adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$16.26	$39.47
2025	$16.35	$39.49
2026	$16.43	$39.50
2027	$16.52	$39.50
2028	$16.60	$39.49
2029	$16.68	$39.46
2030	$16.76	$39.42
2031	$16.83	$39.36
2032	$16.91	$39.30
2033	$16.98	$39.22
2034	$17.04	$39.12
2035	$17.11	$39.01
2036	$17.17	$38.60
2037	$17.22	$38.16
2038	$17.27	$37.70
2039	$17.32	$37.21
2040	$17.36	$36.70
2041	$17.40	$36.17
2042	$17.43	$35.61
2043	$17.46	$35.02
2044	$23.72	$39.99
2045	$29.86	$44.95
2046	$40.76	$54.56
2047	$41.26	$54.40
2048	$41.75	$54.22
2049	$42.26	$54.03
2050	$42.76	$53.81
2051	$43.62	$54.83
2052	$44.49	$55.85
2053	$45.38	$56.87
2054	$46.29	$57.89
2055	$47.21	$58.91

Table F-37: Wind, Solar, Battery + Solar Hybrid Market Forecast-Adjusted LCOE with Transmission Cost

Edison Energy Market Forecast Adjusted LCOE			
Levelized Costs by In-Service Year (30 year life) with Transmission Cost			
Year	Wind	Solar	Battery + Solar Hybrid
2026	41.52	54.67	105.55
2027	36.24	51.73	101.00
2028	30.96	48.79	96.40
2029	25.68	45.85	91.76
2030	20.39	42.91	87.06

Table F-38: Wind, Solar, Battery + Solar Hybrid Market Forecast-Adjusted LCOE without Transmission Cost

Edison Energy Market Forecast Adjusted LCOE			
Levelized Costs by In-Service Year (30 year life) without Transmission Cost			
Year	Wind	Solar	Battery + Solar Hybrid
2028	21.64	37.71	88.77
2029	17.69	34.97	84.30
2030	13.84	32.25	79.78

V. Advanced Technology

The Company modeled three advanced technologies in this Resource Plan as discussed be below: small modular reactors, long-duration batteries, and hydrogen.

1. *Small Modular Reactors*

The small modular reactor (SMR) cost forecast uses the NREL 2023 ATB conservative projection and SMR operation parameter assumptions.

Table F-39: SMR Modeling Assumptions

SMR	
Representative Plan Size (MW)	600
Capacity Factor	92.7%
Book life (years)	60
PTC or ITC applied	ITC
Electric Transmission Delivery ($/kW)	250
Forced outage rate	7.3%

Table F-40: SMR LCOE with Transmission Cost

Levelized Costs by In-Service Year (30 year life) with Transmission Cost	
Year	SMR
2035	$105.26
2036	$107.36
2037	$109.51
2038	$111.70
2039	$113.93
2040	$116.21
2041	$118.53
2042	$120.90
2043	$123.32
2044	$133.16
2045	$142.50
2046	$157.12
2047	$160.26
2048	$163.46
2049	$166.73
2050	$170.06
2051	$173.46
2052	$176.93
2053	$180.47
2054	$184.08
2055	$187.76

2. *Long Duration Batteries*

Long duration batteries are modeled as those capable of discharging for 100 contiguous hours. Cost projections for long duration batteries are based on the 2030 cost projection detailed in the "Form Energy White Paper" in Great River Energy's 2023 - 2037 INTEGRATED RESOURCE PLAN, in Minnesota Public Utilities Commission Docket No. ET-2/RP-22-75 (March 31st, 2023) and assume a one percent cost decline trend. Operational parameters of the long duration batteries were developed based on information provided by Form Energy.

Table F-41: Long Duration Energy Storage Modeling Assumptions

Long Duration Energy Storage	
Representative Plan Size (MW)	100 MW
Battery Duration	100 hours
Capacity Factor	Subject to dispatch
Book life (years)	15
PTC or ITC applied	ITC
Electric Transmission Delivery ($/kW)	250

Table F-42: Long Duration 100 Hour Energy Storage Capital and Fixed O&M Cost Assumptions

Long Duration 100 hr Energy Storage		
Year	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
2030	$2,698.77	$19.00
2031	$2,728.27	$19.38
2032	$2,758.11	$19.77
2033	$2,788.31	$20.16
2034	$2,818.87	$20.57
2035	$2,849.80	$20.98
2036	$2,881.09	$21.40
2037	$2,912.76	$21.83
2038	$2,944.80	$22.26
2039	$2,977.23	$22.71
2040	$3,010.05	$23.16
2041	$3,043.26	$23.62
2042	$3,076.88	$24.10
2043	$3,110.90	$24.58
2044	$3,145.32	$25.07
2045	$3,180.17	$25.57
2046	$3,215.44	$26.08
2047	$3,251.13	$26.60
2048	$3,287.26	$27.14
2049	$3,323.83	$27.68
2050	$3,360.84	$28.23
2051	$3,398.31	$28.80
2052	$3,436.23	$29.37
2053	$3,474.61	$29.96
2054	$3,513.47	$30.56
2055	$3,552.81	$31.17

3. *Hydrogen*

Modeling assumptions for hydrogen production come from the S&P Global green hydrogen production cost forecast released in June 2023. We apply the IRA PTC

($3/kg) to hydrogen production costs, with the phase-out period starting in 2032 and ending in 2036. The EPRI US-REGEN model assumption is used for estimating the hydrogen delivery cost. An estimate of the additional capital investment needed, and timeline required to enable hydrogen blending capabilities for generic CTs was provided by GE.

Table F-43: Hydrogen Production Cost Assumption

Year	H2 Production Cost ($/mmBTU)	H2 Delivery Cost ($/mmBTU)	H2 PTC ($/mmBTU)	Overall H2 Fuel Cost ($/mmBTU)
2024	$ 38.72	$ 6.12	$ 22.67	$ 22.17
2025	$ 37.07	$ 6.24	$ 23.12	$ 20.19
2026	$ 34.50	$ 6.37	$ 23.58	$ 17.28
2027	$ 32.57	$ 6.49	$ 24.05	$ 15.01
2028	$ 31.73	$ 6.62	$ 24.54	$ 13.82
2029	$ 30.98	$ 6.76	$ 25.03	$ 12.71
2030	$ 30.23	$ 6.89	$ 25.53	$ 11.60
2031	$ 29.56	$ 7.03	$ 26.04	$ 10.55
2032	$ 28.96	$ 7.17	$ 26.56	$ 9.57
2033	$ 28.41	$ 7.31	$ 27.09	$ 8.63
2034	$ 27.93	$ 7.46	$ 27.63	$ 7.76
2035	$ 27.49	$ 7.61	$ 28.18	$ 6.92
2036	$ 27.08	$ 7.76	$ 28.75	$ 6.10
2037	$ 26.66	$ 7.92	$ 29.32	$ 5.25
2038	$ 25.25	$ 8.08	$ 29.91	$ 3.42
2039	$ 24.98	$ 8.24	$ 30.51	$ 2.71
2040	$ 24.74	$ 8.40	$ 31.12	$ 2.02
2041	$ 24.61	$ 8.57	$ 31.74	$ 1.44
2042	$ 24.50	$ 8.74	$ 32.37	$ 0.87
2043	$ 24.47	$ 8.92	$ 33.02	$ 0.37
2044	$ 24.47	$ 9.09	$ 33.68	$ (0.12)
2045	$ 24.50	$ 9.28	$ 34.36	$ (0.58)
2046	$ 24.54	$ 9.46	$ -	$ 34.00
2047	$ 24.63	$ 9.65	$ -	$ 34.28
2048	$ 24.74	$ 9.84	$ -	$ 34.59
2049	$ 24.86	$ 10.04	$ -	$ 34.90
2050	$ 25.04	$ 10.24	$ -	$ 35.28
2051	$ 25.54	$ 10.45	$ -	$ 35.99
2052	$ 26.05	$ 10.66	$ -	$ 36.71
2053	$ 26.58	$ 10.87	$ -	$ 37.44
2054	$ 27.11	$ 11.09	$ -	$ 38.19
2055	$ 27.65	$ 11.31	$ -	$ 38.96

W. Market Purchases and Sales Import/Export Limits and Carbon Rate

In order to account for emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed based on MISO's MTEP21 Future 2 modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

Table F-44: Market Purchase Carbon Rate

Market Purchase CO2 Rate																
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
lbs/MWh	1119	1029	938	848	758	668	578	560	542	524	506	489	481	463	446	428
	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
lbs/MWh	452	424	414	403	393	383	373	362	352	342	331	321	311	301	290	280

ATTACHMENT A: HEAT RATE UPDATED

In Docket No. E999/CI-06-159 (In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005), the Minnesota Commission required the Company to file information on the fossil fuel efficiency (heat rate) of our generation units, and actions we are taking to increase the fuel efficiency of those units.

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2022 in Table F-45 below.

Table F-45: 2022 FERC Heat Rates

Unit	Heat Rate
A.S. King	15,223
Sherco	10,235
Monticello	10,244
Prairie Island	10,675
Black Dog (NG)	11,436
High Bridge	7,940
Riverside	7,116
French Island	24,327
Wilmarth	22,659

The Company's Performance Optimization department performs online heat rate and performance analysis. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted as needed. These tools factor into our assessment of the condition of these individual components, as well as how their respective performance levels will impact the overall efficiency of a given generating unit. Table F-46 below shows a summary of NSP System heat rate testing from 2016-2023.

Table F-46: Heat Rate Tests – 2016-2023

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Sherco U1	Coal Boiler	Performance	2019
King U1	Coal Boiler	Performance	2019
Sherco U2	Coal Boiler	Performance	2016
Black Dog U5/U2	Combined Cycle	Performance	2021
High Bridge CC	Combined Cycle	Heat Rate	2018
Sherco U3	Coal Boiler	Heat Rate	2017
Black Dog U6	Combustion Turbine	Heat Rate	2018
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2018

As part of its heat rate testing and reporting protocol, the Performance Optimization group identifies potential heat rate improvement opportunities and validates actual performance enhancements. The Company does not look at heat rate improvements in isolation when considering plant improvement projects; rather, we perform a collective assessment of potential safety, efficiency, and environmental performance improvements as well as overall economics in developing our generation asset management objectives. Looking forward, the Company plans to continue our proactive cycle of performance monitoring and testing, heat rate curve updates, and overall unit assessments at our generation units and implement improvements as opportunities arise.

ATTACHMENT B: WATER AND PLANT OPERATIONS

The Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings in Docket No. E002/RP-10-825 suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 4).

The Company's generating units are geographically positioned along major Minnesota waterways. The access to water accommodates the thermal needs of these generating units. As such, the Company's plant operations are governed by and comply with all applicable cooling water intake and discharge rules and regulations, which may indirectly affect EnCompass modeling as discussed below.

The Clean Water Act Section 316(a) sets thermal limitations for discharges and the criteria and processes for allowing thermal variances. The Company's power plant discharge temperature limits and allowances for thermal emergency provisions are outlined in the plants' National Pollutant Discharge Elimination System (NPDES) permits. Additionally, Xcel Energy has policies which outline the conditions and procedures to implement during periods of energy emergencies that provide a temporary pathway for enforcement discretion for thermal discharge compliance if Xcel Energy has taken the prescribed actions and coordinates with the Minnesota Pollution Control Agency before, during, and post an actual energy emergency. Xcel Energy is not granted authority to exceed our thermal discharge limits by our permit conditions at any time by our NPDES permit conditions.

Section 316(b) of the Clean Water Act governs the design and operation of intake structures in order to minimize adverse environmental impacts to aquatic life. EPA issued new rules in August 2014 that impacts all plants that withdraw water for cooling purposes. The rules require improvements to intake screening technology to minimize the number of aquatic organisms that are killed due to being stuck to the screens (referred to as "impingement). The rules also created a process for the state permitting agency to evaluate and determine if additional improvements are required to minimize the number of smaller organisms that pass through the intake screens and enter the plant cooling water system (referred to as "entrainment"). While the costs associated with the impingement compliance requirements are definable, the costs associated with the entrainment compliance requirements are uncertain and are determined by the permitting agency just prior to any planned capital improvements to each plant.

Timing of the compliance requirements is site-specific and is determined by each site's NPDES permit renewal timeline.

While specific conditions, such as the effects of drought, are not directly modeled in EnCompass, the model reflects the impact of reducing plant output to comply with each site's NPDES permit thermal discharge limits. Modeling in EnCompass includes two methods to account for impacts due to changes in plant operations: each resource is modeled using a unit specific median accredited capacity rating, and the system needs are modeled with a planning reserve margin. By modeling the system needs with a planning reserve margin, the base level of required resources is assumed to be higher than those needed to meet the forecasted peak system demand. By modeling all units with an assumed level of forced outage, the base level of all available resources, modeled in aggregate, is assumed to be sufficient to represent resource availability due to emergency changes in plant operations. Thus, the impact of reducing plant output due to drought conditions and/or plant thermal discharge limitations is reflected through corrections to both obligation and resource adjustments.

ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following tables shows load and resources using Installed Capacity Rating (ICAP) for the planning period for each season, in compliance with the Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings.[28]

Table F-47: Load and Resources Tables, 2024-2040 Planning Period, Summer Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO Planning Reserve Margin (ICAP)	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Obligation (Summer)	**11,073**	**11,212**	**11,706**	**12,136**	**12,371**	**12,527**	**12,753**	**12,994**	**13,337**	**13,621**	**14,009**	**14,373**	**14,708**	**14,932**	**15,171**	**15,405**	**15,539**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	1,020	1,034	1,048	1,057	1,062	1,066	1,067	1,069	1,070	1,071	1,073	1,020	1,020	1,020	1,020	1,020	1,020
Coal	1,697	1,697	1,697	1,019	1,019	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,657	1,657	1,657	1,657	1,657	1,657	1,657	1,657	1,657	1,657	1,136	617	617	617	617	617	617
Natural Gas/Oil	3,975	3,670	3,925	3,925	3,396	3,094	2,842	2,724	2,442	2,442	2,442	2,442	2,442	2,442	2,442	2,133	2,133
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	803	303	301	301	301	301	301	301	184	180	151	134	124	120	120	120	120
Wind	4,520	4,310	4,321	4,310	4,261	4,094	4,067	3,984	3,960	3,338	3,313	3,313	3,033	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,351	2,138	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,631	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	153	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,185**	**15,906**	**17,539**	**17,037**	**16,602**	**15,772**	**15,629**	**15,047**	**14,721**	**14,187**	**13,706**	**13,185**	**12,884**	**12,873**	**13,013**	**12,796**	**12,782**
Summer Existing & Approved Net Resource (Need)/Surplus	**5,112**	**4,694**	**5,833**	**4,901**	**4,231**	**3,245**	**2,876**	**2,053**	**1,384**	**566**	**(303)**	**(1,188)**	**(1,823)**	**(2,059)**	**(2,158)**	**(2,609)**	**(2,757)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	231	234	236	238	239	239	238	238	237	236	236	235	235	234	234	233	233
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	18	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**363**	**586**	**832**	**1,133**	**1,542**	**1,905**	**2,234**	**2,430**	**2,619**	**2,815**	**3,068**	**3,256**	**3,339**	**3,402**	**3,479**	**3,566**	**3,717**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**5,475**	**5,279**	**6,665**	**6,034**	**5,772**	**5,150**	**5,110**	**4,483**	**4,003**	**3,382**	**2,765**	**2,068**	**1,516**	**1,343**	**1,321**	**957**	**960**
Reference Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	100	500	700	700	1,600	1,600	2,400	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	480	480	600	600	780	960	960	960	960	1,440	1,920	2,220	2,220	2,220
Firm Dispatchable	0	0	0	748	1,496	1,496	2,244	2,244	2,618	2,992	2,992	3,740	3,740	3,740	3,740	4,488	4,488
Wind	0	0	0	400	2,200	2,600	2,600	3,800	4,600	5,000	6,600	7,600	8,200	8,600	9,000	9,600	11,000
Reference Plan Resource Adjustments	**0**	**0**	**0**	**1,628**	**4,176**	**4,796**	**5,944**	**7,524**	**8,878**	**10,552**	**12,152**	**14,700**	**15,780**	**16,660**	**17,360**	**18,708**	**20,108**
Reference Plan Net Resource (Need)/Surplus	**5,475**	**5,279**	**6,665**	**7,662**	**9,949**	**9,946**	**11,054**	**12,007**	**12,881**	**13,934**	**14,918**	**16,768**	**17,296**	**18,003**	**18,681**	**19,665**	**21,068**

[28] *See* Docket No. E002/RP-10-825. In addition to noting amendments to Minn. Stat. § 216B.2422, subd. 4, the Notice suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 2).

Table F-48: Load and Resources Tables, 2024-2040 Planning Period, Fall Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO Planning Reserve Margin (ICAP)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Obligation (Fall)	**9,425**	**9,556**	**9,999**	**10,390**	**10,545**	**10,692**	**10,879**	**11,080**	**11,343**	**11,625**	**11,974**	**12,315**	**12,562**	**12,793**	**12,987**	**13,168**	**13,291**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	734	747	759	767	772	776	779	781	784	787	790	1,020	1,020	1,020	1,020	1,020	1,020
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,165	632	632	632	632	632	632
Natural Gas/Oil	4,363	4,268	4,268	4,268	3,383	3,383	3,053	2,913	2,624	2,624	2,624	2,624	2,624	2,624	2,624	2,289	2,289
Storage	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	803	301	301	301	301	301	301	301	184	180	151	134	124	120	120	120	120
Wind	4,520	4,310	4,321	4,310	4,257	4,094	4,067	3,974	3,755	3,338	3,313	3,112	3,033	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,351	2,138	3,487	3,671	3,814	3,956	4,095	4,236	4,336	4,432	4,529	4,627	4,631	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	154	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,336**	**16,274**	**17,642**	**17,138**	**16,343**	**15,812**	**15,591**	**14,980**	**14,452**	**14,126**	**13,634**	**13,171**	**13,081**	**13,070**	**13,210**	**12,967**	**12,953**
Fall Existing & Approved Net Resource (Need)/Surplus	**6,911**	**6,718**	**7,642**	**6,748**	**5,798**	**5,119**	**4,712**	**3,900**	**3,110**	**2,501**	**1,660**	**856**	**519**	**277**	**223**	**(201)**	**(338)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	143	146	148	149	150	150	150	150	150	150	150	150	150	150	150	150	150
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	18	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**277**	**501**	**748**	**1,050**	**1,460**	**1,826**	**2,156**	**2,354**	**2,544**	**2,742**	**2,996**	**3,184**	**3,268**	**3,331**	**3,409**	**3,495**	**3,646**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**7,188**	**7,218**	**8,390**	**7,798**	**7,259**	**6,945**	**6,868**	**6,254**	**5,654**	**5,243**	**4,656**	**4,041**	**3,787**	**3,607**	**3,632**	**3,294**	**3,308**
Reference Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	100	500	700	700	1,600	1,600	2,400	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	480	480	600	600	780	960	960	960	960	1,440	1,920	2,220	2,220	2,220
Firm Dispatchable	0	0	0	748	1,496	1,496	2,244	2,244	2,618	2,992	2,992	3,740	3,740	3,740	3,740	4,488	4,488
Wind	0	0	0	400	2,200	2,600	2,600	3,800	4,600	5,000	6,600	7,600	8,200	8,600	9,000	9,600	11,000
Reference Plan Resource Adjustments	**0**	**0**	**0**	**1,628**	**4,176**	**4,796**	**5,944**	**7,524**	**8,878**	**10,552**	**12,152**	**14,700**	**15,780**	**16,660**	**17,360**	**18,708**	**20,108**
Reference Plan Net Resource (Need)/Surplus	**7,188**	**7,218**	**8,390**	**9,426**	**11,435**	**11,741**	**12,812**	**13,778**	**14,532**	**15,795**	**16,808**	**18,741**	**19,567**	**20,267**	**20,992**	**22,002**	**23,416**

Table F-49: Load and Resources Tables, 2024-2040 Planning Period, Winter Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO Planning Reserve Margin (ICAP)	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%
Obligation (Winter)	**9,879**	**10,293**	**10,794**	**11,022**	**11,243**	**11,348**	**11,578**	**11,822**	**12,170**	**12,591**	**12,910**	**13,295**	**13,586**	**14,032**	**14,290**	**14,620**	**14,534**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	367	379	390	401	406	411	416	421	427	432	437	1,020	1,020	1,020	1,020	1,020	1,020
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646
Natural Gas/Oil	4,687	4,617	4,478	4,478	4,244	3,538	3,538	3,031	3,031	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,372
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	753	753	301	301	301	301	301	301	184	184	151	137	124	124	120	120	120
Wind	4,520	4,312	4,485	4,310	4,273	4,094	4,088	4,023	3,960	3,349	3,337	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,315	1,968	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	171	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,265**	**16,568**	**17,687**	**17,023**	**16,895**	**15,642**	**15,776**	**14,828**	**14,748**	**13,934**	**13,441**	**13,508**	**13,578**	**13,197**	**13,333**	**13,425**	**13,050**
Winter Existing & Approved Net Resource (Need)/Surplus	**6,386**	**6,275**	**6,893**	**6,001**	**5,652**	**4,293**	**4,199**	**3,005**	**2,577**	**1,343**	**531**	**214**	**(8)**	**(835)**	**(956)**	**(1,195)**	**(1,484)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	41	43	45	47	48	48	49	50	51	52	53	54	55	56	57	57	58
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**171**	**424**	**683**	**998**	**1,420**	**1,797**	**2,138**	**2,346**	**2,547**	**2,754**	**3,017**	**3,214**	**3,295**	**3,357**	**3,434**	**3,517**	**3,665**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**6,557**	**6,699**	**7,576**	**6,999**	**7,072**	**6,090**	**6,336**	**5,351**	**5,124**	**4,098**	**3,548**	**3,428**	**3,287**	**2,523**	**2,478**	**2,322**	**2,181**
Reference Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	100	500	700	700	1,600	1,600	2,400	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	480	480	600	600	780	960	960	960	960	1,440	1,920	2,220	2,220	2,220
Firm Dispatchable	0	0	0	748	1,496	1,496	2,244	2,244	2,618	2,992	2,992	3,740	3,740	3,740	3,740	4,488	4,488
Wind	0	0	0	400	2,200	2,600	2,600	3,800	4,600	5,000	6,600	7,600	8,200	8,600	9,000	9,600	11,000
Reference Plan Resource Adjustments	**0**	**0**	**0**	**1,628**	**4,176**	**4,796**	**5,944**	**7,524**	**8,878**	**10,552**	**12,152**	**14,700**	**15,780**	**16,660**	**17,360**	**18,708**	**20,108**
Reference Plan Net Resource (Need)/Surplus	**6,557**	**6,699**	**7,576**	**8,627**	**11,248**	**10,886**	**12,280**	**12,875**	**14,002**	**14,650**	**15,700**	**18,129**	**19,067**	**19,183**	**19,838**	**21,030**	**22,289**

Table F-50: Load and Resources Tables, 2024-2040 Planning Period, Spring Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO Planning Reserve Margin (ICAP)	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
Obligation (Spring)	**9,916**	**10,058**	**10,560**	**10,994**	**11,201**	**11,289**	**11,487**	**11,707**	**11,974**	**12,220**	**12,564**	**12,933**	**13,241**	**13,484**	**13,662**	**13,879**	**13,965**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	683	696	709	719	725	729	733	737	741	745	749	1,020	1,020	1,020	1,020	1,020	1,020
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,165	632	632	632	632	632	632
Natural Gas/Oil	4,363	4,363	4,268	4,268	4,042	3,383	3,383	2,913	2,913	2,624	2,624	2,624	2,624	2,624	2,624	2,624	2,289
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	803	803	301	301	301	301	301	301	184	184	151	134	124	120	120	120	120
Wind	4,520	4,310	4,325	4,310	4,262	4,094	4,088	3,984	3,960	3,338	3,313	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,351	2,138	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	166	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,297**	**16,810**	**17,596**	**17,090**	**16,961**	**15,765**	**15,898**	**14,945**	**14,904**	**14,088**	**13,593**	**13,382**	**13,455**	**13,070**	**13,210**	**13,302**	**12,953**
Spring Existing & Approved Net Resource (Need)/Surplus	**6,381**	**6,752**	**7,036**	**6,096**	**5,761**	**4,476**	**4,411**	**3,239**	**2,930**	**1,868**	**1,030**	**449**	**214**	**(415)**	**(452)**	**(577)**	**(1,012)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	136	138	140	142	143	144	144	144	145	145	145	146	146	146	147	147	148
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	18	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**278**	**508**	**763**	**1,073**	**1,491**	**1,864**	**2,200**	**2,405**	**2,603**	**2,807**	**3,068**	**3,263**	**3,345**	**3,407**	**3,484**	**3,568**	**3,717**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**6,659**	**7,260**	**7,799**	**7,169**	**7,252**	**6,340**	**6,612**	**5,644**	**5,533**	**4,674**	**4,097**	**3,713**	**3,559**	**2,992**	**3,032**	**2,991**	**2,705**
Reference Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	100	500	700	700	1,600	1,600	2,400	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	480	480	600	600	780	960	960	960	960	1,440	1,920	2,220	2,220	2,220
Firm Dispatchable	0	0	0	748	1,496	1,496	2,244	2,244	2,618	2,992	2,992	3,740	3,740	3,740	3,740	4,488	4,488
Wind	0	0	0	400	2,200	2,600	2,600	3,800	4,600	5,000	6,600	7,600	8,200	8,600	9,000	9,600	11,000
Reference Plan Resource Adjustments	**0**	**0**	**0**	**1,628**	**4,176**	**4,796**	**5,944**	**7,524**	**8,878**	**10,552**	**12,152**	**14,700**	**15,780**	**16,660**	**17,360**	**18,708**	**20,108**
Reference Plan Net Resource (Need)/Surplus	**6,659**	**7,260**	**7,799**	**8,797**	**11,428**	**11,136**	**12,556**	**13,168**	**14,411**	**15,227**	**16,249**	**18,413**	**19,339**	**19,653**	**20,392**	**21,699**	**22,814**

APPENDIX G: SCENARIO SENSITIVITY ANALYSIS: PVRR & PVSC SUMMARY

NPV ($m) 2024-2040

	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$51,037	$34,678	$52,373	$46,682	$56,185	$48,909	$52,049	$49,435	$51,621	$59,243	$47,395	$68,735	$55,329	$47,871	$54,853	$50,683	$57,941	$45,679	$50,703	$34,819
Scenario 2	$50,624	$34,581	$51,900	$46,281	$55,618	$48,611	$51,447	$49,303	$51,279	$58,537	$47,052	$68,128	$54,901	$47,570	$54,258	$50,288	$57,712	$45,559	$50,406	$34,619
Scenario 3	$50,252	$34,215	$51,516	$45,923	$55,348	$48,375	$51,095	$48,920	$50,913	$58,084	$46,655	$67,761	$54,529	$47,204	$53,896	$49,902	$57,304	$45,218	$50,041	$34,207

NPV ($m) 2024-2047

	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$63,635	$44,948	$65,112	$59,034	$71,674	$60,616	$65,543	$60,627	$64,373	$72,700	$59,742	$84,553	$69,086	$60,433	$69,807	$63,273	$75,761	$55,450	$62,974	$46,314
Scenario 2	$63,198	$45,239	$64,537	$58,689	$71,125	$60,472	$64,806	$60,662	$64,030	$71,694	$59,518	$83,659	$68,622	$60,241	$68,978	$62,855	$75,464	$55,562	$62,589	$45,991
Scenario 3	$62,695	$44,994	$63,973	$58,249	$70,720	$60,056	$64,248	$60,265	$63,536	$70,946	$58,952	$82,987	$68,104	$59,821	$68,310	$62,339	$74,686	$55,228	$62,042	$45,373

NPV ($m) 2024-2050

	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$68,788	$48,927	$70,352	$64,038	$78,299	$65,403	$71,005	$65,289	$69,567	$78,268	$64,739	$91,077	$74,695	$65,496	$75,914	$68,415	$83,315	$59,292	$70,930	$54,273
Scenario 2	$68,275	$49,317	$69,670	$63,648	$77,703	$65,275	$70,150	$65,315	$69,158	$77,029	$64,491	$90,010	$74,150	$65,287	$74,942	$67,925	$82,947	$59,387	$69,927	$53,326
Scenario 3	$67,762	$49,166	$69,080	$63,219	$77,286	$64,776	$69,559	$64,942	$68,656	$76,210	$63,916	$89,263	$73,620	$64,889	$74,217	$67,401	$82,041	$59,083	$69,080	$52,407

NPV ($m) 2024-2040

DELTA	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	($413)	($97)	($473)	($400)	($567)	($298)	($601)	($132)	($342)	($707)	($343)	($607)	($428)	($301)	($595)	($396)	($230)	($120)	($298)	($200)
Scenario 3	($785)	($464)	($856)	($758)	($837)	($534)	($954)	($514)	($708)	($1,160)	($739)	($974)	($800)	($667)	($957)	($781)	($638)	($461)	($662)	($612)

NPV ($m) 2024-2047

DELTA	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	($437)	$291	($575)	($345)	($548)	($143)	($737)	$35	($343)	($1,006)	($224)	($894)	($463)	($192)	($829)	($419)	($297)	$112	($385)	($323)
Scenario 3	($941)	$46	($1,139)	($785)	($953)	($560)	($1,294)	($362)	($837)	($1,754)	($790)	($1,565)	($982)	($612)	($1,497)	($934)	($1,075)	($222)	($931)	($941)

NPV ($m) 2024-2050

DELTA	PVSC	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	High Tech Cost	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	0 Reg Mid SC-GHG	0 Reg Low SC-GHG	Mkt Off	Environ Policies	High Tech + High Load	Low Tech + Low Load	Carbon Free - PVSC	Carbon Free - PVRR
Scenario 1	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	($513)	$391	($681)	($390)	($596)	($128)	($855)	$26	($409)	($1,239)	($248)	($1,067)	($544)	($209)	($972)	($490)	($368)	$95	($1,003)	($947)
Scenario 3	($1,025)	$239	($1,272)	($819)	($1,013)	($627)	($1,446)	($347)	($911)	($2,058)	($823)	($1,814)	($1,074)	($607)	($1,697)	($1,014)	($1,273)	($209)	($1,850)	($1,865)

APPENDIX G: SCENARIO SENSITIVITY ANALYSIS: PVRR & PVSC SUMMARY

NPV ($m) 2024-2040

			B	C															Carbon Free	Carbon Free - PVRR
	PVSC	**PVRR**	**52372.82408**	**46681.52128**	**Low Load**	**High Load**	**Low Resource Cost**	**High Resource Cost**	**Low Externality**	**59243.3568**	**47394.61049**	**68734.93935**	**55328.98018**	**47871.48993**	**High Load High Gas/Coal/ Mkts Low Resource Cost**	**Low Load Low Gas/Coal/Mkts Low Resource Cost**			50703.399	34818.623
Scenario 1	$51,037	$34,678	$51,900	$46,281	$46,328	$49,952	$44,760	$46,813	$40,949	$58,537	$47,052	$68,128	$54,901	$47,570	$49,797	$45,359			50405.716	34619.049
Scenario 2	$34,678	$37,495	$51,516	$45,923	$46,258	$49,795	$44,703	$46,499	$40,570	$58,084	$46,655	$67,761	$54,529	$47,204	$49,787	$45,276			50041.16	34206.581
Scenario 3	$45,563	$37,662	$45,018	$46,420	$46,373	$49,940	$44,828	$46,593	$40,643	$38,975	$42,418	$51,868	$37,235	$44,993	$49,935	$45,396				
																			Carbon Free	Carbon Free - PVRR
			65111.68638	59033.6772						72699.81835	59742.1552	84552.92726	69085.81243	60432.5742					62973.604	46313.848
			64536.73403	58688.66102						71693.89084	59517.90803	83658.68946	68622.33833	60240.52433					62588.761	45991.288
NPV ($m) 2024-2047			**63972.99985**	**58249.10305**						**70945.80894**	**58951.83002**	**82987.44469**	**68103.96931**	**59820.80352**					62042.215	45373.171
			B	C																
	PVSC	**PVRR**	**High Fuel/Mkt Price**	**High Gas/Coal/ Mkts**	**Low Load**	**High Load**	**Low Resource Cost**	**High Resource Cost**	**Low Externality**	**Low Externality, Low Regulatory**	**Mid Externality, Mid Regulatory**	**High Externality**	**No Reg or Externality Costs**	**Market sales off**	**High Load High Gas/Coal/ Mkts Low Resource Cost**	**Low Load Low Gas/Coal/Mkts Low Resource Cost**			Carbon Free	Carbon Free - PVRR
Scenario 1	$51,037	$34,678	$70,352	$64,038	$46,328	$49,952	$44,760	$46,813	$40,949	$78,268	$64,739	$91,077	$74,695	$65,496	$49,797	$45,359			70930.327	54272.774
Scenario 2	$34,678	$37,495	$69,670	$63,648	$46,258	$49,795	$44,703	$46,499	$40,570	$77,029	$64,491	$90,010	$74,150	$65,287	$49,787	$45,276			69927.29	53325.749
Scenario 3	$45,563	$37,662	$69,080	$63,219	$46,373	$49,940	$44,828	$46,593	$40,643	$76,210	$63,916	$89,263	$73,620	$64,889	$49,935	$45,396			69079.946	52407.373

																			Carbon Free	Carbon Free - PVRR
NPV ($m) 2024-2050																				
			B	C															-297.68355	-199.57344
	PVSC	**PVRR**	**High Fuel/Mkt Price**	**High Gas/Coal/ Mkts**	**Low Load**	**High Load**	**Low Resource Cost**	**High Resource Cost**	**Low Externality**	**Low Externality, Low Regulatory**	**Mid Externality, Mid Regulatory**	**High Externality**	**No Reg or Externality Costs**	**Market sales off**	**High Load High Gas/Coal/ Mkts Low Resource Cost**	**Low Load Low Gas/Coal/Mkts Low Resource Cost**				
Scenario 1	51036.59026	34678.04172	45215.8322	46359.70261	46328.46081	49951.59724	44759.56228	46813.2613	40948.6664	39008.09178	42541.44966	52889.73956	37276.22999	45260.30446	near	45359.21943				

NPV ($m) 2024-2047

																			Carbon Free	Carbon Free - PVRR
Scenario 3	$45,563	$37,662	$45,018	$46,420	$46,373	$49,940	$44,828	$46,593	$40,643	$38,975	$42,418	$51,868	$37,235	$44,993	$49,935	$45,396				

																			Carbon Free	Carbon Free - PVRR
										($1,239)	($248)									
										($2,058)										

APPENDIX H – RESOURCE OPTIONS

I. INTRODUCTION

Our planning horizon spans from 2024 to 2040, during which customer peak demand is projected to rise from 9,400 MW to over 13,200 MW, before Demand Side Management (DSM) adjustments. With our existing and approved resources, we face a capacity deficiency in the late-2020s due to resource retirements and contract expirations. We have identified a portfolio of resources that addresses not only our projected capacity shortfall but also aligns with our core principles of cost-effectiveness, reliability, environmental stewardship and risk mitigation.

The next section delves into our existing resources, offering a comprehensive look at our current system capacity and future system plans thus setting the stage for a deeper discussion on bridging the gap between current capabilities and future resource needs.

II. EXISTING RESOURCES

The Company currently owns and has under contract approximately 15,000 MW of capacity plus 211 MW of distributed solar, although as stated above, many of our current resources are slated to retire over the current planning period. Below, we include discussion of each resource type, and tables showing each generating unit, whether it is owned or contracted, the capacity we own or contract,[1] and the retirement year if known, as reflected in the EnCompass model. These numbers have been rounded to the nearest whole number for simplicity, where applicable.

A. Coal

The Company owns and operates three coal-fired generating units at two sites. The Sherburne County Generation Station (Sherco) previously had three operating units. On December 31, 2023, we reached an exciting milestone in the clean energy transition with the retirement of Sherco Unit 2. The closing of Sherco 2 resulted in a loss of 682 MW of firm dispatchable generation from the NSP system. We are planning to retire Sherco 1 and 3 by December 31, 2026 and 2030, respectively. We are planning to retire the Allen S. King plant in 2028. Retirements of these plants will result in the loss of an additional 1,705 MW of firm dispatchable generation from the NSP system.

[1] Expected as of January 2024.

Table H-1: Existing Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Maximum Capacity (MW)	Existing Retirement/Contract Expiration
Allen S King[2]	Steam Turbine (ST)	Own	510	2028
Sherco 1	ST	Own	678	2026
Sherco 2	ST	Own	682	Closed as of 2023
Sherco 3[3]	ST	Own	517	2030

B. Nuclear

The Company owns and operates three nuclear units – two units at Prairie Island Nuclear Generating Plant and one at Monticello Nuclear Generating Plant – with a total net capacity of approximately 1,650 MW. These units operate at high-capacity factors and provide nearly 30 percent of the total electric energy and approximately 40 percent of the carbon-free energy our customers consume. Between 2019 and 2023, we have consistently maintained production costs at $31.25 per megawatt-hour (MWh) or less, which is a decrease of more than 20 percent when compared to 2013 production costs. In this plan, we are seeking to extend both nuclear facilities to meet future capacity needs beyond their existing retirement dates.

Table H-2: Existing Nuclear Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Monticello	Boiling Water Reactor	Own	617	2040
Prairie Island 1	Pressurized Water Reactor (PWR)	Own	521	2033
Prairie Island 2	PWR	Own	519	2034

**Net summer capacity shown.*

[2] Asset is in seasonal operation now. Capacity represented above is maximum capacity offered during one of the seasons – winter – in which it operates.
[3] This represents the portion of Sherco 3 under our ownership.

C. Natural Gas and Oil

The Company owns or contracts for several natural gas and oil facilities. Our current natural gas and oil generators are configured as either simple-cycle Combustion Turbines (CTs), Combined Cycle Gas Turbine (CCs) or reciprocating internal combustion engines (RICE). The CTs are located at seven different sites and provide peaking capacity, meaning they are typically only dispatched a limited number of times a year during peak demand and/or net load conditions. The CCs are located at five sites and provide intermediate capacity, meaning they tend to operate at higher capacity factors due to better efficiencies and lower dispatch prices when compared to CTs. RICE units are located at existing CT sites. Our current natural gas and oil fleet provides nearly 4,726 MW of firm dispatchable capacity.

Table H-3: Existing Natural Gas and Oil Resources

Name of Unit(s)	Type	Owned or Contracted (PPA)	Maximum Capacity (MW)	Existing or Planned Retirement/Contract Expiration
Black Dog 5/2	CC	Own	298	2032
High Bridge	CC	Own	580	2048
Riverside	CC	Own	508	2049
Mankato Energy Center	CC	PPA	711	2028, 2039
Cottage Grove	CC	PPA	245	2027
Angus Anson 2-4	CT	Own	386	2041, 2045
Angus Anson RICE	IC	Own	28	2068
Black Dog 6	CT	Own	228	2058
Blue Lake 7,8	CT	Own	350	2045
Inver Hills 1-6	CT	Own	345	2030
Wheaton [4]	CT	Own	225	2065
Wheaton Recip	IC	Own	45	2065
Cannon Falls Energy Center	CT	PPA	356	2028
Blue Lake 1-4	CT (Oil)	Own	192	2025
French Island 3,4	CT (Oil)	Own	159	2030
Wheaton 6	CT (Oil)	Own	70	2024

D. Biomass

The company owns or contracts for various biomass facilities. Refuse-derived fuel (RDF), landfill (LND,) and digester (DIGT) resources are also generally considered biomass resources and therefore included in this category. These facilities total nearly 134 MW of capacity and are located at six sites on our system. More about the Company's RDF plants can be found in Appendix W: RDF Plants.

[4] Capacity and retirement date shown for repowered asset, pending approval before the Wisconsin Public Utilities Commission.

Table H-4: Existing Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Maximum Capacity (MW)	Retirement/Contract Expiration
Bayfront 5,6	Bio	Own	26	2035
French Island 1,2	Bio	Own	15	2027
Red Wing 1,2	Bio	Own	18	2027
Wilmarth 1,2	Bio	Own	17	2027
St. Paul Cogen	Bio	PPA	24	2024
Hennepin Energy Recovery Center	RDF	PPA	34	2024

E. Hydroelectric

The Company owns or contracts for hydropower resources with a number of different counterparties, totaling nearly 800 MW of capacity. The majority of our current hydro capacity is provided by our PPAs with Manitoba Hydro, which expire in 2025. While the Company is considering contract renewals with Manitoba Hydro, they are not included here as they are not finalized at the time of final modeling.[5] Further, the Company currently has a 350 MW Diversity Agreement with Manitoba Hydro, wherein we receive 350 MW of capacity in the summer and Manitoba Hydro receives 350 MW of capacity in the winter. Due to the unique nature of the agreement, it is not included in the list below or reflected in the total hydro capacity specified above.

[5] The Company considers its overall system needs as well as the reasonableness of the costs to customers when determining whether to pursue a PPA or an extension. In the case of the contract with Manitoba Hydro, it is a system capacity service contract and not a standard PPA, as it is not an actual facility resource and is not a dispatchable generation resource like a typical large-scale generator. However, it can provide the necessary baseload capacity and energy. A short-term renewal of the Manitoba Hydro System capacity contract would contribute to the baseload capacity available to meet our near-term capacity obligation while we continue to pursue longer-term resource options, including those that are firm and fully dispatchable on a real time basis. We are currently in negotiations with Manitoba Hydro to extend the system capacity contract, however, because Manitoba Hydro has to serve increasing needs of its own domestic customers, we anticipate any extension to be for a much smaller capacity amount over a shorter duration, likely 5 years or less. We will keep the Commission informed if negotiations are successful.

Table H-5: Existing Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Hastings	Hydro	PPA	4	2033
St. Cloud	Hydro	PPA	9	2041
Dairyland	Hydro	PPA	1.2	2037
Eau Galle	Hydro	PPA	0.3	2026
DG Hydro	Hydro	PPA	0.4	-
SAF Hydro	Hydro	PPA	9	2031
WTC Angelo Dam	Hydro	PPA	0.2	2024
MN Grouped Hydro	Hydro	Own	14	-
WI Grouped Hydro	Hydro	Own	260	-
Manitoba Hydro	Large Hydro	PPA	500	2025

F. Wind

The Company owns or contracts for over 4,300MW of wind power. Over the next two to three years, the Company intends to add 2,800 MW of wind generation from recent acquisitions and Requests for Proposals (RFPs), as well as additional capacity to serve other customer programs.

Table H-6: Existing and Near-Term Wind Resources

Name of Contract or Unit(s)	Type	Owned or Contracted (PPA)	Maximum Capacity (MW)	Retirement/Contract Expiration
Big Blue	Wind	PPA	36	2032
Community Wind North	Wind	Own	26	2044
Fenton	Wind	PPA	206	2032
Garwin	Wind	PPA	37	2028
Jeffers	Wind	Own	44	2044
MinnDakota	Wind	PPA	150	2026
Moraine II	Wind	PPA	50	2029
Community Wind South (Zephyr)	Wind	PPA	31	2032
Lake Benton I	Wind	PPA	104	2028
Odell	Wind	PPA	200	2036
Prairie Rose	Wind	PPA	190	2032
Mower County	Wind	Own	99	2045
Ridgewind	Wind	PPA	25	2031
Border Winds*	Wind	Own	150	2051
Heartland Divide	Wind	PPA	200	2047
Deuel Harvest	Wind	PPA	100	2036
Courtenay	Wind	Own	200	2041
Fowke Wind Energy Center[6]	Wind	Own	100.5	2044
Nobles (Repowered)	Wind	Own	201	2035
Pleasant Valley*	Wind	Own	200	2051
Crowned Ridge (Owned)	Wind	Own	300	2045
Freeborn	Wind	Own	200	2045
Foxtail	Wind	Own	150	2044
Blazing Star I	Wind	Own	200	2045
Blazing Star II	Wind	Own	200	2045
Lake Benton Repower	Wind	Own	100	2044
Dakota Range 1 & 2	Wind	Own	296	2046
Dakota Range 3	Wind	PPA	150	2032
Clean Energy	Wind	PPA	106	2039
Crowned Ridge (PPA)	Wind	PPA	300	2044

**Unit to be repowered*

[6] Formerly known Grand Meadows, the asset has been repowered and renamed.

G. Solar

By 2024 the Company anticipates it will maintain a total of 2,276 MW of solar capacity, via ownership or PPA, to serve our customers. This includes approximately 1,152 MW of large grid-scale solar, over 899 MW of Community Solar Gardens (interconnected by 2024), 3 MW of Solar*Connect Community in Wisconsin, and nearly 202 MW of small-scale distributed solar, and an additional 20 MWs small-scale distributed solar in Wisconsin.

Table H-7: Existing and Near-Term Solar Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Slayton	PV	PPA	2	2033
St. John's	PV	PPA	0.4	2030
School Sisters of Notre Dame	PV	PPA	0.7	2030
Other RDF & Small Solar	PV	PPA	3	Various after 2030
Lake Hallie Solar	PV	PPA	5	2050
Apple River	PV	PPA	100	2045
Aurora	PV	PPA	100	2036
Fillmore	PV	PPA	30	2041
Louise	PV	PPA	50	2041
Marshall	PV	PPA	62	2042
North Star	PV	PPA	100	2042
Sherco Solar 1 (West)	PV	Own	230	2059
Sherco Solar 2 (East)	PV	Own	230	2060
Sherco Solar 3	PV	Own	250	2060
WI DG Solar	PV		20	Various
DG Solar[7]	PV		191 (2023)	Various
WI Solar*Connect Community	PV		3	
Community Solar Gardens	PV	PPA	899(2023)	Various

[7] Includes Solar*Rewards and Made in MN Solar.

III. GENERIC FUTURE RESOURCE OPTIONS

For this Resource Plan, we employed generically defined potential additions resources in our EnCompass modeling. We utilized EnCompass modeling to develop a set of generic resources, informed by project experience and expertise, stakeholder input, and third-party studies like the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline (ATB). These potential additions of non-specific resources are used to represent the size, type, and timing of future resource additions to our system. The performance and cost metrics for these generic resources are derived from third-party studies like NREL's 2023 ATB, consultant estimates, and/or our own internal data. Our analysis covers both supply-side and demand-side resources, as well as the transmission cost implications within the MISO network. See Appendix F: EnCompass Modeling Assumptions and Inputs for further details.

We have accounted for the impacts of the Inflation Reduction Act (IRA) financing within the stated cost assumptions. Costs to transfer credits are not specifically included. Generic resources are not tied to specific locations or ownership models for purposes of the IRA; instead, they guide the overall dimensions of future resource needs. In general, specific resources are acquired through a competitive resource acquisition process, following approval in a Resource Plan proceeding. For further discussion surrounding the impacts of the IRA, refer to Appendix U: Inflation Reduction Act.

A. Supply Side Resources

Centralized supply-side resources available for capacity expansion includes renewables such as battery, hybrid, and thermal generation facilities. Our modeling includes various resource types such as wind and solar, standalone battery and hybrid solar plus battery storage, combustion turbines, and reciprocating engines. Unlike previous resource plans, we have not included a combined cycle resource option. Within our modeling, the generic representative plant size is consistent with NREL ATB assumptions. We are not assuming any difference in costs between Company-owned assets, or those subject to PPAs. Detailed attributes for each resource are further elaborated, with cost and performance assumptions specified in Appendix F.

1. Wind

Wind generators designed to generate electricity by harnessing the kinetic energy of wind. These plants consist of multiple wind turbines strategically placed in areas with high wind speeds to maximize energy production. The turbines are equipped with blades that rotate when exposed to wind, driving a generator that converts mechanical energy into electrical energy. The electricity generated is then fed into the electrical grid, contributing to overall energy supply. Our generic wind resource option is based on the 2023 NREL ATB study, and therefore reflects a 200 MW nameplate capacity and net capacity factor of approximately 44 percent. The forecasted wind costs in our modeling also reflect the 2023 NREL ATB study. IRA production tax credits (PTCs) are included in the NREL ATB "Market + Policies" case and converted to nominal dollar terms. A transmission cost adder is included in the levelized cost of energy (LCOE) calculation for generics not reusing existing interconnection.

2. Solar

Solar power plants generate electricity by capturing sunlight and converting it into electrical energy. These plants use photovoltaic panels or concentrating solar power systems to capture solar radiation. Our generic large-scale solar resource option based on the 2023 NREL ATB study, and therefore is sized at 100 MW on a nameplate capacity basis with a net capacity factor of is approximately 23 percent. We use forecasted solar costs from the publicly available LCOE data in the 2023 NREL ATB. Similar to the adjustments for wind resources, this cost has been adjusted for IRA PTCs in the NREL ATB "Market + Policies" case and converted to nominal dollar terms. Transmission cost adder is included in the LCOE calculation for generics not reusing existing interconnection.

For this Resource Plan, our modeling also includes a forecast of distributed solar bundles adoption, applied as a supply-side resource with an assumed adoption rate. See Section III.C.1 below.

3. Standalone Battery Energy Storage

A battery system is standalone energy storage designed to store electrical energy for later use, independent of any other energy generation source. The generic units are sized at 60 MW with either a four-hour or 10-hour configuration. An annual net capacity factor limit is applied to each generic battery to reflect the one cycle per day operational constraint and the model can economically dispatch batteries based on system needs. We use forecasted standalone battery capital and fixed O&M costs from the publicly available data in the 2023 NREL ATB. These costs are converted to nominal dollar terms and the IRA Investment Tax Credits (ITCs) are applied in the model; as the NREL ATB cost does not include ITCs for standalone storage. A transmission cost adder is included in the capital cost calculation for generics not reusing existing interconnection. For more discussion on storage, see Appendix I: Minnesota Energy Storage Systems Assessment.

4. *Solar-Plus-Storage Hybrid*

Hybrid solar plus energy storage combines solar power generation with battery storage that integrates solar power generation capabilities with energy storage solutions to create a more reliable and efficient energy supply. In our planning, we developed a hybrid unit sized at 130 MW-DC solar plus 60 MW-AC four-hour battery with a 100 MW-AC Inverter. We use the forecasted LCOE from the publicly available data in 2023 NREL ATB. This cost was adjusted for IRA ITCs and converted to nominal dollar terms in the NREL ATB "Market + Policies" case. A transmission cost adder is included in the capital cost calculation for generics not reusing existing interconnection.

5. *Natural Gas Combustion Turbines*

Combustion Turbines (CTs) are a type of power-generating resource that utilize the combustion of fuel, often natural gas, to drive turbines and produce electricity. In our planning, we have developed two generic CT options with capacities of 232 MW and 374 MW. We identified generator cost and performance assumptions from external sources, original equipment manufacturers, and internal engineering assessments.

6. *Reciprocating (RICE) Engines*

Reciprocating engines operate on the principle of converting linear motion into rotational motion through the use of pistons and a crankshaft—like the internal combustion engines in most vehicles. They are highly flexible and can ramp up quickly, making them suitable for peaking and load-following applications. In our planning, we modeled reciprocating engines in modular increments of 6 × 18 MW engine configurations. The cost and performance assumptions for these engines are derived from a combination of industry data, original equipment manufacturers, and our internal engineering assessments.

B. Demand Side Resources

Demand-side resources continue to evolve as the efficiency of equipment grows, beneficial electrification is expanded, and we begin to address not only customer equipment but how energy is being used within a home or business. This evolution requires careful consideration of how best to model resources moving forward. In this plan, the Company has updated energy efficiency based on our proposed 2024-2026 Energy Conservation and Optimization (ECO) Triennial Plan and has modeled the significant demand response portfolio available today against other resource alternatives in EnCompass modeling. We believe these modeling approaches will be modified further in future planning years as differing technologies are available, including streamlined customer-sited batteries, advanced metering technologies, and Distributed Energy Resource Management Systems, impacting the modeling approaches specific to customer energy usage and flexible load resulting from customer actions.

1. *Energy Efficiency (EE)*

The Company continues their commitment to aggressively pursuing EE as an alternative least cost resource. Three scenarios of achievement based on statutory requirements, our most recent 2024-2026 ECO Triennial filing[8], and the optimized scenario of high achievement (as identified in the 2019 IRP) were created to model EE. Each bundle is modeled in Encompass in the same manner as a supply side resource. In addition to bundles, naturally occurring EE is embedded in the load forecast.

2. *Demand Response (DR)*

Demand Response (DF) resources can offset the need for additional resources. The Company recently exceeded the Commission's 2019 requirements to secure an additional 400 MW of load[9] significantly increasing these resources. In this resource plan, the Company reviewed these changes and modeled various bundles to incorporate DR in the same manner as a supply-side resource.

Further detail regarding specific modeling scenarios for both EE and DR can be found in Appendix F. Detailed descriptions of these resources can be found in Appendix J: Distributed Energy Resources.

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[8] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.

[9] *See Order Approving Plan with Modifications And Establishing Requirements for Future Filings,* Docket No. E002/RP-19-368, April 15, 2022 at Order Point 2.A.2

C. Resource Option Sensitivities

Sensitivities on the Preferred Plan were run on all baseload scenarios, and in discrete special cases to help us understand potential differential futures. Sensitivities help us assess risk for individual scenarios by isolating the effects of each sensitivity. We run through the impacts of each below.

1. DG Solar Special Study

Our modeling includes a forecast of distributed rooftop solar bundles adoption, applied as a supply-side resource with an assumed adoption rate. In addition to these static forecasts, we include an additional model sensitivity on the Preferred Plan involving amounts of distributed rooftop solar resources.[10] Unlike the forecasted distributed rooftop solar bundles adoption already included in the Preferred Plan, these rooftop solar projects incur an acquisition cost from the Company. Unlike nearly every other resource option considered in this resource plan, the only costs for this resource that are included in EnCompass are acquisition costs and mandatory tariff payments. While these costs are the only new costs borne by the NSP system, they do not represent the customer's (i.e., the solar owner's) full cost of the distributed rooftop solar system, nor do they represent the bill or rate impacts for all other customers from their implementation.[11] The assumptions used in modeling are discussed in more detail in Appendix J and Appendix S: Stakeholder Engagement

2. Emerging Technology

Achieving our Company-wide vision of a carbon-free electricity supply by 2050 will require significant technological developments that either do not yet exist or are not yet commercialized. In particular, our system will need stable baseload and dispatchable carbon-free generation, and energy storage technologies that can help us maintain reliability for every hour of every day, while simultaneously keeping electricity safe and affordable for customers. As such we have developed sensitivities to account for: (1) hydrogen, (2) long duration storage, and (3) advanced nuclear/small modular reactors in our special study on the Preferred Plan.

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[10] DG solar forecasted by the Company includes base level (naturally occurring customer-owned solar, Solar*Rewards, small qualified facility (QF) solar, existing/approved NSP system solar resources & CSGs), and mandated (New CSGs & Large DERs (3% legislation, 0 – 10 MW)) solar.

[11] Given the way net metering is structured, although it does not create a revenue requirement impact on the resource side of the ledger, it artificially decreases sales, thereby increasing the revenue requirement to be recovered from all other customers.

For hydrogen, we modeled green hydrogen cost from the S&P Global forecast paired with renewable sources and blended the hydrogen with natural gas. Assumptions were sourced from vendors and industry research. For the long duration storage, we assumed 100-hour duration and sourced assumptions from vendors. For the advanced nuclear/small modular reactors, we took costs from 2023 NREL ATB conservative case assumption on costs and operating parameters. Discussion of these advanced emerging technologies is included in Appendix X: Advanced Technologies. We are continually assessing innovative technologies that may be viable options for future resource plans.

IV. POTENTIAL RESOURCES NOT CONSIDERED IN MODELING

We considered several additional technologies in initial screening that were not included in our modeling due to economic viability, technical limitations, operational complexity, or otherwise not aligning with the Company's strategic priorities.
We will continue to monitor and screen these options for possible pilot programs or inclusion in future resource plans, pilot programs, and/or allow them to compete in competitive resource acquisitions so that we may gain additional information on their potential operating characteristics and costs. Although we are excluding such resources from our modeling for the reasons set forth below, that does not mean we will necessarily preclude participation of such resources from future acquisition proceedings. It is possible that as part of a future resource acquisition or contract extension, some of these resource types could potentially displace other generic resource options identified in this Plan. For example, a cost-effective biomass plant could potentially beat out a natural gas peaking plant, or a pumped-hydro facility could beat a battery energy storage system, in future resource acquisition proceedings.

A. Biomass

New biomass resources were excluded from consideration as generic options, primarily due to cost. Generic estimates for biomass resources from the U.S. Energy Information Administration (EIA), and other sources, indicate that the capital costs of new biomass resources are substantially higher than those associated with generic wind, solar, and natural gas resource options. As a result, we did not include a generic biomass resource for consideration in the modeling.

B. Combined Heat and Power (CHP)

Combined Heat and Power (CHP) was not included as a generic resource option, as studies indicate it will have limited economic potential during the planning period.

As part of a prior resource plan, the Company worked with Electric Power Research Institute (EPRI) and ICF International to evaluate the technical and economic potential for CHP applications in our Minnesota service area. The study estimated a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential inthe Company's Minnesota service territory. Under the base scenario, CHP adoption was estimated at 43 MW through 2039. The study was provided as Appendix S to our 2020-2034 Upper Midwest Integrated Resource Plan.

C. Pumped Hydro

Pumped hydro is a mature flexible-duration storage technology with a relatively long operational life; however, environmental challenges and resource economics have generally limited its growth. Further, pumped hydro unit configurations and costs are largely site specific, which makes it a difficult resource to represent generically. As a result, the Company did not include a generic pumped hydro resource for consideration in modeling.

D. Coal

New generic coal resources were eliminated from the list of resource options due to cost, environmental challenges, and non-alignment with the Company's strategic goals. Capital costs for generic coal resources are high relative to other resource types. With low natural gas prices, increased renewable penetration, policy and regulatory risk, new coal resources are not competitive and are faced with significant environmental challenges. Furthermore, adding coal resources with high carbon emission levels would not align with our commitment to a 100 percent carbon-free electric system.

E. Combined Cycle (CC)

New generic Combined Cycle (CC) resources were eliminated from the list of resource options primarily due to their cost and environmental impact. Studies and market data indicate that the capital and operational costs of new CCs are not competitive when compared to renewable energy options like wind and solar. Additionally, the emissions profile of CCs does not align with our Company vision and state policy objectives. As a result, the Company did not include a generic CC resource for consideration in modeling.

APPENDIX I – MINNESOTA ENERGY STORAGE SYSTEMS ASSESSMENT

I. INTRODUCTION

We are seeing a growing interest in the benefits and potential of energy storage systems as we transition to a cleaner, more renewable, future. Pilot programs are being implemented to evaluate the benefits of using energy storage to manage grid reliability, storage is being co-located along with generation, and we are witnessing the rise of hybrid storage plus assets to help utilities transition to a cleaner more renewable future. We expect adoption of energy storage technology to grow as costs decrease; renewable generation increases; and regulators, utilities, and the public across the country increasingly prioritize clean energy and decarbonization goals.

Xcel Energy has long taken a leading role in integrating energy storage into our operations in investing in energy storage projects across our system. Our continuing targeted initiatives and programs will assist us in prioritizing the cost-effective use cases for energy storage as we gain further experience and expertise in energy storage deployment. As we continue to develop operational experience and greater understanding of storage's strengths, and operational constraints, we will utilize this experience as we progress toward aggressive carbon reduction goals.

II. ENERGY STORAGE ASSESMENT

Minn. Stat. § 216B.2422 requires that utilities include an assessment of energy storage systems in their resource plan filing:

> Subd. 7. **Energy storage systems assessment.**(a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:
>
> (1) meeting identified generation and capacity needs; and
>
> (2) evaluating ancillary services.
>
> (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).

Energy storage itself is nothing new and has existed for decades.[1] FERC defines energy storage as any energy asset that is:

[1] Krista Hughes, Stacey Simone Garfinkle*, Planning for A Rainy Day: The Future of Energy Storage and the Policies Driving Its Growth*, Nat. Resources & Env't, Spring 2018, at 31, 33.

> Interconnected to the electrical grid and is designed to receive electrical energy, to store such electrical energy as another energy form, and to convert such energy back to electricity and deliver such electricity for sale, or to use such energy to provide reliability or economic benefits to the grid.[2]

Energy storage encompasses a wide variety of technologies that store electrical energy directly (e.g., capacitors) or after converting to some other form of potential or kinetic energy. Energy storage can take the form of pumped hydro, compressed air, flywheels, various types of batteries, thermal technologies, and hydrogen. While we have deployed a number of these technologies across our system in the past, we will continue to gain experience with others in the future.

We envision four key areas in which energy storage can add value to our system: renewable integration, grid support, deferred investment, and power quality. First, energy storage can support integrating renewables generation into the grid by helping to shift renewable energy to time periods when it is needed, especially for short-term deviations of a few minutes to a few hours. Second, energy storage can help with grid reliability and resilience by providing voltage support, and various ancillary services such as frequency regulation, spinning reserves, operating reserves, energy arbitrage, readily available reserves, and black start capability. Third, energy storage has the potential to replace large traditional grid investments across our system, including investments in peaking generation, transmission and distribution upgrades, and reliability investments to maintain grid support.[3] Finally, energy storage can improve power quality by helping avoid momentary outages that interfere with the operation of sensitive electronic equipment. Because of these benefits, we are optimistic about the role of energy storage in our transition to a cleaner and more renewable future.

Storage has inherent limitations that policymakers and utilities must keep in mind as we invest in the energy system of the future. Energy storage for instance has a declining marginal capacity value; therefore, it is not technically or economically feasible to use storage to continue to shift energy from off-peak to on-peak periods. MISO does not provide accreditation based on storage duration. While energy storage can shave off and lower the top of peaks, it also widens them, thus requiring larger, more expensive storage systems to reduce system energy needs. This problem is

[2] *Third-Party Provision of Ancillary Services; Accounting & Fin. Reporting for New Elec. Storage Techs.*, 144 FERC ¶ 61056 (July 18, 2013).

[3] Though we note that storage has the potential to replace large amount of traditional grid investments in certain instances, we note that generation or transmission and distribution upgrades will continue to be necessary, and the most effective solution in certain applications and locations.

compounded during periods of low renewable production, when excess generation may not be available to re-charge batteries for the next peak. Further, while storage can stack multiple values together, not all benefits can be recognized simultaneously. For instance, a battery cannot simultaneously integrate renewables and provide black start capability. The value of storage must be determined based on the value streams storage provides, and the ability and efficiency of storage to meet our system needs. Finally additional reliability checks may be necessary to ensure that storage is the appropriate resource if it is selected in capacity expansion model runs based on its capacity credit. Given these challenges, a broader suite of resources will be necessary to help us reach our clean energy goals. For further information on storage's ability to provide ancillary services, please see Appendix D: Energy Adequacy Analysis, and for further information on regarding the capacity credit for modeled storage, see Appendix F: EnCompass Modeling Assumptions and Inputs.

Key to capturing the full spectrum of these benefits of storage is the recognition that storage is first and foremost a grid asset. As more and more energy storage is deployed on our system and across the country, it is important that the rules governing ownership and operation of energy storage assets are clear and aimed at maximizing the grid benefits of storage while encouraging its affordable, reliable, and safe deployment. Utilities are uniquely situated to understand the grid and its needs and should play an important role both in owning and operating grid-scale storage. However, at the same time, we are looking for ways to consider how to incorporate the benefits of customer-owned storage, such as working with their customers to aggregate these facilities into Virtual Power Plants (VPPs) or other resources that can provide utility benefits. For example, Xcel Energy's Colorado Subsidiary, Public Service Company's Residential Battery Connect Demand Response Pilot ran for 18 months and aimed to understand the performance and demand management capabilities of residential battery storage systems. Key findings included that batteries can be dispatched quickly during events, their performance is not diminished during back-to-back events, and most participants were highly satisfied with the pilot, citing various motivations for enrollment including grid reliability and environmental benefits. We are developing a similar program in Minnesota.[4] We have provided an analysis of these options, and how they may fit within our resource plan, in this matter in Appendix E: Load and Distributed Energy Resources Forecasting and Appendix H: Resource Options.

[4] The Company intends to propose this demand response battery program as part of our 2024-2026 Energy Conservation and Optimization (ECO) Triennial via a modification sometime in 2024. We proposed a related Energy Storage Incentive Program, pursuant to Minn. Stat. § 216C.379; *see* Docket No. E002/M-23-459.

III. ENERGY STORAGE ANALYSIS IN THE RESOURCE PLAN

On December 31, 2019, the Minnesota Department Commerce released its "Minnesota Energy Storage Cost-Benefit Analysis," which recommended energy storage become a regular part of the resource planning and competitive bidding processes and emphasized the importance of gaining experience in operating energy storage and understanding both its limits and benefits to the grid. Further, the Commission's April 15, 2022, Order approving the Company's last Resource Plan in Docket No. E002/RP-19-368, required that we "include a deeper analysis of (1) storage options, including options combining solar generation and battery storage...."

Xcel Energy is committed to incorporating energy storage in our resource planning activities. While we see storage as a growing part of our energy system, it must be part of a diverse clean energy portfolio. In this Resource Plan, we developed standalone storage, and solar plus storage hybrid modules for use in our EnCompass resource modeling. The standalone energy storage unit was given the opportunity to select between 4- and 10-hour configurations, while the solar plus storage unit assumed a 4-hour configuration. These energy storage configurations were allowed to compete with other resources to meet energy and capacity needs per the statutory requirement and were able to provide ancillary service to meet spinning reserve requirement of 125.17 MWs based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

Our Preferred plan proposes to add 2,100 MWs of storage between 2027 and 2040, including 600 MWs by 2030. We expect battery storage to play an important role in our resource portfolio. Presently, the most cost-effective Lithium-ion batteries have a four-hour duration. This is not sufficient to meet our reliability needs in most cases, such as when we need added capacity for multi-day contiguous periods. Still, our modeling analysis finds value in the short-duration resources currently available for peak shaving and possibly extending the duration of solar resources into periods of high-load.

Our assumptions for standalone storage, and solar plus storage, were based on the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline (ATB). NREL's 2023 ATB was designed to (1) document transparent, normalized technology cost and performance assumptions using published sources; (2) document potential pathways for impacts of R&D on renewable energy technologies; (3) enable consistency in technology assumptions across analysis projects; (4) facilitate the tracking and sourcing of input assumptions; and (5) reduce the lead time required when conducting scenario analysis of 5- to 30-year futures. The NREL ATB is updated each year to provide technology cost and performance assumptions. We have traditionally utilized the ATB to provide cost assumptions for different nonthermal resource types. The characteristics and cost assumptions for storage resources can be found in Appendix F.

We continue to consider new tools and processes to analyze the energy storage solutions including the evaluation of potential values storage assets might provide to the system. For instance, Appendix Y: Life Cycle Emissions Impacts provides a literature review to examine a comparison between different electricity generation and storage technologies. The goal was to examine the carbon impacts throughout the life cycle of different electric generation alternatives to provide a comprehensive assessment of the environmental footprint of a resource over the life of the asset. The literature review suggested that renewable energy sources and storage paired with renewable generation exhibit much lower life cycle emissions compared to fossil fuel-based technologies. We are also examining long duration storage as a sensitivity, as discussed in Appendix X: Advanced Technologies, though we note the long duration storage, such as our Form Energy Pilot, is in test phases, and not ready yet for commercial deployment.

IV. CONCLUSION

Our Preferred Plan adds storage, and we expect storage to be part of our resource portfolio as costs continue to decline and we add more renewables to our system. Like other resources, much of the value of storage is in its ability to provide capacity and energy (arbitrage). We expect these needs to help drive storage additions in the future as we continue to explore near-term storage opportunities that could provide value to our system.

APPENDIX J – DISTRIBUTED ENERGY RESOURCES

I. INTRODUCTION

For purposes of this Resource Plan, Distributed Energy Resource (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, whether installed on the customer or utility side of the electric meter. The definition further clarifies that for the IRP, DER may include, but is not limited to distributed generation, energy storage,[1] electric vehicles,[2] and demand side management. As discussed in our November 1, 2023, Integrated Distribution Plan,[3] future grid modernization investments will be necessary to integrate more DERs, keep pace with load growth, and ensure efficient and sound operations in an increasingly complex environment.

In the context of this IRP, DERs are an essential part of our path towards carbon reduction and often keep costs low to customers. In this appendix we describe in more detail the importance of these resources and how they have been addressed as part of our Preferred Plan.

II. DEMAND SIDE MANAGEMENT

Demand Side Management (DSM) is the modification of customer demand for energy through various customer changes including installing more efficient equipment, altering usage patterns of energy (such as washing laundry at a certain time of the day), or reducing overall energy consumption through energy conservation. The methods utilities use to influence these decisions are typically through education and financial incentives. DSM enhances our customers' experience with opportunities to reduce energy and ways to manage their energy differently. By empowering customers with insights and technology, we can provide tools for them to lower their overall energy bills. In addition, DSM, through these customer actions, will help avoid the need for future generation resources and enable CO_2 emissions reductions.

Xcel Energy is proud to contribute to Minnesota's status as a national leader in DSM. Minnesota has held this designation for more than a decade. In fact, the state's utility-sponsored energy efficiency programs are among the longest standing in the country, and Minnesota is the only Midwestern state that has consistently ranked in the top ten on the American Council for Energy Efficient Economy's (ACEEE) State Energy

[1] Energy storage is discussed in Appendices E, H, and I.
[2] Electric vehicles are discussed in Appendix E.
[3] Docket No. E002/M-23-452.

Efficiency Scorecard. Minnesota utilities' energy savings achievements through DSM have saved billions of dollars for customers and avoided millions of tons of greenhouse gas and other pollutants while creating and supporting jobs in the state.[4] In 2023, ACEEE's utility energy efficiency scorecard designated Xcel Energy Minnesota 10th out of 53 large electric utilities.[5]

The value of DSM continues to evolve from traditional energy efficiency (EE) measures that permanently reduce customer consumption and demand response (DR) efforts that reduce customer load during traditional system peak hours, to programs that leverage the additional benefits of reducing energy at certain times of the day, typically when energy supply costs are cleaner and/or less costly. These traditional EE and DR resources will continue to have a significant role in future DSM portfolios. As the future unfolds, however, the portfolio will need to explore new integrated technologies that optimize DSM solutions by location and time impacting energy usages versus demand. For example, new technologies (such as smart thermostats) also offer benefits beyond simply reducing overall and peak usage, including features that make it easier for customers to shift energy use to non-peak times when energy is less expensive. As we begin to shift our efforts towards optimization of energy use, the impacts of DSM as a resource will simultaneously evolve. Whereas energy savings targets were once focused on permanent reduction of load, we instead see benefit in focusing on the timing of energy use. This adjustment will be seen in resource planning as incremental demand reductions that grow smaller over time or even a slight reduction in the overall future demand reduction opportunity. This does not represent t a reduction in the Company's commitment to DSM.

The Company is pleased to be part of a broad bipartisan coalition who supported passage of the landmark Energy Conservation and Optimization (ECO) Act of 2021. ECO has modernized the framework for customer-funded utility programs and re-imagined the scope of what such programs can include as we begin to embrace new technologies and optimization efforts leading to the future of these portfolios as described above. In our first ECO Triennial Plan,[6] the Deputy Commissioner approved the Company's proposal to achieve electric savings of two percent of sales and 1.5 percent of natural gas sales, both of which exceed the statutory minimum.[7,8]

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[4] The Aggregate Economic Impact of the Conservation Improvement Program 2008-2013, Minnesota Department of Commerce, Division of Energy Resources, Cadmus, October 2015. https://mn.gov/commerce-stat/pdfs/card-reportaggregate-eco-impact-cip-2008-2013.pdf

[5] 2023 Utility Energy Efficiency Score Card, ACEEE, August 2023

[6] Docket No. E002/CIP-23-92.

[7] Decision, *In the Matter of Xcel Energy's 2024-2026 Energy Conservation and Optimization Triennial Plan*, Department of Commerce, December 1, 2023.

[8] Minn. Stat. 216B.241.

Our Triennial Plan proposed programs and savings targets that continued our long-standing commitment to energy efficiency and recognized the value of customer programs does not stem solely from the reduction of energy consumption. The ECO Act opened the door for load management (demand response) programs that go beyond traditional peak-hour load shedding and seek to optimize the time at which customers use energy. With this change, the Company can work with customers to help them use electricity at low-cost and low-emission times of day, benefitting the grid, the climate and the customer simultaneously.

In perhaps the most transformational change enabled by ECO, the Triennial Plan also includes proposals to support customers who seek not only to use energy more efficiently, but to change the form of energy they use through efficient fuel-switching (EFS). The Company believes that the incentives and support for EFS included here will both support customers interested in fuel-switching and provide avenues to learn and develop enhancements that can help scale EFS activity in future years.

Our Preferred Plan complies with Commission orders and continues our commitment to energy efficiency and demand response, with total energy efficiency reductions (including both programmatic and naturally occurring energy efficiency) of 780 GWh on an average annual basis and demand response of 1,385 MW throughout our plan. We summarize DSM efforts in more detail below.

Energy Efficiency

The Company is committed to aggressively pursuing energy efficiency. The Preferred Plan will achieve between 2-2.5 percent annual energy savings at an annual energy savings level of 582 GWh for all planning years through programs we administer. As discussed below, when combined with naturally occurring energy efficiency, the Preferred Plan includes total energy efficiency that exceeds 780 GWh on an average annual basis. Specific details regarding how the Company will achieve energy efficiency will continue to be addressed in our Triennial Planning process.

The Company has also identified energy efficiency impacts that are naturally occurring as part of our energy demand forecast. These can be described as routine adoption of efficient measures outside of programs or progression of codes and standards that specify minimum performance levels. Where a major step change in codes and standards occurs (e.g. implementation of a federal 45 Lumen per watt efficacy requirement for general service lamps or an acceleration of required performance in non-residential buildings as required in a state law adopted in 2023), the Company can calculate these effects to demonstrate the effect of energy conservation that is not accounted for in the programs we administer through ECO. As part of the Preferred Plan, we estimate this to account for an additional 40 percent savings on top of those estimated as part of administered programs under ECO.

Demand Response

At the end of 2023, the Company exceeded the Commission's 2019 requirement to secure an incremental 400 MW of load. Many of these resources focus on the reduction of load during summer peak days or test customer interest and access to shifting opportunities. For our demand response portfolio to continue to be successful, we need the flexibility to procure resources and modify load for localized events and timing across all months of the year.

Our Preferred Plan includes 1,365 MW (of demand response resources as part of our five-year planning period. Our Preferred Plan aims to maintain load reduction through traditional resources with a moderate increase in load. This moderation is a result of the significant increase of available load as ordered from previous resource plans.

The Company has also begun to look at load flexibility as a resource. However, rather than model it as a resource like energy efficiency and demand response, we have identified the system needs that could be addressed by load flexibility. This will allow us to design load flexibility programs that can effectively produce system benefits by optimizing location and timing of the programs to minimize the net cost to all customers. This is discussed further as part of Section III below.

A. Energy Efficiency (EE)

On December 1, 2023, the Deputy Commissioner approved Xcel Energy's first Triennial Plan under the 2021 Energy Conservation and Optimization (ECO) Act. This landmark filing continues the Company's commitment to energy efficiency and demand response, setting targets at over the statutory minimum requirements, increasing budgetary spending for income qualified customers and laying out specific programs and requirements for efficient fuel switching – now allowed by ECO. With over 40 energy efficiency programs, ranging from Home Energy Squad visits providing energy efficient equipment installed directly in customers' homes to Process Efficiency programs providing comprehensive whole-building energy efficiency analysis, the Company continues to provide emerging technologies and program models to our customers.

Below, we discuss the requirements related to energy efficiency, the historical performance of the Company's ECO program, how the planning outlook was determined in the Preferred Plan, and the results of our modeling. The Company does not provide a specific action plan for energy efficiency in this filing, as this was approved in Docket No. G,E002/CIP-23-92 on December 1, 2023.

1. *Naturally Occurring Energy Efficiency*

The energy savings resulting from naturally occurring energy efficiency includes: customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by EE programs, but in the future would not be part of an energy efficiency program because an efficient technology is required to meet code or has become common practice. The level of energy efficiency occurring as part of the utility's ECO programs depends on what is allowed to be counted towards state savings targets. As a result, the achievements claimed by the utilities represent only a portion of the savings realized. For example, the Department of Energy and the Environmental Protection Agency have had success in recent years through their ENERGY STAR efforts working with electronics manufacturers and retailers to produce and stock more efficient models. Energy efficiency is increasingly being driven by multiple influencers in the market, some of them benefiting from utility programs and others driven by the market.

The Company has taken this into consideration as we developed our modeling techniques for energy efficiency. The Company has analyzed historical load compared to future customer demand forecasting to determine that customers are becoming more efficient than can be explained by our DSM portfolio alone. Comparing our future ECO program portfolios and applying an estimated 40 percent increase (estimated based on historical trends) shows the Company meeting and, in the short-term, exceeding 780 GWh of energy efficiency as modeled in previous resource plans. The Company has bifurcated naturally occurring energy efficiency to show the true nature of "conservation" where not all energy savings can be claimed through demand-side management (or in this case our ECO programs).

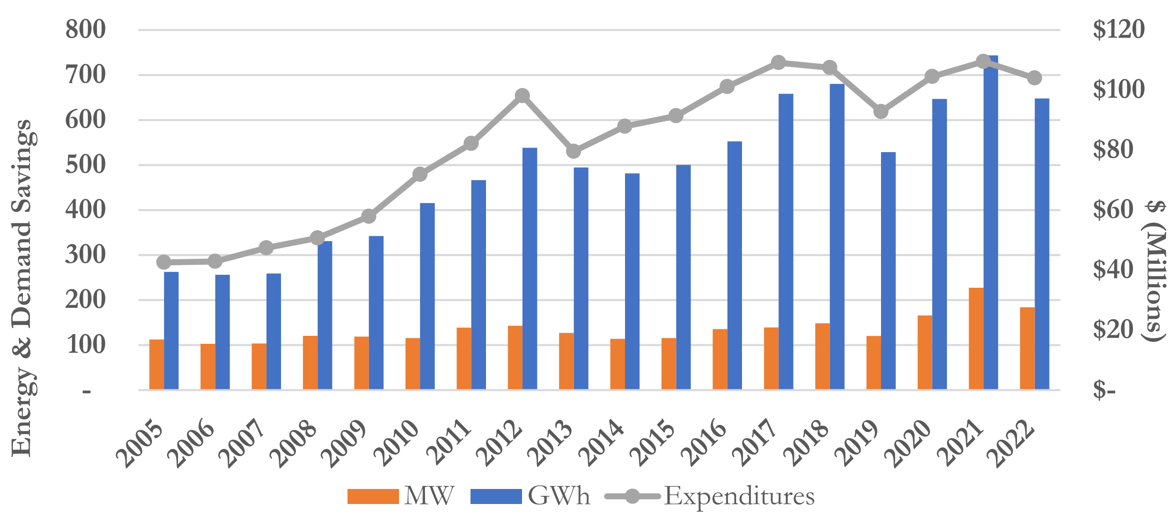
2. *Integrated Resource Planning Requirements for Energy Efficiency*

In connection with the Company's last IRP, the Commission's Order in Docket No. 19-368, issued on June 14, 2022, requires the Company, in Order Point 2.A.1, to "save, on average, at least 780 gigawatt-hours via energy efficiency." The Company's EE initiatives, reflected in the Preferred Plan meets this requirement. As discussed below, our Preferred Plan increases our projected EE savings in this planning period beyond the requirements of Minn. Stat. § 216B.241, which requires the Company to save 1.75 percent of retail sales yearly. Rather, the Preferred Plan extends these savings between 2-2.5 percent at an annual energy savings level of 582 GWh for all planning years. Combined with naturally occurring energy savings, which is estimated to increase these savings by up to 40 percent, the Preferred Plan meets Commission's order.

3. *Historical Performance of Programmatic Energy Efficiency*

Xcel Energy has one of the longest-running and most successful DSM programs in the country. Between 1994-2022, the Company invested nearly $2.2 billion (nominal) resulting in 11,813 GWh of electric savings, 3,733 MW of electric demand savings. Our efforts continuously grow and modifications to our customer offerings prove worthwhile as we continue to meet and exceed statutory energy savings targets for electricity every year since 2011. Figure J-1 below highlights our historic electric achievement.

Figure J-1: Historical Electric ECO Achievements 2005-2022[9]



Our EE portfolio has had a significant impact on carbon reduction. Technologies and improvements implemented as part of EE programs, generally last for several years. Reductions in energy usage based on these programs have resulted in commensurate reductions in carbon emissions for the same period.

[9] Historical Achievement for ECO includes those demand response savings claimed as part of the portfolio.

4. Energy Efficiency Planning Outlook

The Company's projections for EE savings of over two percent of retail sales are critical to these goals and are based on a combination of two major types of energy efficiency: energy savings from ECO programs and naturally occurring energy savings as customer behavior impacts future load growth. In this section, we discuss the Company's current projections for efficiency savings from ECO programs, how we developed those projections, and the important contribution they make to the targets outlined in the Company's IRP. The Company created three bundles for EE of incremental increasing achievement at incremental increasing cost based on these projections so that EE could be modeled in Encompass in the same manner as a supply-side resource.

a. Energy Efficiency Scenarios

The Company began the development of energy efficiency bundles based on the filed 2024-2026 ECO Triennial.[10] Three bundles of EE were developed, based on (1) minimum statutory requirements, (2) estimated savings derived from our 2024-2026 ECO Triennial, and (3) high achievement.

First, a "Minimum Scenario" was set at the minimum statutory savings requirements set by Minnesota Statute § 216B.241; we reference this as Bundle 1. The resulting savings are set at 1.75 percent of weather normalized sales for the three prior years before a triennial is filed. The savings for 2024-2026 was set based on sales in 2020-2022, and the savings for 2027-2029 was set based on the sales forecast for 2023-2025. This trend continues every three years through the end of the modeling period.

Second, a "Programmatic Scenario" was created for Bundle 2 based on the Company's filed 2024-2026 ECO Triennial. The years 2024, 2025, and 2026 match the energy efficiency savings filed in our plan excluding the demand response segment (these are modeled separately as part of the IRP). The savings in 2027-2029 are included as the average of 2024-2026 since market conditions and codes and standards should remain consistent enough through this time. Starting in 2030 the programmatic savings drop to reflect the latest federal lighting efficiency standards.[11] This standard will essentially remove all savings from screw in bulbs, so these savings were removed from the 2024-2026 portfolio to calculate a percent reduction in programmatic savings.

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[10] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.

[11] Federal legislation includes the 2007 Energy and Independence and Security Act (IESA) that adjusts baselines for lighting technologies.

Finally, a third bundle was provided as a selectable resource by the EnCompass model. This final bundle was created as a high-level scenario with a significant cost increase for program administration. This scenario was based on the high scenario of our 2020-2034 IRP which took into account the most recent state potential analysis for energy efficiency.[12]

Table J-1: Energy Efficiency Scenarios

	2024		2028	
	GWh	**Costs ($M)**	**GWh**	**Costs ($M)**
Bundle 1	477	$86	468	$82
Bundle 2	615	$134	623	$140
Bundle 3	774	$214	870	$264

Costs for these bundles were developed based upon the filed 2024-2026 ECO plan. For all bundles, the total cost is made up of two parts: an administrative cost and a cost of rebates to achieve these savings.

- Administrative Cost: Administrative cost is the total cost of the portfolio minus rebates. For the Programmatic bundles year 2024-2026 the filed costs were used. The Company assumed that administering energy savings programs varies directly with the size of said programs because of this the Company used a constant dollar-per-kWh metric from the filed programs to determine costs of all other years.
- Rebate Costs: The Company used the costs from the 2019 Potential Study to develop a cost curve to determine the costs of our high bundle and minimum bundle in relation to our Programmatic bundle which utilized specific rebate costs as filed in the 2024-2026 ECO Triennial.

All of the bundles use the same load shape, which is based on the filed 2024-2026 ECO Triennial plan. The shape was developed by combining the filed load shapes for each measure. To do this the total lifetime energy savings for each shape were used to determine weighting factors on which to combine the shapes. This results in alignment between the EE summer peaking shape and the Company's overall peak shape.

b. Modeling Results

The Company continues its commitment to Energy Efficiency as part of the 2024-2040 IRP. As part of the modeling process, both Bundle 1 and Bundle 2 were used as the

[12] Upper Midwest Integrated Resource Plan 2020-2034, Xcel Energy, Docket No. E002/RP-19-368, 2019.

baseline for the Encompass model. The first because of compliance requirements and the second as a result of the Company's commitment to energy efficiency through the 2024-2026 ECO Triennial and anticipated growth over time. Bundle 3 was not chosen as part of the modeling analysis due to the cost of additional energy efficiency.

The Preferred Plan includes lower energy efficiency levels as compared to our previous IRP planning process. However, this Plan has also captured natural occurring energy efficiency savings with a reduction of the energy forecast. This is an important aspect of our Preferred Plan, as the Company sees the reduction of lighting technologies available through ECO as LEDs become mainstream in the market and many newer technologies focus on the reduction of natural gas or shifting of load rather than permanent reductions.

B. Demand Response (DR)

Demand Response continues to be a critical part of our overall portfolio. Today, this DR portfolio comprises 14 percent of our total peak load. The growth of these resources has been maintained over several years by adjusting our programs, modifying control equipment and operational controls, and adding new innovative programs for customer participation.

Our Preferred Plan continues the growth of demand shedding resources, but that begins to level out, driven by our anticipation that customers will modify their level of commitment to these programs as they shift demand differently in a future where additional electrification technologies become more mainstream. The Company continues to explore opportunities to shift demand. We believe that, as newer technologies become active (e.g., residential batteries) in the market, systems and tools are put in place to better manage load control (e.g., DRMS), and the Company is able to complete several of their pilots (gaining important customer insights and usage data) we will be able to model these activities more accurately. Right now, this is not feasible because such technologies involve active shifting of resources that may reduce peak demand differently then we have historically seen. This likely will adjust the load that may be available for those programs that traditionally shed load at a specific time in the summer. The Company has included Appendix J1: Demand Management Portfolio Design Whitepaper as written by Opinion Dynamics, as an attachment to this appendix with further explanation of the history of demand response and where load flexibility will take us over time.

Below, we discuss the requirements related to DR, the historical performance of the Company's portfolio, the results of our modeling and DR as part of the Preferred Plan.

1. Integrated Resource Planning Requirements for Demand Response

In connection with the Company's last IRP, the Commission's Order in Docket No. 19-368, issued on June 14, 2022, Order Point 2.A.2 requires the Company to "acquire 400 megawatts of incremental demand response by 2023[.]" As provided in more detail in Docket No. E002/M-20-421 on February 1, 2024, the Company has grown its DR resources by 482 MWs over the last several years for a total of 1,333 MWs as required by Order Point 2.A.2. As described in more detail in our compliance filing, this requirement was met despite the loss of load resulting from the COVID pandemic and general load loss as a result of more efficient cooling systems. Several levers were applied to reach this level of savings including the addition of pilot programs, significant sign-on bonuses to customers, and one-to-one discussions with our largest customers. This unprecedented amount of savings exceeds the level of cost-effective demand response availability as found within past potential study analysis.[13]

In addition, Order Point 15 of the most recent IRP Order states in part:

> *Xcel shall include improved load flexibility and demand response modeling methodologies prospectively, including in its next resource plan.*

The Company has altered its modeling of DR resources by expanding our analysis to include additional load characteristics as described further in the modeling analysis of this chapter. Load Flexibility is addressed in Section III of this chapter.

2. Historical Performance of Demand Response

The Company has a large percent of peak load reduction from demand response, now approximately 14 percent of our system peak in the Midwest and remaining an outlier among utilities. In comparison, Otter Tail Power has a little over 10 percent, Baltimore Gas & Electric (BGE) has approximately 5 percent and Consolidated Edison, Nevada Energy and Arizona Public Service (APS) have less than four percent according to U.S. Energy Information Administration (EIA) data.[14] Below, the Company provides the historical details for the growth of demand response through 2023.

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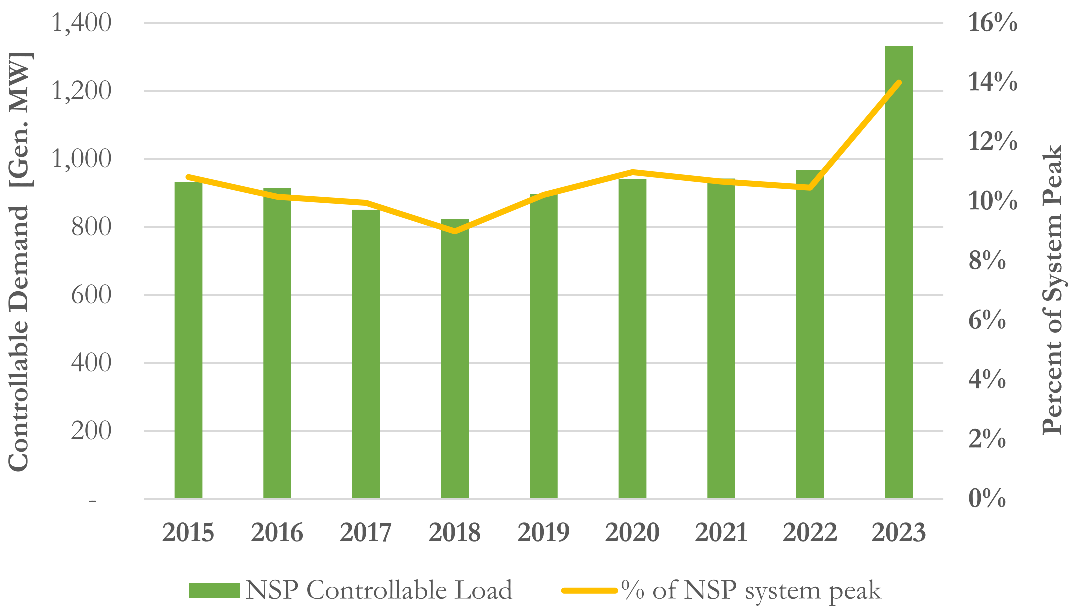
[13] Upper Midwest Integrated Resource Plan 2020-2034, Xcel Energy, Docket No. E002/RP-19-368, 2019, Appendix G.
[14] 2020 data set was used for analysis, available at: https://www.eia.gov/electricity/data/eia861/

Figure J-2: Historical Demand Response Achievements 2015-2023



3. Demand Response Planning Outlook

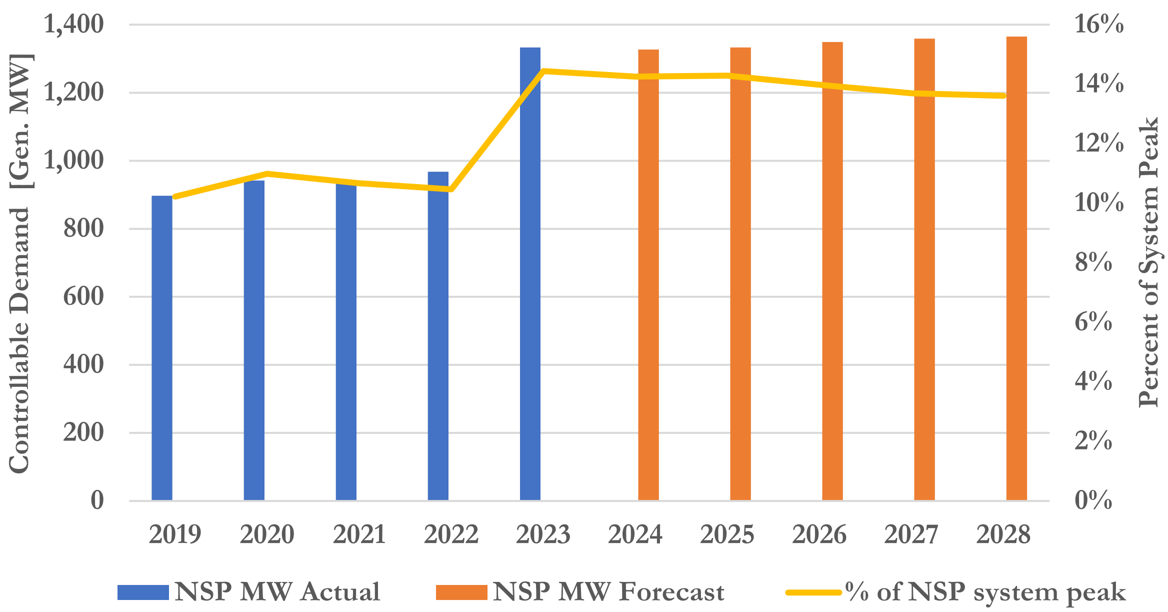
Our Preferred Plan includes 1,365 MW of DR resources as part of our five-year planning period. This is consistent with the achievement of an additional 400 MWs as required by previous Commission orders and our current resource availability.[15]

Our current available load for 2023 for demand response is 1,333 MWs or 14 percent of our peak load for NSP.[16] Our Preferred Plan estimates continued growth of demand response at a moderate pace, increasing load to 1,365 MW in the next five years. This moderate growth shows a slow increase as shedding DR resources have begun to saturate given recent growth efforts. In addition, we anticipate that some of our pilots currently unregistered with MISO may not continue and general load loss will continue as it has for the past five years due to customer attrition. We anticipate that these additional MWs in the five-year planning period will be a result of time-varying rates and load shifting opportunities of new technologies dependent on customer interest, customer behavior and the use of advanced metering technologies.

[15] Our Preferred Plan includes those resources available as a capacity resource, as part of MISO, therefore there may be a slight difference between total available capacity and total contracted load by our customers.
[16] Compliance Filing, Xcel Energy Demand Response, Docket No. E002/M-20-421, February 1, 2024

Figure J-3 below shows the demand response resources included in Encompass as part of our Preferred Plan.

Figure J-3: Controllable Demand (Gen. MW)



In this section, we discuss the Company's current projections for demand response, how we developed those projections, and the important contribution they make to the targets outlined in the Company's IRP.

a. Demand Response Scenarios

The Company created six bundles for demand response based on level of achievement and technology so that DR could be modeled in Encompass in the same manner as a supply-side resource. These bundles included: (1) Base DR, Saver's Switch, (2) Base DR, Other DR, (3) Incremental DR, Saver's Switch, (4) Incremental DR, Other DR, (5) High Potential, Saver's Switch, and (6) High Potential, Other DR.

Consistent with past practice, the Company developed a Base DR Forecast from existing programs, which was included in all baseline resource modeling as the first level of DR achievement. The Company then developed two levels of DR achievement incremental to the Base DR Forecast. The second level of DR achievement represents achievement of the required 400 MW of incremental DR by the end of 2023,[17] and a continuation of that level of achievement beyond 2023. This level of achievement, represented by bundles 1 through 4, is included in the Encompass model as required resources as ordered by the Commission. The third level of DR achievement, represented by bundles 5 and 6, is based on the Brattle DR Potential Study included in the 2019 IRP. This level of achievement exceeds the achievement of the ordered 400 MW by 2023 at a higher cost. These bundles are included in the Encompass model as selectable resources to determine the cost-effective level of future DR achievement.

With each level of achievement, the costs and impacts were modeled separately to account for differing characteristics. These characteristics were defined through technology and control – including load shape and control hours – to create two categories of technologies: (1) Saver's Switch, and (2) Other DR programs.

Within each level of achievement, the costs and impacts of the Saver's Switch program and all other DR programs were modeled separately. This was done as the Saver's Switch program controls air-conditioning,[18] resulting in load reductions that differ significantly from the load reductions from all other DR programs which control a wide variety of loads. This results in a total of six modeled bundles as described above (each level broken into specific technology and control characteristics). Similar to EE, each level of achievement represents an incremental amount of DR and is dependent on the preceding level of achievement being selected (i.e., third level of achievement for the Saver's Switch program cannot be selected unless the second level of achievement is selected). Table J-2 provides the details of these scenarios.

Table J-2: Demand Response Scenarios

	2024		2028	
	MW	**Costs ($M)**	**MW**	**Costs ($M)**
Bundle 1	686	$29.5	692	$29.8
Bundle 2	339	$20.2	375	$22.4
Bundle 3	176	$13.8	178	$13.9
Bundle 4	56	$4.4	61	$4.8
Bundle 5[19]	24	$3.5	31	$4.5
Bundle 6	70	$10.1	59	$8.5

[17] *See Order Approving Plan with Modifications And Establishing Requirements For Future Filings*, Docket No. E002/RP-19-368, April 15, 2022 at Order Point 2.A.2.
[18] Saver's Switch was used as a proxy for characterization of the resource, other programs such as AC Rewards also hold these characteristics.
[19] Bundles 5 and 6 were not selected as cost-effective resources.

For each bundle, an estimate of the MW that varies by month was used and a maximum hour of annual control was also used. For the Bundles that include Saver's Switch (Bundles 1, 3 and 5) the monthly pattern of load relief potential was used to determine the MWs of load relief between May through September (all other months assumed 0 load relief), based on the historically observed air-conditioning load at system peaking conditions within those months. For the Bundles that include all other DR programs, the MWs of load relief across the entire year was based on the historically observed load relief potential each month at system peaking conditions.

Additionally, for all bundles, a maximum number of annual control hours was set, limiting the model to dispatch each bundle across each year in the future. For the Bundles that include Saver's Switch (Bundles 1, 3 and 5), this limit is 300 hours. For the Bundles that include all other DR programs, this limit is 80 hours.

b. Modeling Results

These bundles were optimized and tested as though they were competitive supply-side resources. Bundles 1-4 were set as non-selectable resources because they were already being procured through various demand response programs and therefore are already in existence (or assumed to be in the future). Bundles 5 and 6 were set as selectable resources, meaning they were compared to other supply side resources.

As noted, Bundles 1-4 were non-selectable and included in the Preferred Plan. In addition, Encompass ultimately chose Bundle 6 based on the load profile characteristics of programs that allows for control over several months rather than just peak summer days. This matches the future load profile of the Company and the MISO shift to a seasonal construct.

While the model shows a limited number of additional savings in outer years, the Company believes that as new technologies are developed, load profiles began to alter, and the utility is able to begin to initiate future demand resource management systems (DRMS) we will see additional efforts and opportunities for DR. In the short term, we estimate that these incremental steps will be smaller as programs are piloted and customer interest grows.

III. ADVANCED RATE DESIGN, DEMAND RESPONSE, AND ANY OTHER EFFORTS TO SHIFT CUSTOMER DEMAND

Order Point 13 of the Commission's April 15, 2022 Order in Docket No. E002/RP-19-368 requires the Company to account for anticipated effects of advanced rate design, demand response, and any other efforts to shift customer demand. We discuss demand response in Section II and the remaining efforts below.

A. Advanced Rate Design

On August 7, 2018, the Commission approved the Company's time-of-use (TOU) rate pilot, known as Flex Pricing Pilot.[20] The Pilot operated for two years, from November 2020 to October 2022, and included participants in two geographic areas: Minneapolis (Midtown substation) and Eden Prairie area (Westgate substation). Participants were selected from the eligible population to capture a diverse population base and provide insights into key customer types (income qualified, EV drivers, etc.).

The Pilot aimed to send adequate signals to reduce peak demand; evaluate effective customer engagement strategies; understand customer impacts by segment; support attainment of demand response goals; and understand integration of Pilot elements in our service territory. The findings indicated a modest reduction in demand during summer peak hours. Although usage patterns and their impact on customer bills were relatively minor, the average participant reduced their summer on-peak demand by 1.6 percent, with variations by location and year. The first year showed a consistent response in both regions. However, in the second year, the Eden Prairie area maintained its reduced usage patterns while the Minneapolis area did not result in a statistically valid difference between the treatment and control populations. In contrast, winter on-peak demand reductions in the second year indicated increased engagement from Minneapolis consumers, mirroring the efforts in Eden Prairie.

While the pilot data indicates a directional reduction, the task of deriving a quantitative adjustment to consider when modeling resource needs is complicated by the inconsistent results observed in the pilot. Further, the specific design of a TOU rate can significantly influence its effects. On December 22, 2023, the Company proposed a permanent residential TOU rate that closely mirrors the Flex Pricing Pilot rate.[21] However, as this proposed TOU rate framework includes customers that were excluded

[20] Docket No. E002/M-17-775.
[21] Docket No. E002/M-23-524.

customer classes from the pilot[22] and may evolve during the regulatory process, there remains uncertainty in forecasting its ultimate design and impact. Therefore, until we collect more data and receive Commission approval on a final TOU rate, the Company believes that the potential effects of a TOU rate can be best evaluated as one consideration that could result in the low load modeling sensitivity.

B. Shifting Resources

The Company did not specifically model the shifting of resources as part of this Resource Plan. While we have not modeled what can be considered "load flexibility" as a specific resource such as we would for energy efficiency or demand response, we have proposed a method to determine the generation system assets that can be avoided by these nascent technologies.

There are two reasons for moving forward such as we have. First, many of these resources are currently undefined. For example, an energy management system can be used to shift resources (or load) from one time to another based on a specific signal and/or programmatic scenario developed for the customer. Second, the Company does not have the capabilities to manage customer load at this level – however, we are testing holistic options for these types of custom approaches with customers as part of our 2024-2026 ECO Triennial. These current situations prevent the Company from making reasonable estimates of the potential impact of load flexibility, or when load flexibility can effectively be dispatched. Development of specifically defined bundles of load flexibility to model load flexibility resources in the same manner as EE, DR and supply-side resources is not possible at this time. Opinion Dynamics in their "Demand Management Portfolio Design Whitepaper" states that "many load flexibility value streams have not yet been established or quantified yet, though efforts are well underway, and opportunities abound. Most of the efforts across the country are nascent, with pilots showing promising results."

For this planning period, the Company has instead identified system needs that could be addressed by load flexibility. Batteries have similar characteristics to load flexibility in that they can both provide load relief that can be dispatched a high number of hours throughout the year but also produce an increase in load for other hours. By using the Encompass model to identify potential supply-side batteries as cost-effective resources,

[22] To achieve the goal of drawing conclusions about the entire population from the relatively small sample included in the pilot, certain customers were excluded. These exclusions were necessary either due to their small numbers or the difficulty in matching them with valid treatment-control pairings. Examples of such customers include those with electric space heating, those participating in net metering, and those with medically necessary equipment.

the Company can begin to design load flexibility programs. The charge and discharge hours, magnitude of load relief and the cost of those cost-effective batteries provide information to design load flexibility programs to provide similar load relief characteristics at costs below the supply-side options. Additionally, the design of the load flexibility programs will also consider impacts on the distribution system. This analysis occurring outside of the Encompass model is necessary to design load flexibility programs that can effectively produce system benefits by optimizing location and timing of the programs to minimize net cost to all customers.

Appendix J1: Demand Management Portfolio Design Whitepaper, provides further detail regarding how the Company can prepare for this adjustment from traditional DR resources to "load flexibility." As described in the appendix, several ongoing factors will help unlock the opportunities presented by load flexibility, including AMI deployment and further Grid Modernization.[23] In addition, the Company is currently piloting customer programs and will be focusing on a Virtual Power Plant (VPP) as described in Appendix X: Advanced Technologies and continuing several recently launched programs. As the Company continues to explore these options and learns further from our active pilots, we will incorporate these learnings into alternative forecasting and modeling options in future integrated resource plans.

IV. DISTRIBUTED GENERATION (DG) SOLAR BUNDLES

Order Point 15 of the Commission's April 15, 2022 Order in Docket No. E002/RP-19-368 requires the Company in its next Resource Plan to work with stakeholders to develop a modeling construct that enables the Company to model solar-powered generators connected to the Company's distribution system as a resource. Further, Order Point 15 directed the Company and stakeholders to address the following factors in developing the modeling construct:

A. Using a "bundled" approach as is used to model energy efficiency and demand response.
B. The costs borne by the utility and the costs borne by the customer.
C. Cost effectiveness tests.
D. Other topics as identified by stakeholders.

While we discuss this Order Point below, it is important to note that, since this Order was issued, the regulatory landscape for distributed solar has substantially changed. In 2023, the Minnesota Legislature amended the distributed solar energy standard (DSES)

[23] See Xcel Energy's Integrated Distribution Plan for further details regarding Grid Modernization, Docket No. E002/M-23-452.

set forth in Minn. Stat. § 216B.1691, subd. 2h, to mandate that at least three percent of the Company's retail electric sales in Minnesota must be generated from solar energy generating systems. To be counted towards this standard, the solar generating system must have a capacity of ten megawatts or less, be connected to the distribution system, be located in our Minnesota service territory, and be constructed or procured after August 1, 2023. As a result, our Preferred Plan includes nearly 2,000 MW of Community Solar Gardens and over 1,600 MW of distributed solar resources in compliance with state law.

As detailed in Appendix S: Stakeholder Engagement Summary, we discussed with the Clean Energy Organizations (CEOs) the potential effects of the DSES on the Order Point 15 distributed solar model construct. The CEOs' perspective in those meetings was that the DSES requirement will likely pertain to front-of-the-meter solar, while solar bundling is more likely to occur behind the meter. We agree with this interpretation; however, we anticipate that the DSES will have an impact on the capacity expansion model, and consequently, on the model selection of the solar bundle resource option. Further, we note that since the IRP Order, there are currently multiple dockets with pending decisions that will impact DG Solar development, inclusive of both behind the meter solar generation and distributed solar procured to comply with the DSES.[24]

A. DG Solar Bundle Approach

Below, we discuss the history of the solar bundle model construct within our resource planning process, as well as the development of the solar bundles included in this IRP model.

1. Background

As indicated in Appendix E: Load and Distributed Energy Resource Forecasting and Appendix F: EnCompass Modeling Assumptions and Inputs, the projected growth of behind-the-meter distributed solar on the NSP System by 2050 is expected to be substantial.[25] This surge in adoption can be attributed to a multitude of factors, including the declining cost of photovoltaics, the maturity of the solar installation industry in Minnesota, and tax credits. Given that these factors are not under the

[24] *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. E999/CI-16-521.
[25] Residential solar growth is further discussed in the *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.

Company's control and that the decision to install behind the meter distributed solar systems lies with the customers rather than the utility, the Company has traditionally included this resource in the NSP system model as a fixed forecasted amount, rather than treating it as a generic, selectable resource. As a result, during capacity expansion planning, EnCompass will optimize the combination of various generic renewable and other resource options, but maintain a constant level of DG solar.

In the last IRP, the Distributed Solar Parties (DSP) presented an alternative modeling construct for behind-the-meter distributed generation. Instead of relying on the Company's fixed forecasted amount of DG solar in the capacity expansion optimization, the DSP proposed creating selectable "bundles" of distributed solar resources with varying cost points and MW capacity levels. EnCompass could then choose from these bundles, similar to the modeling constructs for DR and EE discussed in this appendix.

While most selectable options in EnCompass are modeled based on their levelized cost of energy (LCOE), the DSP argued that this was inadequate for residential and commercial solar behind-the-meter DG solar resources. This was because the LCOE represents the costs incurred by the customers, not the Company, for purchasing and installing a DG solar system. Instead, they contended that the Company could directly influence the adoption of DG solar by:

1. providing an additional incentive to make these systems economically attractive to more customers, thereby fostering predictably increased adoption, and
2. including only the incentive payment to participating customers as the cost represented in EnCompass for rooftop DG solar resources instead of the LCOE.

The DSP used an adoption model to estimate the expected MW capacity that customers would adopt under different incentive scenarios. This adoption model was based on the economics of DG solar from the perspective of the participating customer.[26]

The Company raised a few concerns in response to these options. The primary concern was the predictability of the actual amount of distributed solar capacity that the Company could bring online at a specific incentive payment level. While the DSP

[26] DSP adopted a model proposed by Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg in the journal Renewable Energy in December 2019. *See* Eric Williams et al., Empirical development of parsimonious model for international diffusion of residential solar, 150 Renewable Energy 570, 570- 577 (2020).

compared this construct to bundled approaches used for modeling EE and DR, it lacked any achievable potential analysis – an analysis of how much of an economically cost-effective demand-side resource can realistically be achieved given market and other barriers for customers and any utility resource limits. Achievable potential is an important and conventional component in implementing demand-side resources; indeed, the EE and DR resources modeled in this resource plan incorporate this aspect within their modeled resources.

We also raised concerns about whether this approach adequately accounts for potential rate and bill impacts, whether a significant portion of the payments might go to customers who would have installed such systems without a payment from the utility, and whether cost-effectiveness has been thoroughly evaluated from perspectives other than that of the participating customer when designing bundle levels.[27]

2. *Current Iteration of Proposed Modeling Construct*

For this IRP, we applied a "bundled approach" to demonstrate the modeling construct proposed by DSP. We discussed the proposed construct on three occasions with various interested parties. For additional information and recommendations, please see Appendix S: Stakeholder Engagement Summary, which contains more details on our correspondence and discussions on this matter.

3. *Adoption Model and Inputs*

Since this analysis involves working with multiple parties and examination of several assumptions, we used the same economic adoption model proposed by the DSP. This allows full transparency of the adoption model inputs used to create the bundles offered into EnCompass as well as transparency into key drivers, such as projected capital costs and the tax credits assumptions that impact the projected capacity of adopted solar.

The core principle of the adoption model brought forth by the DSP is that adoption can be modeled as a function of its economic viability for a participant. The model defined economic viability as the net present value (NPV) of the solar investment from the participant's perspective and forecasts the level. Essentially, a higher NPV makes the investment more attractive to customers. Fundamentally, the adoption model is designed to determine the appropriate "size" of the DG solar bundles that will be

[27] For example, a bundle with a very high incentive level, such as $90/MWH, would appear highly economic from the perspective of a participating customer but may not be cost-effective for the utility to implement.

offered in EnCompass as a selectable generation resource. As discussed below, the bundle sizes represent the amount of DG solar adoption that is economically viable at a given incentive level, pending a further assessment of achievable potential. Without a potential study to account for possible customer and implementation constraints, we do not have enough information to equate the amount of adoption projected by this model with the actual amount of solar that could be procured.

We used this same adoption model, with updated inputs as shown in Table J-3, to develop DG solar bundles for both commercial and residential customer classes.

Table J-3: Initial Year Input Assumptions for Economic Adoption Models[28]

Assumption	DSP's Residential Bundle in 2019 IRP	Residential Bundle	C & I Customer Bundle
Baseline Population	667,980 single family detached homes (7 county metropolitan area)	MSA is 15 counties MN and WI. 937,338 single-family detached homes	MSA is 15 counties MN and WI. 937,338 single-family detached homes
Size of typical installation	4 kWdc	7.2 kWdc	200 kWdc
Self-Consumption	100% (all consumed onsite)	100% (all consumed onsite)	100% on-site consumption
Gross Cost Per Watt	$3.50	$2.736	$2.049
Retail Price of Electricity	$0.12/kWh	$0.15/kWh	$0.13/kWh
Inflation Rate	2.00%	2.00%	2.00%
Lending Rate	5%	8%	8%
Capital Cost Subsidy (Federal)	Investment Tax Credit (ITC) expires in 2020	Inflation Reduction Act tax credits	Inflation Reduction Act tax credits
First Year Energy	5,000 kWh	8,311 kWh	236,528 kWh
Solar System Lifetime	25 years	30 years	30 years
Fixed Operations & Maintenance Costs	$0	$29.01/kW-yr	$18.08/kW-yr

[28] Many of the assumptions in Table J-3 change over the years. The assumptions for the initial year are provided in the table.

Assumption	DSP's Residential Bundle in 2019 IRP	Residential Bundle	C & I Customer Bundle
Additional Capital Cost Subsidy (Proposed Incentive Level Paid by Company)	$10/MWH, $20/MWH, $30/MWH, $35/MWH, $40/MWH	$10/MWH, $20/MWH, $30/MWH	$10/MWH, $20/MWH, $30/MWH

4. *What the Adoption Model Outputs Represent, and How They Are Used to Create Bundle Sizes*

Table J-3 above shows slight variations between input assumptions for the three different analyses conducted using the adoption model. In addition to differences in assumptions, there is a key difference in how the analysis in the last IRP and the analysis in this IRP would be implemented. Specifically, there is a difference in the assumptions about how the incentive levels analyzed in the adoption model would be used to acquire any DG solar bundles selected by EnCompass. In the 2019 IRP proceedings, the DSP proposed all incremental DG solar capacity receive the same incentive level as the highest bundle selected. In this Resource Plan, the amount of incremental solar receiving the incentive is capped at the amount of capacity projected in the solar adoption model. The capacity is targeted at DG solar that would not otherwise be installed without the incentive. This difference between the two IRPs, in which incentives are now assumed to be targeted at DG solar projects not already naturally occurring, was included in presentations to stakeholders on this construct and mitigates the Company's concern from the last IRP about the potential for substantial free ridership with this proposed modeling construct.

Once the adoption model provided by stakeholders produced the estimated MW levels for each of the proposed incentive levels, the residential and commercial adoption levels at a given incentive amount were bundled together. For example, for the year 2027, 3.8 MW of residential solar adoption and 4.4 MW commercial solar adoption were projected at an incentive of $10/MWH. Using the bundled approach, this means that EnCompass would be offered a single $10/MWH option for that year instead of separate residential and commercial DG solar bundles.

Finally, the bundles are composed of 5-6 year periods of acquisitions, instead of the 15 year periods that were proposed by the DSP in the last IRP. For example, Bundle 1 offers $10/MWH of incentive payments to customers installing new DG solar systems between 2024 and 2029, instead of the entire time period from 2024-2040. This was done to allow for contiguous years of consistent incentive level, which encourages customer participation without being locked into a long term bundle. This approach ensures that the cost of acquiring new solar in the 2030s does not exceed the price of new utility-scale solar during the same time horizon. Due to the declining price of utility scale solar, bundles with higher acquisition costs can be a cost-effective alternative to utility-scale solar in the 2020s but exceed the projected price of utility-scale solar in the 2030s. Providing bundles in 5-6 year segments instead of 15 year segments allows EnCompass to minimize the number of years in which this phenomenon occurs.

5. *Bundle Costs as Represented in EnCompass*

While each DG solar bundle directly adopts the MW size estimates generated by the adoption model, the cost assumption provided to EnCompass for each bundle is adapted to reflect administrative costs necessary for the utility to acquire DG solar from customers via incentive payments. This step is another key difference from the analysis put forth by the DSP in the last IRP, which did not assume any cost to the utility for acquiring solar resources directly from customers. Since EnCompass modeling involves generic acquisition assumptions, generic administration costs were generated for each bundle by using as a proxy at the same level of adminstrative budget relative to the entire estimated annual cost as is used for the residential and business segments in the ECO Triennial 2024 plan.[29] As further discussed below, if bundles are selected in EnCompass modeling, the actual costs would need to be determined through a subsequent analysis to assess whether the modeled amounts of DG solar are achievable. Such an analysis can also incorporate more granular procurement details, such as potential locations, project types, or customer segments to target.

6. *Bundles Provided in EnCompass Modeling*

The cost and size information from the adoption model analysis was used to develop the nine solar bundles shown below in Table J-4. The costs presented in this table include the proposed incentive payments modeled in the adoption model plus the previously discussed administrative costs.

[29] Decision, *In the Matter of Xcel Energy's 2024-2026 Energy Conservation and Optimization Triennial Plan*, Department of Commerce, December 1, 2023.

Table J-4: Solar Bundle Selectable Bundles Offered in EnCompass

Year	Bundles 1, 4, and 7		Bundles 2, 5, and 8		Bundles 3, 6, and 9	
	Incremental MW*	Acquisition Cost ($/MWH)	Incremental MW*	Acquisition Cost ($/MWH)	Incremental MW*	Acquisition Cost ($/MWH)
2024	9.86	$12.69	11.38	$25.37	13.09	$38.06
2025	9.17	$12.69	10.60	$25.37	12.22	$38.06
2026	8.58	$12.69	9.94	$25.37	11.49	$38.06
2027	8.08	$12.69	9.38	$25.37	10.86	$38.06
2028	7.66	$12.69	8.91	$25.37	10.33	$38.06
2029	7.30	$12.69	8.51	$25.37	9.89	$38.06
2030	7.01	$12.69	8.18	$25.37	9.53	$38.06
2031	6.77	$12.69	7.92	$25.37	9.23	$38.06
2032	6.59	$12.69	7.71	$25.37	9.00	$38.06
2033	5.98	$12.69	7.02	$25.37	8.22	$38.06
2034	5.48	$12.69	6.46	$25.37	7.58	$38.06
2035	3.43	$12.69	4.09	$25.37	4.85	$38.06
2036	3.21	$12.69	3.83	$25.37	4.55	$38.06
2037	3.00	$12.69	3.59	$25.37	4.28	$38.06
2038	2.83	$12.69	3.38	$25.37	4.04	$38.06
2039	2.67	$12.69	3.20	$25.37	3.83	$38.06
2040	3.43	$12.69	4.09	$25.37	4.85	$38.06
Cumulative Total By 2040[30]	96.4		112.8		63.4	

B. DG Solar Bundle Cost Categories

Costs associated with DG solar bundles impact various parties differently (i.e., participating customers who install solar systems realize costs and benefits that differ from those realized by the utility and non-participating customers). To address Order Point 15, in part, Table J-5 identifies the cost categories borne from each party's perspective. Costs stated here were not necessarily used in cost-effectiveness tests discussed below. Instead, they are presented to enable a more comprehensive evaluation when analyzing the achievable potential of DG solar bundles accepted in EnCompass modeling, as impacts will vary with program design, regulatory framework,

[30] Amount shown is incremental (new) DG solar installed each year. As with other solar resources in the EnCompass model, in each subsequent model year for the solar installed, a 0.5 percent annual degradation is assumed. The cumulative totals at the bottom of the table represent the total amount of solar offered into EnCompass by all bundles using the same level of customer incentive - $10/MWH, $20/MWH, or $30/MWH – inclusive of 0.5 percent annual degradation.

and local market conditions. The costs listed below were compared with cost categories used by other recent cost-effectiveness analyses of distributed solar.[31]

Table J-5: DG Solar Cost Categories

Cost Component	Description
Participating Customers	
Upfront Costs: Initial Solar Plant	Costs associated with purchasing and installation of solar system
Upfront Costs: Additional Distribution Upgrades	Any necessary upgrades to the distribution system for integration.
Ongoing Costs	Ongoing operation and maintenance costs during life of solar asset, including inverter replacement
Utility Or Non-Participating Customers	
Administration Costs (Labor Costs)	Costs related to administrative tasks such as program management and customer support.
Incremental Payments to Participating Customers	Payments made to participating customers as incentives or direct compensation for installing DG solar
Participating Customer Bill Reductions	Reduced revenues from reduced utility bills of participating customers. As noted further in the narrative this is not a net new cost to the system but cost shifts from these reductions can impact rates and/or bills for other customers.
Grid Technology Additions[32]	Investments in distribution grid infrastructure or technology to accommodate procured DG solar bundles.

[31] References include Benefits and Costs of Net Energy Metering in Washington. *Energy + Environmental Economics (E3)*. December 2023. Available at: https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefits-and-Costs-of-Net-Energy-Metering-in-Washington_2023-12-21.pdfand National Standard Practice Manual for Benefit Cost-Analysis of Distributed Energy Resources. August 2020. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[32] As noted in the Benefits and Costs of Net Energy Metering (December 2023), grid modernization investments, such as distributed energy resource management system (DERMS), are not generally associated with a specific increment of DERs such as DG solar and are instead made strategically to enable the utility to better manage both existing and anticipated DERs. As such, these costs may be incurred largely on behalf of resources such as DG solar but are typically recovered from all customers, thus resulting in a net cost to ratepayers.

Regarding the participating customer bill reductions listed in the table above, it is important to note that due to the structure of net metering, while not directly impacting the revenue requirement on the resource side of the ledger,[33] effectively reduces sales. This reduction in sales does not correspond with a proportional decrease in the costs that the Company continues to incur in serving the customer. Consequently, net metering leads to a disparity between sales revenue and ongoing service costs which can result in bill and/or rate impacts for other customers. While we have noted this cost in Table J-5, in accordance with the National Standard Practice Manual, we have not included it in the standard cost-effectiveness testing discussed below.[34] This is because it is more appropriately studied in more in-depth rate, bill, or participation analyses outside the scope of this generic IRP modeling.

C. DG Solar Bundle Cost Effectiveness Tests

The Company employed several cost-effectiveness tests to evaluate the DG solar bundles instead of relying upon the results of a single cost-effectiveness test. Tests included an analog to the Minnesota Cost Test, and as agreed upon by stakeholders, use of the standard cost-effectiveness tests used in many demand-side management cost-effectiveness analyses – the Participant Test, Ratepayer Impact Measure Test, Utility Cost Test, and the Societal Cost Test. All bundles passed the Minnesota Cost Test analog and were passed forward to EnCompass modeling.[35]

D. Other topics as identified by stakeholders to develop DG solar bundles modeling construct.

A comprehensive summary of stakeholder engagement is included in Appendix S. While no other topics were identified by stakeholders to develop the DG solar bundle modeling construct, stakeholder input informed the development of the solar bundles in this Resource Plan.

E. DG Solar Bundle Modeling Results and Next Steps

The results of this DG Solar Bundle modeling construct exercise are discussed in

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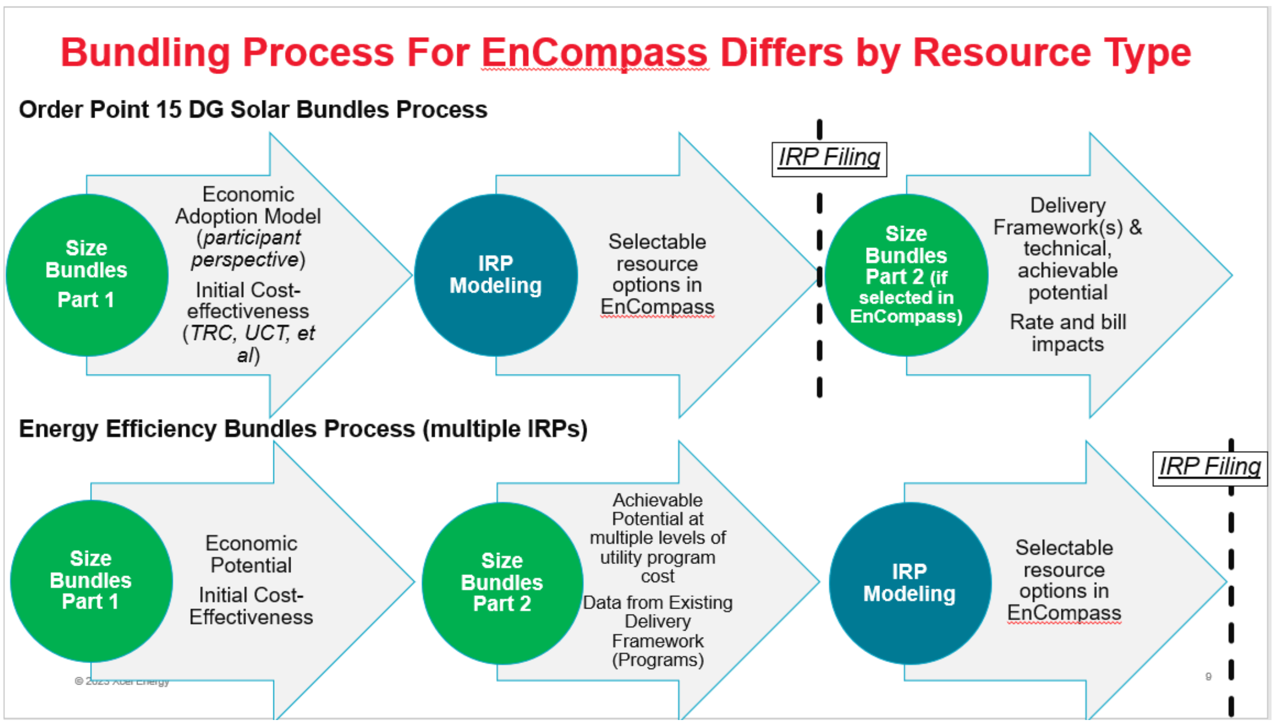
[33] In the parlance of terminology regarding cost-effectiveness testing, this means that retail bill savings from customers installing DG solar systems are not a net new cost to the system (i.e., there is no revenue requirement or new financial transaction that is included in the rate base).
[34] The only exception is the Ratepayer Impact (RIM) Test.
[35] For more information regarding the Minnesota Cost Test, see Decision, *In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Docket No. E,G999/CIP-23-46, March 31, 2023. (Further referred to as 2023 Cost-Effectiveness Decision).

Chapter 5: Economic Modeling Framework. As noted earlier, specific details on how these resources would be acquired, such as location, specific customers targeted, achievable potential, etc., fall outside the scope of this generic IRP modeling. These details would need to be identified, along with further cost-effectiveness testing updated with more granular inputs. Unlike EE and DR, the Company currently does not offer incentives for DG solar installations, outside of the Solar*Rewards program. Because of this different construct from EE and DR, additional analysis after bundle creation and EnCompass selection are necessary, as shown in the process comparison in Figure J-4 below.

Figure J-4: Summary of DG Solar and EE Bundle Processes



V. CONCLUSION

As noted above, DERs play an important role in our Resource Plan and are an essential part of our path towards carbon reduction. While the Company has a long history of integrating DERs into our system, advancements in technology will allow us to shift our efforts towards optimization of energy use, adding more value to the system.

Opinion Dynamics

Xcel Energy Northern States Power Company

demand management portfolio design Whitepaper

January 18, 2024

Introduction

Demand Response (DR) programs have been a part of energy planning for over 40 years. Over time, traditional DR has evolved in concert with the increasing availability of technologies unlocking breadth and depth of customer engagement, coupled with changing regulatory policies to address grid, customer, and climate needs. The last decade has marked an even more rapid evolution given the adoption of renewables, penetration of distributed energy resources (DERs), electrification policy objectives, and extreme weather events—creating a perfect environment to re-envision DR. As a result, new value streams have been unlocked, supplanting traditional DR with a more comprehensive approach: Load Flexibility.

This whitepaper explores the future opportunities and pathways to unlock the most value out of Load Flexibility in Xcel Energy's Northern States Power Company (NSP) service territory. To that end, the whitepaper addresses:

- The history of DR in the United States
- The state of DR programs and offerings in the Upper Midwest
- The evolution of Demand Response to Load Flexibility, including considerations to support NSP's future grid needs

Evolution of Demand Response in the United States

History of Demand Response in the United States

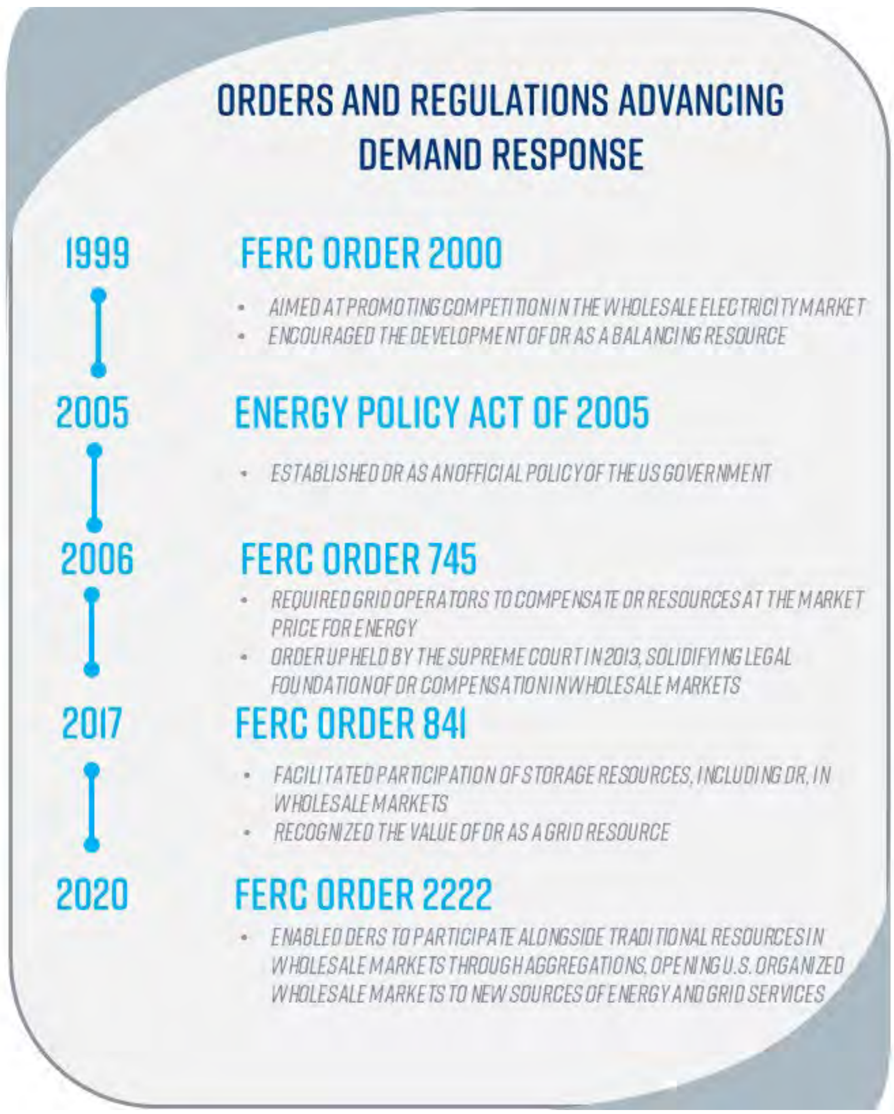
> *Demand Response is defined as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." – Federal Energy Regulatory Commission (FERC)*

Demand response (DR) programs originated in the 1970s and 1980s as utilities began to experiment with demand-side management (DSM) initiatives to tackle concerns about energy efficiency and peak demand.

The Energy Policy Act of 1992 was a significant milestone in the development of DR in the United States. It encouraged utilities to invest in energy efficiency and DR programs by allowing them to recover costs associated with these initiatives.

Beginning in 1999, a series of federal rules and orders established DR as a recognized resource in the wholesale markets (see sidebar). In response to regulatory signals and grid needs, DR programs have evolved significantly over time.

The advent and development of smart grid technologies facilitated better communication between utilities and consumers, which paved the way for more sophisticated DR programs.



DR Value Streams

This whitepaper focuses on value streams that are cost-effective for utilities to implement within the Upper Midwest, drawing from NSP's 2019 Potential Study associated with system peak demand. We acknowledge that additional value streams, such as affordability and carbon reduction, are not included in this framework (Hledik et al. 2019).

Table 1. DR Value Streams by Typology

DR Typology	Value Stream	Description
Traditional DR	Avoided generation capacity costs	Reduced need for new peaking capacity
	Reduced peak energy costs	Reduced load during high-priced peak periods
	System-wide deferral of transmission and distribution	Reduced need for peak-driven upgrades in transmission and distribution capacity
Non-Traditional DR	Geotargeted distribution capacity investment deferral	Targeted DR investments where load reductions would defer localized needs for capacity upgrades
	Ancillary services	Real-time adjustments to load from some end-use applications to mitigate system imbalances
	Load building/valley filling	Shifting on-peak load to off-peak hours
	Facilitating better integration of non-dispatchable, intermittent renewable generation resources	Adjusting load (up or down) as non-dispatchable renewables come online or go offline

Since 1970, DR programs have been evolving, albeit at varying timescales based on geographic, regulatory, and grid features. This evolution is classified broadly into three phases: DR 1.0 – The Past, DR 2.0 – The Present, and DR 3.0 – The Future, which align with an increasing array of value streams.[1]

DR 1.0 – The Past

- The earliest DR programs were interruptible tariffs (manual dispatches for large commercial and industrial [C&I] customers and one-way communication load control devices for residential customers).
- DR was primarily used to provide energy and/or capacity when wholesale prices were unusually high, there was a shortfall in generation or transmission capacity, or during unexpected emergency grid operating situations. Notifications were manual, and there was little to no customer feedback on performance.[2]
- Activities focused on demand reductions during a limited peak window for a small number of hours per year with the following associated value streams: generation capacity avoidance, reduced peak energy costs, and system peak-related transmission and distribution deferral (Faruqui and Hledik 2018).

DR 2.0 – The Present

- DR became integral to most wholesale markets and grid operation systems in the US. DR provided more precise energy and capacity to support wholesale marketplace activities, as well as sophisticated and near real-time measurements, which were often used as the system of record for customer feedback and confirmation of customer performance.
- Program variety increased, alongside increasing automation and program sophistication (e.g., transition of air conditioning switch programs to smart thermostats, C&I programs that extend beyond simple interruptible tariffs [e.g., demand bidding, performance-based payments], exploration of DR potential among small businesses, EV-managed charging programs, etc.).

[1] The descriptions of DR 1.0, 2.0, and 3.0 are informed by the authors' industry experience as well as their role facilitating Peak Load Management Alliance's "The Evolution of DR to DER" training class.
[2] NSP's traditional event-based DR (DR 1.0) is dispatched in response to emergency events called by MISO and does *not* refer to participation in MISO's day-ahead or real-time energy markets.

- Communication signals improved, which contributed to DR program variations.
- Adoption of advanced metering infrastructure (AMI) created additional DR program options, such as behavioral DR, critical peak pricing, and peak time rebates.
- DR timing moved beyond event-window peak shaving to the potential for 24/7 continuous management, and existing programs increasingly focused on targeted distribution capacity deferral.

DR 3.0 – The Future

- DR will be characterized by greater complexity.
- DR (or the DR 3.0 paradigm of "Load Flexibility") will evolve to be a component of broader distributed energy resources (DERs), including distributed photovoltaic (PV), EV charging, and various forms of energy/thermal storage, both on a grid operating system scale as well as behind-the-meter (i.e., on the customer side of the meter).

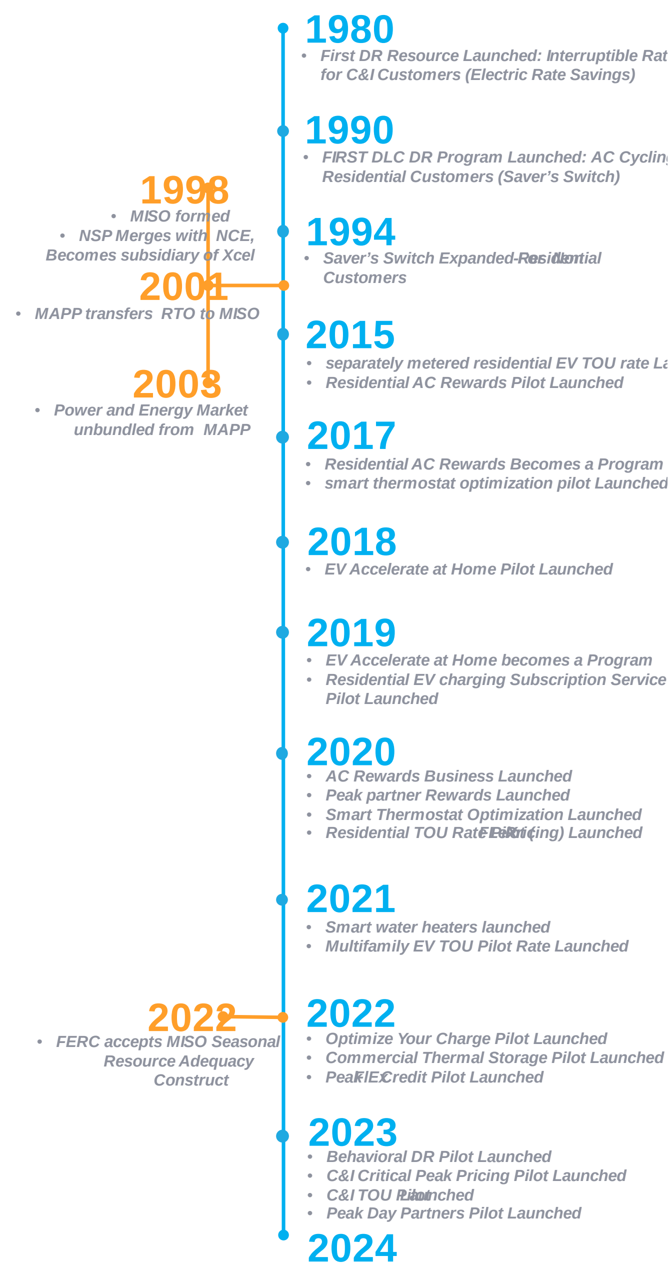
Load Flexibility is defined by the California Energy Commission as "the practice of adjusting load (or energy usage) to match the supply of electricity."

- Where wholesale markets exist, the major underlying economic principle of DR is a price signal, which moves the industry away from traditional "command-and-control" mechanisms to manage grid operations. In DR 3.0, Load Flexibility is not necessarily triggered directly by the utility or by the system operator; rather, dynamic loads can also be modified automatically via devices that react to pre-programmed price thresholds, although prices do not always trigger a DR signal. Utilities can also rely on a grid signal, such as voltage, rather than a price signal for emergencies and system peaks.
- DR can provide a variety of service benefits to customers and grid operators. Customers may even be "prosumers" who both provide and consume grid power, including volt/var control, renewable energy integration, and localized distribution system congestion management.
- Importantly, a broader definition of DR (including behavioral, EV, grid-interactive water heating, battery storage, etc.) across an 8760-time scale can unlock additional value streams (e.g., valley filling/load building and ancillary services). Lawrence Berkeley National Laboratory's landmark 2017 study put forth a novel framework for classifying Load Flexibility resources into four distinct "service types": Shape, Shed, Shift, and Shimmy. This work standardized nomenclature around these various Load Flexibility value streams, effectively replacing the historic monolithic concept of event-based DR with a more nuanced Load Flexibility framework.
- Many Load Flexibility value streams have not been established or quantified yet, though efforts are well underway, and opportunities abound. Most of the efforts across the country are nascent, with pilots showing promising results.

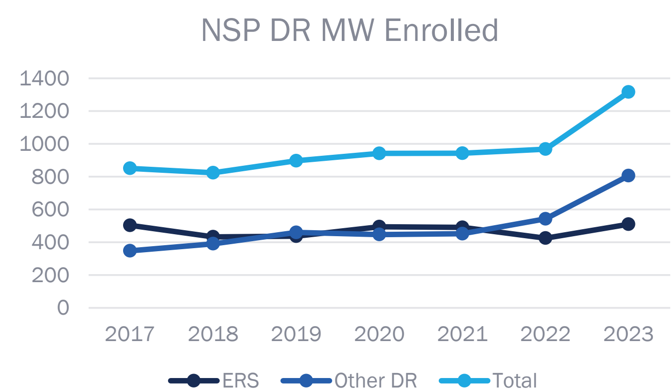
The State of DR Programs and Offerings in the Midwest

Xcel Energy: Northern States Power Company

NSP's history with DR began in 1980 with the launch of Electric Rate Savings (ERS). Over the next decade and a half, NSP launched two other flagship DR programs: Saver's Switch programs for both residential and non-residential customers. These legacy DR programs constitute over three-quarters of NSP's current DR potential. Notably, these DR 1.0 programs were developed under a different market construct (the Mid-Continent Area Power Pool, or "MAPP") than the current wholesale markets operated in the region through the Midcontinent Independent System Operator, Inc. (MISO).



Xcel Energy NSP has rapidly expanded its DR offerings in Minnesota in recent years, deploying at least one new pilot or program every year since 2017, including the launch of three new Load Flexibility pilots in 2022. Since 2017 alone, NSP acquired an additional 482 MW of capacity.[3]



NSP's current DR portfolio spans a variety of end uses and load modification strategies. Accordingly, Xcel Energy's efforts to expand its DR portfolio in Minnesota have contributed to steady inclines in flexible MW potential (see chart of MW Enrolled). These new offerings have resulted in net increases in DR potential despite declining MW enrollments in ERS (NSP's largest single source of DR potential). Per NSP's forthcoming DR Compliance Filing to the Minnesota PUC: "In total, the Company now has 14 percent of its peak demand available for demand response control across its Northern States Power Company jurisdictions. This includes active enrollment of approximately 460,000 residential and small business customers and 19,000 commercial and industrial customers in

[3] As of publication, this value has yet to be externally published. This value is forthcoming in the same docket referenced in the prior DR Compliance Filing (Northern States Power Company 2023a).

demand response programs" (see Table 2).[4] These enrollment numbers suggest that traditional DR enrollment rates may be approaching saturation. Based on findings from Brattle's 2019 Potential Study cited in NSP's last Integrative Resource Plan (IRP), opportunities to further grow NSP's traditional DR potential may be limited, as "the market for traditional cost-effective DR in MN may be approaching saturation" resulting in enrollment plateaus (Hledik et al. 2019). As of 2023, NSP achieved 1,316 MW of DR resources; exceeding the identified 2023 potential of 1,143 MW referenced in Hledik et al. 2019.[5] Thus, expanding non-traditional load flexibility is necessary to enable the subsequent growth of NSP's DR portfolio. Accordingly, NSP will need to pursue additional program offerings to exceed the MW and customer enrollment plateau that NSP may be very close to meeting. As a result, exceptional customer engagement and satisfaction will be essential to ensure existing legacy programs maintain customer enrollment.

[4] As of publication, these values have yet to be externally published. These values are forthcoming in the same docket referenced in the prior DR Compliance Filing (Northern States Power Company 2023a).

[5] Cost-effectiveness results for some newer DR resources are still pending, as many of NSP's new DR offerings are still in the pilot phase.

Table 2. Total MW Enrolled by Customer Class

Customer Class	Program	Description	Launch Year	Eligibility	Participants Enrollled (2023)	MW Enrolled (2023)	MW Enrolled: Fraction of Total (2023)
Residental	Residential DR: *Saver's Switch* *AC Rewards* *Smart Water Heaters*	Switch or smart thermostat AC direct load control program and water heater direct load control program	*Saver's Switch:* 1990 *AC Rewards:* 2015 *Smart Water Heaters:* 2021	Residential customers with central AC systems or heat pump water heaters	458,347	542	41%
	EV Optimization Pilot	Will study the management of the grid impacts of electric vehicles by working with customers to provide schedule options for their daily EV charging. The schedule options ensure charging occurs outside the Company's system peak and are designed to stagger charging times to avoid demand spikes during the off-peak period.	2022	Residential customers charging an electric vehicle at a residential address. Must use eligible equipment or drive an eligible vehicle.	1,337	2	0.2%
Commercial / Industrial	Electric Rate Savings	Demand charge discount for reducing load by at least 50 kW during control periods	1980	Business customers capable of reducing load by >50 kW	1,886	510	39%
	Peak Partner Rewards	Bill credit for reducing demand by at least 25 kW during control periods	2021	Business customers who contract to reduce demand by ≥25 kW	82	20	2%
	Commercial AC Control: *Saver's Switch* *AC Rewards*	Switch or smart thermostat direct load control program	*Saver's Switch:* 1994 *AC Rewards:* 2020	Commercial customers with central AC systems	16,807	138	10%
	EV Optimization Pilot	Will study the management of the grid impacts of electric vehicles by working with customers to provide schedule options for their daily EV charging. The schedule options ensure charging occurs outside the Company's system peak and are designed to stagger charging times to avoid demand spikes during the off-peak period.	2022	Busines customers charging an electric vehicle at a business address. Must use eligible equipment or drive an eligible vehicle.	8	0	0%
	Peak Flex Credit Pilot	Dispatchable, load-shedding program for commercial customers that provides additional flexibility and optionality to customers who want to design program parameters to work within their operational and business needs. This pilot provides pricing for both peak control events as well as buy-through options for economic control events and includes a tranche of load intended for third-party aggregation.	2022	Business customers capable of reducing load by 50 kW	4	4	0.3%
	Critical Peak Pricing Pilot	Pilot will study new time-varying rate design for a number of commercial and industrial customers. Features a three-part rate that incorporates energy and demand charges into a single volumetric rate. This rate also features a critical peak pricing component, where the Company calls events during times of extreme system peak. This pilot is paired with the General Time of Use Pilot above and is intended to inform the future design of commercial and industrial rates.	2023	Business customers with demand ≥50 kW over the preceding 12 months and with a load factor ≥30% over last 12 months	5	1	0.1%
	Peak Day Partners Pilot	The Peak Day Partners pilot program will offer commercial and industrial customers an incentive through an incentive bidding process, in exchange for reducing their peak load during periods when demand is high. The product purpose is to provide the Company with an additional power purchase resource to manage system requirements more efficiently during exceptional periods, and the Customer the option of receiving pricing associated with energy supply markets during such periods.	2023	Business customers capable of reducing load by 500 kW	37	99	8%
Totals	**All Programs**	**N/A**			**478,513**	**1,316**	**100%**

NSP's DR portfolio growth reflects the planning value that DR brings. Specifically, DR contributes to NSP's resource adequacy (RA) needs and helps ensure that NSP has a sufficient reserve margin (RM) for safe, reliable, and resilient operations. Grid and economic conditions over the last few years have not typically required frequent dispatch of DR resources to meet NSP's peak capacity needs. Nonetheless, NSP's current DR potential is essential to maintain the requisite RA and RM.

Additionally, NSP may be able to realize new value streams going forward, such as emergency and distributional value streams (the latter of which do not necessarily align with traditional MISO value streams). Additionally, MISO's new seasonal construct can potentially provide non-summer avoided generation capacity value for NSP. Accordingly, NSP has been expanding its winter DR capability, first by testing winter events in ERS in 2017 and later actively dispatching more frequently during the 2023/2024 winter season.

A comparison of independent system operators (ISOs)/regional transmission organizations (RTOs) reveals the regionally specific nature of DR value streams. Whereas neighboring PJM has a formal capacity market where load serving entities (LSE) can bid DR into the market, DR in MISO is used as a planning tool and for emergency response. Specifically, a LSE's DR resources can be used to meet MISO's annual capacity requirement and reserve margins (Sustainable FERC Project 2024a). These DR resources may then be dispatched in response to emergency events called by MISO. Conversely, DR is *not* dispatched or bid into MISO's day-ahead or real-time energy markets. Like MISO, CAISO also lacks a formal capacity market but has mandatory resource adequacy requirements (Sustainable FERC Project 2024b). Accordingly, other markets may offer more cost-effective DR 3.0 opportunities for their constituent LSEs than the value streams found in MISO.

An examination of capacity clearing prices and wholesale energy prices also exposes significant variation across ISOs/RTOs. For example, MISO's North/Central zones (which include NSP's operating territory) had capacity clearing prices at $15/MW-Day or lower in the 2021/2022 and 2023/2024 Planning Resource Auctions (PRA), whereas the 2022/2023 PRA clearing price was $236.66/MW-Day (15+ times higher) due to capacity shortfalls in four zones during that PRA cycle. PJM capacity prices have also experienced significant variation during that timeframe, ranging from $34.13/MW-Day in the recent 2023/2024 auction to $140/MW-Day in the 2021/2022 auction. Excluding the aberrant MISO clearing price spike in 2022/2023, PJM had higher capacity clearing prices than MISO in the past few auction cycles. CAISO, on the other hand, experienced less variation but had consistently high capacity prices over the last three years, with capacity prices ranging from $215.01/MW-Day to $227.84/MW-Day.[6] Locational Marginal Prices (LMP) for energy expose additional variation, with CAISO demonstrating notably different LMP trends than both MISO's North/Central hubs and PJM (which share more comparable LMP trends). When assessing example winter and summer days between the three ISOs/RTOs, CAISO consistently has the highest day-ahead prices, as well as the largest price swings within a given day.

Benchmarking against other utilities in the region

Based on a review of DR portfolios in the Upper Midwest, we found that NSP's DR program deployment is on par with investor-owned utilities the region. In general, we found that these portfolios reflect the value streams that are accessible given the market. Specifically, they are all summer peak-focused, and pilot activities are emergent (such as time-varying rate solutions). Across the Midwest, nascent efforts are underway to test DR applications beyond capacity in preparation for the transition to the Load Flexibility paradigm. The following two pages demonstrate how NSP's DR portfolio compares to other utilities in the Upper Midwest.

[6] CAISO reports capacity prices in $/kW-month. Values referenced in this paper have been scaled to reflect reporting units used in MISO and PJM ($/MW-day).

		RESIDENTIAL									COMMERCIAL AND INDUSTRIAL								
	UTILITY	AC CYCLING	SMART TSTAT DLC	WATER HEATER DLC	SPACE HEATING DLC	EV DR	OTHER DEVICE DLC	BEHAVIORAL DR	TIME-OF-USE RATE	CRITICAL PEAK PRICING RATE	AC CYCLING	WATER HEATER DLC	SPACE HEATING DLC	OTHER DEVICE DLC	CUSTOMER NOMINATED CURTAILMENT	INTERRUPTIBLE RATE	TIME-OF-USE RATE	CRITICAL PEAK PRICING RATE	REAL-TIME PRICING RATE
	Xcel Energy Minnesota	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	
MICHIGAN	Alpena Power Co.								✓							✓	✓		
MICHIGAN	Consumers Energy	✓	✓			✓		✓	✓						✓	✓	✓		
MICHIGAN	Detroit Edison Co.	✓	✓	✓		✓			✓	✓						✓	✓	✓	
MICHIGAN	Indiana Michigan Power	✓	✓	✓		✓		✓	✓	✓	✓				✓	✓	✓	✓	
MICHIGAN	Upper Peninsula Power Co.															✓		✓	✓
MICHIGAN	Wisconsin Electric Power Co.	✓		✓					✓		✓	✓			✓	✓	✓		✓
MICHIGAN	Wisconsin Public Service Corp.	✓		✓					✓		✓	✓				✓	✓		
MINNESOTA	Minnesota Power			✓	✓	✓	✓		✓			✓	✓	✓		✓			
MINNESOTA	Northwestern Wisconsin Electric Co.			✓	✓				✓								✓		
MINNESOTA	Otter Tail Power Co.	✓		✓	✓	✓	✓				✓	✓	✓	✓			✓		
NORTH DAKOTA	Montana-Dakota Utilities Co.				✓				✓						✓	✓	✓		
NORTH DAKOTA	Otter Tail Power Co.	✓		✓	✓		✓				✓	✓	✓				✓		

RESIDENTIAL

	UTILITY	AC CYCLING	SMART TSTAT DLC	WATER HEATER DLC	SPACE HEATING DLC	EV DR	OTHER DEVICE DLC	BEHAVIORAL DR	TIME-OF-USE RATE	CRITICAL PEAK PRICING RATE
	Xcel Energy Minnesota	✓	✓	✓	✓	✓	✓	✓	✓	
MICHIGAN	Alpena Power Co.								✓	
MICHIGAN	Consumers Energy	✓	✓			✓		✓	✓	
MICHIGAN	Detroit Edison Co.	✓	✓	✓		✓			✓	✓
MICHIGAN	Indiana Michigan Power	✓	✓	✓		✓		✓	✓	✓
MICHIGAN	Upper Peninsula Power Co.									
MICHIGAN	Wisconsin Electric Power Co.	✓		✓					✓	
MICHIGAN	Wisconsin Public Service Corp.	✓		✓					✓	
MINNESOTA	Minnesota Power			✓	✓	✓	✓		✓	
MINNESOTA	Northwestern Wisconsin Electric Co.			✓	✓				✓	
MINNESOTA	Otter Tail Power Co.	✓		✓	✓	✓	✓			
NORTH DAKOTA	Montana-Dakota Utilities Co.				✓				✓	
NORTH DAKOTA	Otter Tail Power Co.	✓		✓	✓		✓			

COMMERCIAL AND INDUSTRIAL

	UTILITY	AC CYCLING	WATER HEATER DLC	SPACE HEATING DLC	OTHER DEVICE DLC	CUSTOMER NOMINATED CURTAILMENT	INTERRUPTIBLE RATE	TIME-OF-USE RATE	CRITICAL PEAK PRICING RATE	REAL-TIME PRICING RATE
	Xcel Energy Minnesota	✓	✓	✓	✓	✓	✓	✓	✓	
MICHIGAN	Alpena Power Co.						✓	✓		
MICHIGAN	Consumers Energy					✓	✓	✓		
MICHIGAN	Detroit Edison Co.						✓	✓	✓	
MICHIGAN	Indiana Michigan Power	✓				✓	✓	✓	✓	
MICHIGAN	Upper Peninsula Power Co.						✓		✓	✓
MICHIGAN	Wisconsin Electric Power Co.	✓	✓			✓	✓	✓		✓
MICHIGAN	Wisconsin Public Service Corp.	✓	✓				✓	✓		
MINNESOTA	Minnesota Power		✓	✓	✓		✓			
MINNESOTA	Northwestern Wisconsin Electric Co.							✓		
MINNESOTA	Otter Tail Power Co.	✓	✓	✓	✓			✓		
NORTH DAKOTA	Montana-Dakota Utilities Co.					✓	✓	✓		
NORTH DAKOTA	Otter Tail Power Co.	✓	✓	✓				✓		

Load Flexibility Transition

DER National Trends

Deployment of DERs has increased nationwide in recent years and is anticipated to continue increasing in the future. The most common DERs include solar and wind, combined heat and power, energy storage solutions, load-modifiable end uses (such as smart thermostats or EVs), as well as microgrids and nanogrids. DERs are frequently grouped into three main categories: demand (e.g., EV chargers, smart thermostats paired with HVAC systems), storage (e.g., behind-the-meter storage and EV batteries), and generation (e.g., solar and wind). The various DERs have differing effects on the grid, and each presents unique DR and Load Flexibility opportunities.

Over the last three years, the US installed over 40 GW of solar PV, fueled largely by the steep and ongoing decrease in the prices of solar modules and inverters, as well as extended federal tax credits (Solar Energy Industries Association 2023).

According to Bloomberg NEF's annual battery price survey, battery prices (including both behind-the-meter and utility-grade) have also been declining for several years and experienced a 14% drop from 2022 to 2023, reaching a record low of $139/kWh due to falling raw material and component prices.

The US energy storage market installed a record 4.8 GW in 2022, with installations expected to reach almost 63 GW between 2023 and 2027 (Wood Mackenzie Power 2023). In Q3 2023, grid-scale storage deployment in the US grew by 52% over the previous year from 4.5 GW to over 6 GW. Distributed storage is expected to grow twice as fast as grid-scale (Wood Mackenzie Power and Renewables/American Clean Power 2023).

Over the last few years, EVs have emerged as a formidable DER. Due to the decreasing manufacturing costs of electric vehicle batteries, along with improvements in the driving range of electric vehicles and supportive policies from corporate, state, and federal governments (such as the Corporate Average Fuel Economy standards, Clean Vehicle Credits enacted by the Inflation Reduction Act [IRA], and the Clean Air Act), the market share of light duty EVs has increased exponentially. In 2023 alone, over 1.2 million EVs were sold in the US, representing over 8% of all light-duty vehicles. In comparison, over 4.5 million EVs have been sold in total since 2010. Myriad efforts are underway to understand EV Load Flexibility through rate-based solutions and managed charging programs (Argonne National Laboratory 2023). Efforts are springing up across the country to test the vehicle-to-grid (V2G) and vehicle-to-home (V2H) capabilities of EVs.

Each year from 2025 to 2030, the US grid is expected to add 20–90 GW of nameplate demand capacity from EV charging infrastructure and 300–540 GW of nameplate storage capacity from EV batteries, an additional 5–6 GW of flexible demand from smart thermostats, water heaters, and non-residential DERs, 20–35 GW of nameplate generation capacity from distributed solar and fuel-based generators, and 7–24 GW of nameplate storage capacity from stationary batteries.

Building electrification goes hand-in-hand with transportation electrification. With significant potential to mitigate emissions and decarbonize energy supply chains, building electrification has been on the rise in the US. More specifically, the percentage of US homes heated with electricity has increased steadily from 1% in 1950 to 40% in 2020, and the electrification trend continued to intensify, fueled by favorable state and federal policies (Davis 2022). Between 2022 and 2023, multiple states have passed major new laws promoting clean heating through fuel switching (Minnesota Energy Conservation and Optimization Act, Illinois Climate and Equitable Jobs Act, and the Colorado SB21-246, among many others), and IRA legislation offers a suite of financial incentives to encourage individuals and businesses to invest in clean, efficient alternatives for their homes and businesses (Smedick, Golden, and Petersen 2022). For example, in 2022, heat pumps outsold fossil fuel-based heating systems in the US.

Forecasted estimates across the industry for DER penetration consistently predict the addition of more varied resources to the grid as well as the increasing complexity of resources interacting with one another. These interactions are made possible by the emergence and growth of smart grid and building technologies, ranging from smart thermostats to complex Virtual Power Plants (VPP) capable of aggregating and orchestrating multiple DERs in an automated environment.

FERC Order 2222 allowed the participation of VPPs in wholesale markets. While the implementation of the order is ongoing across the wholesale markets, as of August 2023, two out of six FERC-jurisdictional ISOs/RTOs allowed participation from VPPs that inject electricity for at least a subset of grid services. Texas also began opening the Electric Reliability Council of Texas (ERCOT) market to VPPs.

Xcel defines VPPs as: "an aggregation of controllable DERs managed at a scale that provides grid services or attributes, including energy and negative energy, ancillary services, and capacity. DERs aggregated to create a VPP could be utility or customer owned, in-front or behind the meter. DER assets in a VPP could include, but are not limited to, photovoltaic solar, energy storage, electric vehicles, and demand-responsive devices such as water heaters, air conditioning units, thermostats, and appliances. A VPP has benefits, such as the ability to deliver peak load electricity or load-following power generation on short notice. Such a VPP could replace a conventional power plant while providing higher efficiency and more flexibility, which allows the system to react better to load fluctuations. Resources that are part of a VPP may also be able to provide local grid benefits (to the extent that the resources are in close proximity to a local constraint) such as reducing loading on a distribution feeder" (Northern States Power Company 2023b).

Utilities across the country are pursuing price signals to better manage DERs—and demand in general—in the form of time-varying rates. Some states, like California, opted for a broad TOU defaulting approach, while others, like Oregon, are pursuing a targeted exploration of load-shifting capabilities of time-varying rates. Regardless of approach, across the country, time-varying rates are moving from the periphery to the mainstream of electricity pricing, fueled by the adoption of AMI technology. The arc of price responsiveness shows great promise in the ability of time-varying rates to support flexible load management (Faruqui and Tang, 2023).

The Department of Energy (DOE) Grid-Interactive Efficient Building Initiative fueled the development of roadmaps, frameworks, and pilots to test smart building technologies capable of grid integration (Office of Energy Efficiency & Renewable Energy 2023). While VPPs are not new and have been operating with commercially available technology for years, they have become an emerging solution in recent years, capable of aggregating DERs and contributing to resource adequacy at a low cost. VPPs deliver economic benefits, increase resiliency, offer carbon and other benefits, reduce T&D congestion, and empower communities. While integration of VPPs into electricity system planning, operations, and market participation has been limited to date, studies of VPPs across the country point to their strong potential to deliver value to both the bulk power system as well as distribution system in vertically integrated and restructured energy market environments.

The growth of DERs is fundamentally reshaping the electric industry and making the operation of the grid considerably more challenging as more DERs are added. However, DERs can also offer a tremendous amount of additional flexibility for meeting load needs throughout the day, month, and year, thus opening new value streams for utilities to leverage. As such, Load Flexibility is increasingly important to ensure that the adoption of DERs and renewables is orchestrated effectively and efficiently.

From DR to Load Flexibility

In the context of growing DERs and grid-edge solutions, such as VPPs and grid-integrated buildings, the traditional event-based paradigm of DR is evolving into a Load Flexibility paradigm. Within this paradigm, electricity consumption is managed in increasingly granular units of time to address economic and system reliability conditions. California and New York were among the first states to pioneer Load Flexibility by instituting regulatory paradigms and roadmaps for integrating DERs. In California specifically, the Energy Division of the California Public Utilities Commission (CPUC) released a white paper and a proposal aiming at bringing together disparate baskets of flexible load solutions into a unified load management signal (Phillips 2022) (Madduri et al. 2022).

Other parts of the country are dipping their toes into the world of DER integration by piloting VPPs and innovative flexible load pilots. The efforts are still nascent and exploratory, seeking to properly assess the potential and ascertain value streams. We selected three distinct examples to demonstrate a cross-section of innovative flexible load initiatives across the country. For more information on these examples, see Appendix A.

Renewable Battery Connect Program
Public Service Company of Colorado

Sector
Residential/small business

Load Control Strategy
Solar Charged Battery Discharge

Dispatch Timing
Any time of year, Typically afternoons/evenings of the hottest days of the year

Participant Eligibility
Single-family homes/small businesses with solar and newly installed tesla powerwall or Solaredge home hub inverter with solaredge home battery

Enrollment
Opt-In

Participant Count
65 customers with 90 Batteries, 200 additional applications in Queue

DR Potential
Current: 0.73 MW
Goal: 10 MW (by end of 2025)

Peak Power Rewards Program
Pacific Gas & Electric

Sector
Residential

Load Control Strategy
Battery Discharge

Dispatch Timing
Everyday 7 p.m. to 9 p.m. from August to October

Participant Eligibility
Single-family homes with Sunrun solar systems and LG Chem/Solaredge/Tesla Powerwall battery

Enrollment
Opt-out

Participant Count
8,500 customers

DR Potential
34 MW

Multifamily Water Heater Pilot
Portland General Electric

Sector
Multifamily

Load Control Strategy
Water Heater curtailment

Dispatch Timing
Non-holiday weekdays, Timing dependent on grid needs, typically summer evenings and winter mornings/evenings

Participant Eligibility
Multifamily properties with at least 50 individually metered units and 30-50-gallon electric resistance water heaters

Enrollment
Opt-In

Participant Count
13,000+ switches

DR Potential
Summer: 2.4 MW Winter: 4.5 MW

Planning the Transition in Xcel Energy's service territory

Emerging Trends

According to the 2019 NSP Potential Study conducted by the Brattle Group, "NSP's cost effective opportunities to date have been constrained by limitations of the metering technologies, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and the relatively high cost of emerging DR technologies" (Northern States Power Company 2019, Appendix G2). However, this equation has begun to change since that study was published: AMI deployment is anticipated to be finished by the end of 2025 and a capacity shortfall is now anticipated as of 2027 (Northern States Power Company 2023c). In the short term, NSP does not foresee distribution system challenges that can be addressed by DR or Load Flexibility alone. The price signals associated with additional value streams for DR, such as ancillary services, have not historically fueled further growth of DR resources in NSP territory.

These legacy limitations and nuances historically shaped the value streams and available applications of NSP's existing DR programs. A substantial portion of the value of NSP's DR resources to date has been avoidance of load-supporting generation. As a result, the design of NSP's DR programs focused on supporting event-based peak shaving as opposed to continuous load management.

Nonetheless, the growth and proliferation of DERs, as well as the evolution of DR to Load Flexibility, is occurring in Xcel Energy's NSP service territory alongside the rest of the nation. The nuances of the service territory's forecasted generation mix, customer composition, and energy market shape a unique evolution trajectory with a distinct set of needs and potential solutions.

Renewable resources, including wind, solar, hydropower, and biomass, generated the largest share of Minnesota's electricity in 2022. In 2022, wind provided 23% of Minnesota's total in-state electricity net generation, and solar provided 4%. Minnesota's mandatory renewable energy portfolio standard (RPS) requires that the state's electricity providers generate or procure at least 25% of their electricity retail sales from eligible renewable sources by 2025, apart from the state's largest utility, which must meet an even higher standard. Xcel Energy seeks to generate all power from carbon-free energy resources by 2050 (Xcel Energy 2023). In 2018, the state's utilities had already met the 25% requirement. There is an additional goal that 10% of statewide electricity sales come from solar power by 2030.

Minnesota's population is poised for significant growth, with the Minnesota State Demographic Center forecasting that the state will gain 850,000 new residents between 2020 and 2070, a 15% increase from 2020 levels. Steady predicted urbanization of the population will lead to a declining population in two-thirds of Minnesota's 87 counties (Minnesota State Demographic Center 2023).

Minnesota, similar to the rest of the Midwest, has historically been a summer-peaking region. However, the growing adoption of renewable generation sources,[7] including solar and wind, is poised to change the value of DR. Increasing solar generation during the day is highly coincident with the summer peak and will likely reduce the value of DR during that period. At the same time, heavier reliance on renewable generation has the potential to shift net system peaks to different times of the day, thus creating potential curtailment needs at different times of the day, season, and year. DR program designs focused on existing summer peaking hours might not translate in a similar fashion to other days of the week or hours of the day in other seasons. For instance, NSP's largest residential program focuses on curtailing air conditioning load, which is not suitable for the shoulder or winter seasons and may not result in the same customer

[7] Growth in renewables is necessary to meet the Minnesota Legislature's mandate of a 100% carbon-free standard for electric utility generation and procurement by 2040.

engagement or curtailment potential during later hours in summer days. Renewable energy is intermittent, and heavier grid reliance on renewable energy sources can contribute to price volatility, which can create a need for high-value grid balancing services, such as frequency regulation, making DR a more viable solution.

On August 31, 2022, FERC accepted MISO's proposal to move to seasonal resource adequacy requirements rather than a single requirement based on the summer peak. MISO proposed this seasonal resource adequacy construct to address significant increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, outages resulting from extreme weather events, and declining excess reserve margin. MISO implemented the new seasonal resource adequacy construct in the Planning Resource Auction held in April 2023.

While Minnesota is currently a summer peaking region, building and transportation electrification trends are projected to create peaking conditions during non-summer seasons in Minnesota and throughout the Midwest. NREL forecasts Minnesota to exceed half a million EVs by 2030. Growing transportation electrification load is poised to impact both bulk power and distribution systems, opening pathways for additional opportunities for Load Flexibility solutions. The Midwest wind resource peaks in spring and fall, while solar peaks in summer. Growth of electric heating load in the winter could create new peaks and open opportunities for winter DR.

NSP started AMI deployment in 2022. As of September 2023, over 500,000 meters were installed, and the deployment is set to complete the rollout of the AMI infrastructure in 2025 (Northern States Power Company 2023b). AMI is a key element of the modern grid and can open the doors to the emergence of load management through time-varying rates. Like the rest of the country, Minnesota and the rest of the Midwest experienced rapid emergence of storage as well as enabling technologies, such as smart thermostats, smart appliances, and commercial load control automation tools. Notably, Xcel Energy's Grid Modernization plan includes leveraging distributed energy resource management system (DERMS) strategy and assessment in the short term and increasing focus on EV pilots, infrastructure, and energy storage in the short-to-longer term. These technologies expand the possibilities for DR to extend beyond the peak shaving service to achieve Load Flexibility. Projected future enabling technologies cost declines will likely enable increased adoption of the technologies. At the present time, however, these emerging technologies have yet to experience meaningful cost declines, integration, and communication protocols have yet to be tested and confirmed, and customer comfort has yet to be deepened. Furthermore, cost recovery avenues will need to evolve to support the integration of the enabling technologies. Cost recovery for demand management programs under the prior Conservation Improvement Program (CIP) rider was challenging.[8] However, recent revisions to Minnesota State Statutes enhance utility cost recovery for "load management activities," thereby opening the door for additional Load Flexibility opportunities. Customer adoption and engagement are important to consider as well. Integration of DERs and continuous management of demand will require a different customer engagement and incentive structure from the more traditional incentive structures aligned with the limited dispatch of DR resources.

NSP refers to traditional DR as load management and includes DR resources that achieve peak demand reductions during summer load in a similar fashion as a combustion turbine.

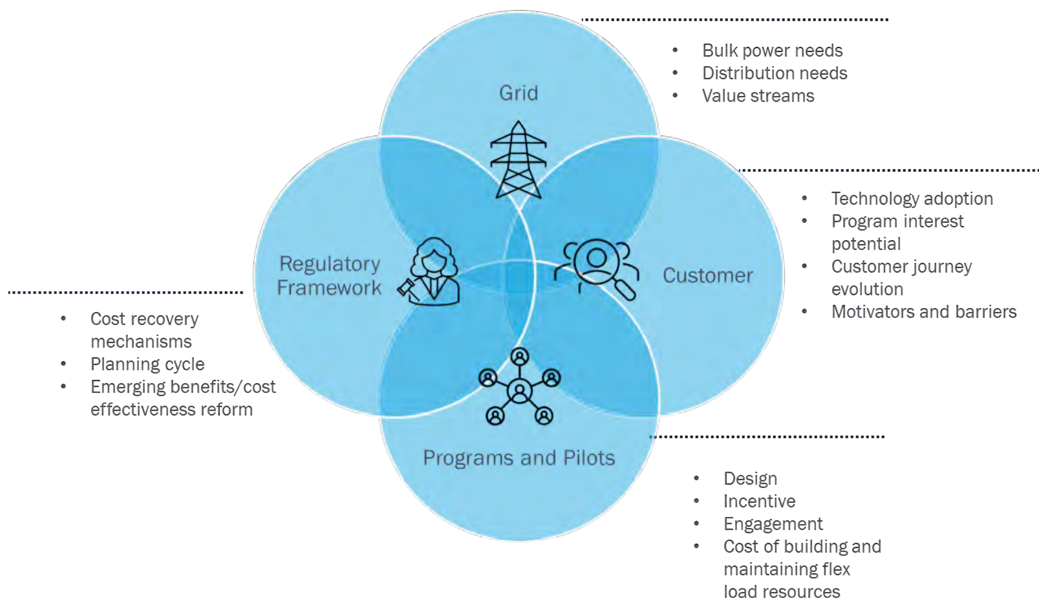
Non-traditional DR, which NSP refers to as demand management, includes options that allow customers to plan for and manage their demand differently by shifting load during different times of day impacted by new rate structures and new resources.

These anticipated changes in the market present an opportunity to revisit emerging challenges, opportunities, and value streams. NSP has made initial steps toward a meaningful transition to Load Flexibility by bifurcating traditional and non-

[8] Based on the 2019 IRP filings, while DSM programs were approved through CIP, prior decisions suggested that enabling technologies largely fell outside of the parameters for cost recovery through CIP (as did incentives for thermal storage capabilities associated with grid-enabled water heaters). Xcel Energy also experienced challenges with providing incentives for customers to purchase Level 2 smart chargers offering time-controlled charging.

traditional DR, as well as traditional and non-traditional value streams. NSP has also begun the process of assessing the potential, value stacking, and alignment of value streams with load and demand management needs. The market trends described above support the growing need for DR solutions that deliver benefits beyond curbing the need for capacity generation. NSP commissioned a 2019 potential study that identified a series of both common and emerging benefits from DR. These benefits included more traditional benefits, such as avoided generation capacity costs, reduced peak energy costs, and system-wide deferral of transmission and distribution upgrades, as well as additional benefits, such as geotargeted distribution capacity investment deferral, ancillary services, and load building/valley filling services. The potential study identified differential needs and opportunities for DR depending on the scenario and DR use cases—setting the foundation for pursuing further transformation of the DR paradigm. However, significant effort remains to identify, design, and implement DR solutions that prove the additional benefits under emerging generation, DER adoption, and technological advancement conditions. Furthermore, incorporating customer preferences and differential incentive mechanisms aligned with load management opportunities to ensure continuous customer engagement and participation will be important to explore and consider.

Preparing for Transformational Change



In these evolving conditions, the path forward requires a phased and thoughtful approach to assess, quantify, and deploy flexible load resources. Building out and maintaining these resources, whether managed charging, direct load control, or commercial DR offerings, can incur costs, both initially and in perpetuity, as long as the programs remain active. However, thoughtfully designed programs that carefully consider four intersecting spheres (depicted to the right) can bring immense value to both the utility and the customer. Importantly, these spheres overlap, providing points of integration as well as tension when formulating NSP's future engagement with load flexibility. For example, integrating a regulatory framework focused on cost causation with customer preferences associated with DER adoption may highlight rifts in traditional valuation molds. As a result, the intersections of these spheres are areas in which stakeholder engagement and discussion become increasingly germane to successful outcomes.

A thoughtful transition supported by careful planning to ensure sufficient capacity is available with the right characteristics—flexibility and fast response—to meet reliability needs at both bulk power and distribution levels is no small feat. Accordingly, such a transition cannot and should not happen overnight. The development of these flexible load resources should first rely upon well-established programs and offerings (and associated value streams) in support of the development of emergent pilots and initiatives to bridge the gap from short-term conditions to longer-term needs. A two-phased approach can help adequately prepare for the transition.

- Phase I: Next three to five years: *Plan and assess*. Reflects a period of initial transition, planning, assessment, and positioning DR toward a transformational shift to Load Flexibility, requiring iterative approaches rather than deterministic outcomes. This phase will offer careful consideration of the customer journey, value streams, and relevant program designs.

- Phase II: Next five to ten years: *Transition*. Build out a flexible load resource portfolio to satisfy likely load management challenges at the distribution level, as well as at the bulk power level. Ensure that the portfolio is sufficiently adaptable to demand forecasts.

To that end, Phase I should focus on preparing to transition NSP's DR portfolio across these four spheres: grid, customer, programs and pilots, and regulatory framework.

The Grid

Anticipated Evolution

- Seasonally varying generation system needs, constraints, and value streams
- Emerging distribution system needs, constraints, and value streams
- Emerging need to balance intermittent renewable sources of generation with evolving demand for electricity

Evolving grid needs will likely:

- Shift emphasis away from DR as simply a resource needed to satisfy RA and RM planning requirements, and instead towards active, high frequency load management.
- Unlock new value streams for flexible load solutions, such as deferred/avoided distribution system upgrades and seasonally variable value, given MISO's transition to the seasonal construct.
- Open pathways for new programs and pilots to tap into the emerging value streams, both temporally and locationally. For example, the adoption of AMI infrastructure and the emergence of new enabling technologies, DERs, and aggregation mechanisms will likely create avenues for rate-based programs and EV managed charging programs that focus on load shifting and flattening. In other cases, DERs like renewables plus storage, as well as vehicle-to-grid programs, will be capable of absorbing excess energy during times of low demand and dispatching it during times of constraint.
- Increase complexity of program interactions, as well as uncertainty around the best ways to build portfolios and stack programs to achieve the greatest grid benefits. As a result, adaptability, optionality, and flexibility will be key.

Considerations

Identify how existing DR and novel Load Flexibility offerings can best fit into the seasonal MISO construct.

Identify the extent of distribution constraints and needed upgrades to assess the best pathway for Load Flexibility to deliver locational relief. Forecasting load at the distribution level will support thoughtful planning and deployment of Load Flexibility solutions. Exploring customer composition at the distribution level (e.g., mostly commercial, mostly industrial, multifamily, etc.) will support tailoring flexible load solutions to maximize impact.

Identify interventions that support balancing intermittent renewable resources and DER adoption. For example, time-varying rates and EV managed charging solutions can permanently flatten the ramp and improve load factor. Storage solutions can support grid services. Xcel Energy is already testing storage as a load management opportunity through the Thermal Energy Storage Pilot approved under the Load Flexibility Plan in Docket No. E002/M-21-101.

Quantify unlocked value streams given evolving grid needs to guide portfolio design and program prioritization.

Customer

Anticipated Evolution

- Growing penetration of enabling technologies and end-user automation solutions
- Growing presence of DERs, such as EVs and battery storage
- Customers as "prosumers" able to consume and provide grid power

Emerging grid needs described above combined with customer evolution will likely:

- Require greater customer education around continuous load management, which differs from existing participant experiences with event-based load curtailment. The educational efforts will potentially include the concept of "reverse DR" to support excess generation during certain times of the day—a counterintuitive concept to customers.
- Require differing levels of customer engagement, depending on the load flexibility approach, DER type, and/or presence of enabling technologies. Engagement can range from permanent habitual change to event-based temporary actions to changing energy-using patterns. The enabling technology will impact the level of effort and engagement for customers.
- Require re-consideration or redesign of customer incentives and rewards, given the shift to a more continuous load management framework (Faruqi et al. 2014).

- Increase the complexity of considerations and choices related to customer engagement with Load Flexibility solutions. A greater variety of Load Flexibility options—including locationally focused programs to support distribution grid needs—may require consideration of customer engagement in multiple programs (e.g., time-varying rates stacked with event-based load curtailment programs), as well as customer evolution across the portfolio given developing customer comfort with Load Flexibility concepts, adoption of DERs, and enabling technologies.

Considerations

Understand customer technology adoption trends, willingness to adopt, drivers, and preparedness to adopt load flexibility solutions. This research will allow NSP to select and phase program development and launch in alignment with market and customer adoption trends. NSP has already commissioned foundational research, including research conducted in 2014 to assess customer adoption rates and incentive levels (Faruqi et al. 2014).

Assess customer adoption potential to identify pathways for transitioning or integrating flexible load programs into the existing DR portfolio or transitioning customers from existing programs into new ones.

Review case studies across the country to assess customer preparedness to adopt Load Flexibility programs. Such a review will allow NSP to benchmark successes and identify barriers.

Understand customer knowledge, needs, and values to support incentive design allowing NSP to strategically build customer evolution pathways.

Programs and Pilots

Anticipated Evolution

- Growth of non-traditional pilots and programs to support evolving customer needs and grid services
- Shift to programs focused on continuous load management
- Increased opportunities for automation given growth of enabling technologies and DERs

Emerging grid and customer needs described above, combined with the anticipated evolution of programs and pilots, will likely:

- Require a shift in program design, customer enrollment and participation models (e.g., dual participation), and incentive levels to support continuous load management. For example, future portfolios must consider whether customers can participate in multiple programs or limit engagement to a single program and the implications for value streams.
- Require additional and refreshed program marketing and customer education.

- Require revisiting value streams and cost-effectiveness frameworks, as well as quantifying value streams associated with pilots, to better capture the full stack of program benefits, likely beyond grid services.
- Require assessing the ability of existing systems to support new program designs. Lessons learned from time-varying rate deployment stress the importance of integrating and building out required internal systems to deploy these programs for a seamless and efficient customer experience (e.g., billing, metering). This build-out is critical in advance of any opt-out (default enrollment) program design. In addition, these activities will also support continuous load management program designs at the grid edge, such as managed charging telematics metering, among others, to ensure that customer and technology communications and protocols are executed effectively as the number of events or interventions increase in frequency (e.g., summer and winter, seasonal, continuous).
- Require alignment of future processes to ensure reliability, efficient use of resources, maximization of customer benefits, and successful implementation of public policy.

Since 2019, NSP has augmented its DR portfolio to address future grid, customer, and regulatory needs. More specifically, because traditional DR programs may be approaching enrollment saturation (Hledik et al. 2019), NSP has developed non-traditional DR pilots to lay the groundwork for the load flexibility transition. These pilots include the EV Optimization pilot, Peak Flex pilot, Commercial Thermal Storage pilot, Residential Time of Use pilot, General Time of Use pilot, Critical Peak Pricing pilot, and Peak Day Partners. NSP's non-traditional DR pilots are currently offered to residential, commercial, and industrial customers to encourage load shift, shed, and shaping—which support designing programs with peak period flexibility that can respond to changing peaks due to renewables adoption, local peaks, distributional constraints, or other triggers. NSP has begun offering a range of time-varying rates (TOU, CPP), building upon the deployment of AMI infrastructure to develop a robust offering of interventions with lower customer enrollment.

Considerations

Design and develop pilots that offer customer and grid value for the future grid, including flexible peak periods to support continuous load management at a portfolio level, as well as targeted and locational programs to unlock avoided distribution cost benefits.

Implement evaluable pilots that support decisions for scale (e.g., develop program theory and logic models, demonstrate emergent technologies, determine customer journey and value, identify and document grid benefits).

Ensure that communication protocols and systems effectively build a foundation for large scale deployment of time varying rates.

Conduct customer research to determine whether customer incentives align with grid value; identify opportunities to integrate and aggregate DER values.

Identify and quantify new unlocked value streams.

Regulatory Framework

Anticipated Evolution

- Increasing regulatory pressure to expand DR MW potential
- Evolving cost-effectiveness paradigms
- Expansion of realizable DR value streams

Evolving regulatory frameworks will likely:

- Demand that NSP further expand DR MW potential in the face of climate goal mandates and evolving grid needs and capabilities.
- Allow for revised regulatory acceptance of non-traditional DR, including Load Flexibility offerings that were previously deemed not cost-effective under prior regulatory paradigms. These regulatory changes can open the floodgates for previously untapped Load Flexibility opportunities in NSP's service territory. Regulatory headwinds have already begun to shift, as marked by the recent change to Minnesota Statutes regarding rules concerning cost-effective load management programs. Going forward, NSP will be able to test and develop even more innovative non-traditional DR pilots and programs.
- Expand DR value streams, such as distributional value streams, and increase non-dispatchable renewable energy integration.

Considerations

Collaboratively work with stakeholders to revise, refine, modernize, and adapt regulatory frameworks as needed to ensure (1) the ability to flexibly adapt programs and pilots to rapidly changing technological landscape and continuously evolving needs of the customers and the grid; (2) collaborative assessment of emerging value streams from DERs and incorporating them into the cost recovery, cost-effectiveness, and other frameworks to reflect the full stack of benefits available from DERs.

Explore effective filing processes such as the load flexibility petition and/or R&D in ECO filings.

Identify and gain regulatory approval for other novel methods to incentivize customers to participate in Load Flexibility programs.

APPENDIX A. DETAILED CASE STUDIES

Public Service Company of Colorado Renewable Battery Connect Program

Load Control Strategy

Starting as a pilot offering in 2021, the Public Service Company of Colorado's (PSCo) Renewable Battery Connect Program charges and discharges residential solar-powered batteries during low and high-demand periods, respectively. Although events can be called at any time during the year, discharge events typically take place on the hottest days of the year, during the afternoon and evening. The remainder of the events target non-summer months to evaluate non-summer performance and solar time shifting. The program is limited to 60 events per year, with most of the charging events lasting around two hours and the majority of the discharge events lasting around three hours. Customers are divided into four groups to test a Randomized Control Trial to estimate baselines and load impacts associated with the program. There is a fifth group for customers located behind constrained feeders, which can allow for geotargeted load relief. This program uses both charge and discharge load control strategies, dispatching batteries to either charge (thereby utilizing excess solar capacity) or discharge to power participating homes and send excess power back to the grid (providing demand relief to the grid).

Program Implementation

The program is implemented by PSCo, which handles recruitment, event dispatch, and incentive distribution.

Program Design: Recruitment, Enrollment, and Opt-Outs

Eligible customers are recruited via solar and battery providers, as the battery equipment must be newly installed through an interconnection application with the Company. For their participation, participants receive $500 per kW of energy storage installed (up to 50% of the equipment-only cost)[9] and a $100 annual participation incentive (for five years) for participating in control events. There is no way to opt out of a given event other than unenrolling from the program altogether.

Program Design: Eligibility

Single-family residential homes and small business customers with solar systems and a newly installed Tesla Powerwall or SolarEdge Home Hub Inverter with a SolarEdge Home Battery are eligible to participate. Further, customers must have an interconnection agreement with PSCo and maintain the connection of their Tesla Battery and/or SolarEdge inverter through a cellular or high-speed internet connection.

Program Achievements: Enrollments and DR Potential

The pilot (which ended in September 2022) had 152 participants as of the pilot's end, yielding an estimated 1.7 MW of DR potential. The scaled program currently has 65 fully enrolled participants with 90 batteries, and another 200 applications are currently going through the interconnection process. Evaluated program impacts are still forthcoming. The program has a target of 1,850 participating customers and 10 MW of DR potential by the end of 2025.

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[9] Income-qualified customers receive an increased incentive of $800 per kW of energy storage installed (up to 75% of the equipment-only cost).

Pacific Gas and Electric Peak Power Rewards Program

Load Control Strategy

Launched in 2023, Pacific Gas and Electric's (PG&E) Peak Power Rewards (PPR) Program discharges residential solar-paired batteries every day from 7:00 p.m. to 9:00 p.m. from August to October. This load control strategy dispatches batteries to power participating homes and to send excess power back to the grid.

Program Implementation

The program is implemented by Sunrun, which handles recruitment, remote battery programming and optimization, and incentive distribution.

Program Design: Recruitment, Enrollment, and Opt-Outs

All eligible customers are recruited via marketing materials sent from Sunrun notifying the customer that their home will be enrolled in PPR and they will receive incentives for their participation. Eligible customers are auto-enrolled in PPR and must manually opt out if they do not wish to participate in the program. PPR participants receive a $750 VISA gift card in exchange for their participation. PPR participants also receive a smart thermostat (unless they already received one through a different PG&E program). However, the smart thermostats are not dispatched during battery discharge events. Rather, the additional device serves as a participation incentive and offers another tool that customers can use to manage their load in the face of nightly events. The batteries are programmed to dispatch every day during the event season—there is no way to opt out of a given event other than unenrolling from the program altogether. Sunrun may clawback any unused funds on the VISA gift card if a participant subsequently unenrolls from the program.

Program Design: Eligibility

Single-family residential homes with Sunrun solar systems and LG Chem, SolarEdge, or Tesla Powerwall batteries are eligible to participate. Further, customers must have an interconnection agreement with PG&E and may not be enrolled in other demand response programs.

Program Achievements: Enrollments and DR Potential

Initially, the program was limited to 7,500 participants. Following low opt-out rates and rising interest in solar+storage, the program cap was met and subsequently expanded to 8,500 customers, yielding an estimated 34 MW of DR potential.[10] Evaluated program impacts are still forthcoming.

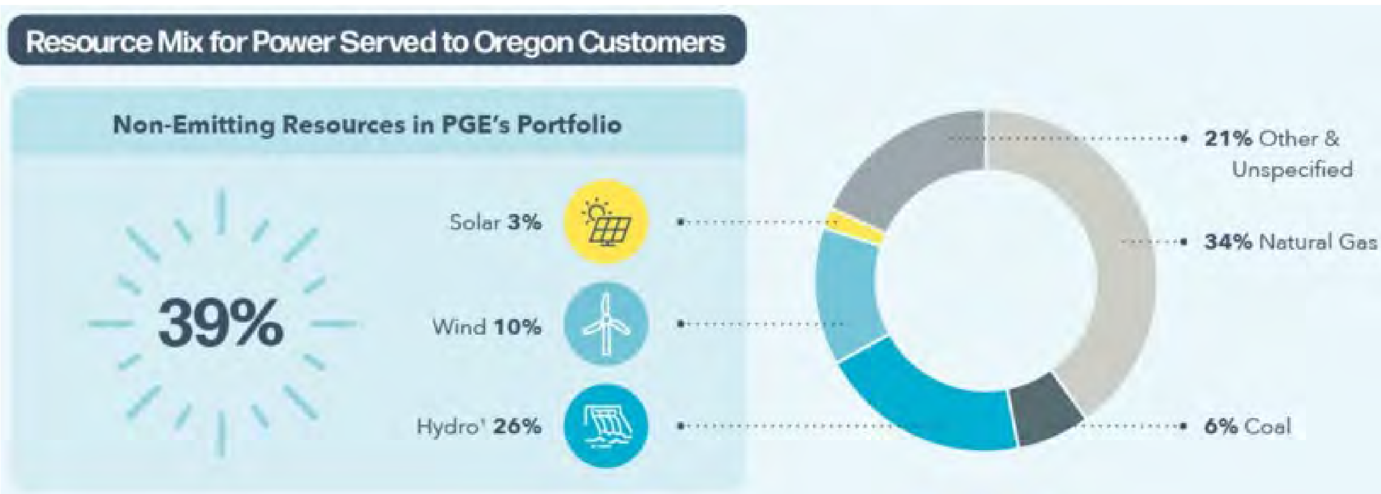
[10] https://www.pgecurrents.com/articles/3795-sunrun-pg-e-expand-collaboration-energy-efficiency-summer-reliability-program

Portland General Electric Multifamily Water Heater Pilot

Utility Background

Portland General Electric (PGE) is Oregon's largest electric utility, serving the state's two largest cities (Portland and Salem) and the surrounding communities. PGE has over 900,000 retail customers within a service area of 1.9 million residents, which encompasses approximately half of Oregon's population and about 75% of Oregon's commercial and industrial activity.[11] PGE is vertically integrated, providing generation, transmission, and distribution. Figure 1 illustrates PGE's Generation Portfolio. PGE owns and operates its own hydro generation facilities; however, it also purchases some of its hydropower from the Bonneville Power Administration (BPA).

Figure 1. PGE Generation Portfolio



Source: PGE Clean Energy Plan and Integrated Resource Plan 2023

While PGE is an electric-only utility, natural gas is used abundantly in their territory and fuels much of the space and water heating in their service area. Despite the comparatively mild weather, air conditioning load has grown considerably over the last decade or so. This insurgence of mechanical air conditioning, combined with moderate levels of electric space and water heat in single-family homes[12] and high penetration of these electric end uses in multifamily buildings,[13] helps explain why PGE is a dual-peaking utility. As seen in Figure 2, PGE's winter peak is currently greater than its summer peak, but the two are expected to converge in the next decade or so (likely due to anticipated air conditioning load growth and potentially hotter summers). PGE's summer peak occurs in the late afternoon/early evening. Meanwhile, their winter season experiences two daily peaks: one in the morning and another in the late afternoon/early evening.

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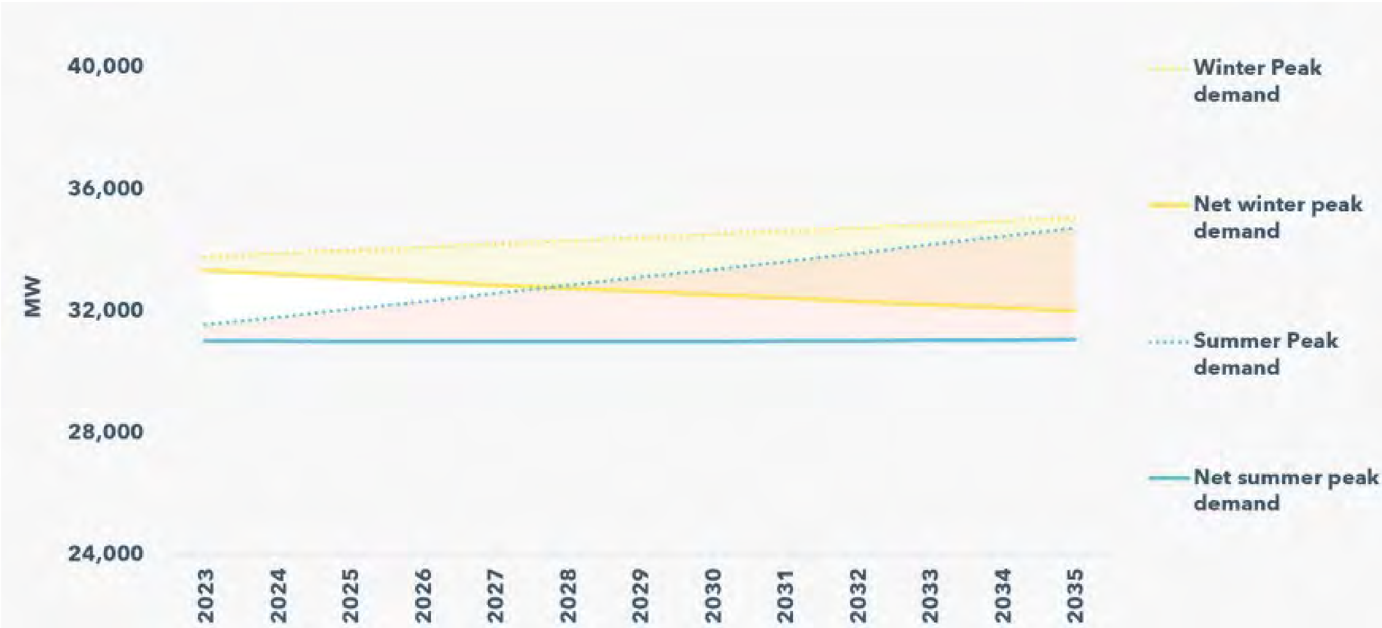
11 https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLX0Bgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf
12 https://neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf
13 https://neea.org/img/documents/Residential-Building-Stock-Assessment-II-Multifamily-Homes-Report-2016-2017.pdf

Figure 2. PGE Peak Load Forecasts



Source: PGE Clean Energy Plan and Integrated Resource Plan 2023

Program History

PGE participated in a BPA-managed NW Power Conservation Council water heater Load Flexibility study and has since grown its own multifamily program into over 10,000 units. The BPA pilot used the EcoPort predecessor (CTA-2045 + FM signals) to communicate with and dispatch single-family water heaters. Although successful, there were technological challenges with the communications technology. Specifically, they were clunkier and not standardized, and customers would often uninstall them. A subsequent PGE single-family pilot struggled to meet enrollment needs, as enrolling owner-occupants proved challenging. This single-family pilot tested various communications pathways: cellular LTE and utility mesh network. Meanwhile, PGE also set up a multifamily pilot, which has proved to be very successful, as working with multifamily property managers (who receive an annual cash incentive per enrolled water heater) has proved to be a successful enrollment strategy. The information in this section represents PGE's current Multifamily Water Heater Pilot.

Load Control Strategy

Launched in 2018, PGE's Multifamily Water Heater Pilot uses wi-fi and cellular switches to dispatch 38–50-gallon electric resistance water heaters in multifamily properties every non-holiday weekday.[14] Dispatch times depend on grid needs and are typically 5:00 p.m. to 8:00 p.m. in the summer, while winter months see both morning (typically 6:00 a.m. to 9:00 a.m.) and evening (typically 5:00 p.m. to 8:00 p.m.) dispatches. PGE will extend events by an hour or two when other [non-daily] DR programs are being called to minimize snapback [event end] peaks. Individual events are capped at eight hours, although PGE has yet to exceed five. This load control strategy effectively converts water heaters into thermal batteries, heating water when demand is low and providing load relief during daily peaks without sacrificing tenant comfort.

[14] PGE stopped installing wi-fi units in October 2019, as cellular switches are significantly more likely to maintain the connectivity needed for dispatch.

Program Implementation

The program is implemented by PGE, which handles recruitment, enrollment, and incentive distribution. PGE uses local trade allies to install the switches.

Program Design: Recruitment, Enrollment, and Opt-Outs

PGE recruits multifamily property management companies to opt their units into the pilot. In exchange, property management companies receive an annual cash incentive of $20 per connected water heater. The pilot also provides tenant incentives in the form of coupons to local businesses.[15] On installation day, a tenant may refuse entry to the contractor, or the contractor may not be able to enter the unit if there are unaccompanied minors or loose dogs, which in turn prevents the switch from being installed. These circumstances are fairly rare, as shown by the pilot installation rate of 89%. Upon installation, tenants receive educational materials that explain the pilot and voluntary opt-out instructions. The pilot has yielded a tenant opt-out rate of <1% and tenant surveys have demonstrated that most did not realize they were in a program in the first place nor that they had experienced any hot water shortages. Of the pilot's 1,000,000+ touches, <1% have resulted in cold water calls to PGE, and of those, <1% end up being at the fault of the program. If the tenant chooses to opt out, the installed device will stay in place but will no longer be in operation until a new tenant moves in.

Program Design: Eligibility

Multifamily properties with at least 50 individually metered units that have 38–50-gallon electric resistance water heaters are eligible to participate. PGE will not install retrofit control switches on units that are >20 years old. As new smart water heaters with CTA-2045 capabilities begin to penetrate the market, PGE will install EcoPort communications devices on these modern units.

Program Achievements: Enrollments and DR Potential

As of the end of 2022, PGE installed over 13,000 switches, averaging ~2,600 new installations per year. These switches are distributed across 111 properties and 32 property management companies (including 12 of the 25 largest in PGE territory). Evaluated impacts demonstrated 0.2kW per unit in summer and 0.35kW per unit in winter, resulting in an annual capacity of 2.4MW in the summer and 4.5MW in the winter.

[15] Tenant incentives are currently being reevaluated due to the closure of the local coupon company partner.

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APPENDIX K – ENVIRONMENTAL REGULATIONS REVIEW

I. INTRODUCTION

This appendix provides high level discussions on environmental regulations impacting planning and operation of the Company's assets.

II. GREENHOUSE GAS AND CLIMATE LEGISLATION AND REGULATION

A. New Source Performance Standards 111(b) and (d)

On May 11, 2023 the U.S. Environmental Protection Agency (EPA) released a four-part proposal under their Clean Air Act authorities to regulate CO2 emissions from the power sector. The proposal included:

1) Repeal of the Affordable Clean Energy rule;
2) Regulations for new natural gas generating units pursuant to Clean Air Act section 111(b), hereafter referred to as 111(b);
3) Regulations for existing natural gas generation pursuant to Clean Air Act section 111(d), hereafter referred to as 111(d); and
4) Regulations for existing coal generation pursuant to section 111(d).

Xcel Energy filed comments on the proposed rule on August 8, 2023. We anticipate a final rule will be released in spring of 2024. Potential impacts of these new regulations have been incorporated into modeling efforts as a sensitivity recognizing that impacts on our existing natural gas fired units, discussed below, located at our Black Dog, and High Bridge facilities could be significant if the regulation is finalized as proposed. We provided an initial assessment of the potential impacts to our system to the Department in information request number 128 filed in docket number E002/RP-19-368 on July 28, 2023 with a supplement filed August 16, 2023.

Since the rule is in a proposed state and not yet finalized, it is uncertain how the rule will ultimately impact operation of our facilities. If the rule is finalized as currently proposed, there will be no impact from the repeal of the Affordable Clean Energy rule for any utility, as the D.C. Circuit Court vacated the rule on January 19, 2021, and remanded the rule to the EPA for further proceedings. Nor will we be adversely impacted by the regulations setting standards for existing coal generation under section 111(d) if adopted as proposed, as all NSP coal units are scheduled to cease operation by December 31, 2030. Sherburne County Generating Plant (Sherco) Unit 3 will be our only coal unit operating in the Upper Midwest in 2030, and will technically be impacted in 2030 with a unit-specific limit based on a five-year lookback period. As long as the unit does not increase emissions of carbon dioxide (CO2) in 2030, it should be able to comply with the limit.

The Company may be impacted by the proposed regulations for new natural gas generating units and the proposed regulations for existing natural gas generation units.

The proposed rule for new gas units requires implementation of the best system of emission reduction (BSER) and includes sub-categories for low, intermediate, and base-load units. For low load units (<20 percent capacity factor), the BSER is the use of fuels (natural gas, Nos. 1 & 2 fuel oil) for meeting emission standards. For intermediate load units (capacity factor that ranges between 20 percent and a source-specific upper bound), the standards of performance for Phase 1 require highly efficient operations and for Phase 2 require meeting an emission rate equivalent to blending 30 percent hydrogen beginning in 2032. For base load units (units operating above the upper-bound threshold for intermediate load units), the standards of performance are set based on whether a unit chooses the carbon capture and sequestration (CCS) pathway or the hydrogen pathway. For CCS, the unit must meet standards based on 90 percent capture of CO2 by 2035. For hydrogen, the unit must meet a Phase 2 standard based on co-firing 30 percent hydrogen by 2032 and a Phase 3 standard based on co-firing 96 percent hydrogen by 2038. EPA has designed these two pathways – hydrogen blending or CCS – so that they achieve the same level of CO2 emission reductions by 2038.

The standard for existing gas units impacts units with a nameplate capacity greater than 300 MW and capacity factors greater than 50 percent. The proposed emission guidelines also offer the two-pathway approach of hydrogen blending or CCS on the same timeline as the new baseload unit standard described above. States are given primary responsibility in establishing compliance pathways for existing units through state plans, which are required to be submitted to EPA for approval within two years after the final rule is issued. In developing state plans, the states can consider the remaining useful life and other factors of the existing source in setting standards of performance that reflect the EPA emission guidelines. Therefore, impacts to specific plants will depend on state plans and could diverge from the emission guidelines. Given this state plan process, it is difficult to predict outcomes at this time. Depending on capacity factors, Black Dog Unit 5/2, Riverside Units 9 and 10, and High Bridge Units 7 and 8 may be affected by this standard. For modeling purposes, as a sensitivity, we have presumed that Riverside Units 9 and 10 are not affected by the rule but that Black Dog Unit 5/2, and High Bridge Units 7 and 8 are affected. The affected units have been modeled in the sensitivity with a presumed 50 percent capacity factor limitation so that the units are not required to make any modifications based on the proposed rule.

For existing coal fired steam generating units, the rule provides three sub-categories based on the planned retirement date of the generating unit. Xcel Energy expects all of our coal units to fall into the "Imminent-term" retirement category which requires a unit to permanently cease operation before January 1, 2032. This timeline is consistent with the retirement dates in our filed resource plans.

B. MN Legislation 100 by 2040

In 2023, the Minnesota Legislature passed a new law requiring utilities, including Xcel Energy, to generate or procure carbon-free energy equivalent to 100 percent of its Minnesota retail sales by 2040. The law, Minn. Stat. § 216B.1691, also requires Xcel Energy to achieve interim carbon-free standards of 80 percent by 2030 and 90 percent by 2035, and a renewable energy standard of 55 percent by 2035. The Company is positioned to achieve compliance with the new legislation under our 2024 Preferred Plan as presented here. A table demonstrating compliance with the legislation is provided in Table K-1 based on the Preferred Plan modeling outcomes filed in this IRP.

A detailed discussion of this legislation can be found in Chapter 2: Planning Landscape and in Appendix N: Standard Obligations.

Table K-1: 2024 Preferred Plan Carbon-Free Energy

	2030	2035	2040
Carbon-Free Generation (GWh)	46,515	52,681	60,162
MN Allocated CF Generation (GWh)	35,644	40,668	46,666
MN Elec Retail Sales (GWh)	35,725	39,668	44,624
Percentage Carbon Free Generation	80+%	90+%	100%
Carbon Free Standard Requirement	80%	90%	100%

The Commission has opened an Investigation docket[1] into Minnesota's Carbon Free Standard as codified in Minn. Stat. § 216B.1691, Subd. 2g. Parties, and the Commission will weigh in on a number of topics in that docket over the next couple of years. Some nuances and open questions remain to be considered in that docket, which could influence future compliance depending on implementation requirements.

[1] Docket No. E999/CI-23-151.

III. COST OF CARBON AND EXTERNALITIES

A. Regulatory Cost of Carbon

The Regulatory Cost of Carbon values established by the Commission are applied in our modeling process as a cost adder and impact the selection of resources and how they are dispatched. The CO2 regulatory cost range is applied in resource planning models as a cost faced by any fossil generation resource, affecting both the dispatch of resources and expansion plan choices. The CO2 regulatory cost range is intended as a proxy for regulatory costs that utilities and their customers may face, beginning in the year they are expected to incur these costs, so that resource planning and acquisition decisions can consider the impacts of those costs on long-term capital investments. This cost range is meant to capture regulatory costs only. Societal damages from climate change are separately addressed using the CO2 environmental cost range established under Minn. Stat. § 216B.2422, Subd. 3 and per the December 19, 2023, Commission Order in Docket Nos. E999/CI-07-1199, E999/DI-22-236, and E-999/CI-14-643 Addressing Environmental and Regulatory Costs (Environmental and Regulatory Costs Order) discussed below under MN Externality Values. This is discussed further in Appendix F: EnCompass Modeling Assumptions and Inputs.

On August 1, 2007, the Next Generation Energy Act became effective, which provided direction to the Commission to estimate how the future regulation of CO2 emissions would affect the cost of generating electricity, and directed the Commission to establish a range of these cost estimates, revise them annually, and to use the estimates "in all electricity generation resource acquisition proceedings." Table K-2 below provides a summary of historical and current cost estimates listing only the years where the Commission changed the established cost range per ton of CO2. These Cost of Carbon estimates have not been included in the North Dakota scenarios.

Table K-2: Summary of Historical and Current CO2 Cost Estimates

Year Established Range was Adjusted	Cost Range (per ton of CO2)
2007	$4.00 to $30.00
2011	$4.00 to $34.00
2012	$9.00 to $34.00
2018	$5.00 to $25
2023 (to be applied beginning in 2028)	$5.00 to $75.00

In 2018, the Commission lowered both the lower and upper bound of the regulatory cost range because the Minnesota Pollution Control Agency (MPCA) and the Minnesota Department of Commerce noted in their comments that the price of a permit to emit a ton of CO2 had declined over time, at least as measured in trading exchanges, such as the Regional Greenhouse Gas Initiative (RGGI). In 2020, the Commission did not make any adjustments to the range. The regulatory cost range was modified in 2023 with the new values being applied beginning in 2028.

The purpose of establishing a regulatory cost of carbon from the generation of electricity was to be able to use those values in various modeling scenarios as an estimate of the per ton cost impacts of potential future regulations limiting CO2 emissions. In the 2023 Minnesota State Legislative session, a bill was passed mandating that all Minnesota utilities generate or procure set amounts of electricity from carbon-free energy technologies meeting a prescribed schedule, culminating with 100 percent carbon free generation and procurement in 2040. Additionally, as discussed in the last section, the EPA has proposed standards regulating CO2 emissions from the power sector. It is the position of the Company, and other Minnesota utilities and interest groups, that this legislation obviates the need for the regulatory cost of carbon to continue, as regulations now require the Company and other utilities to comply with CO2 emission constraints which eliminates the need to model potential CO2 emission reduction requirements as a theoretical future cost of regulatory compliance. Thus, the Company – and other parties – still believe $0 should be an acceptable lower bound of the range but have conducted modeling in compliance with Commission Orders.

B. MN Externality Values

The Minnesota Public Utilities Commission ordered the use of externality values for CO2 and criteria pollutants in its order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. For the North Dakota scenarios, these values have not been included.

Values were established by the Commission for emissions of CO2 and criteria pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), particulate matter less than 2.5 microns (PM2.5), carbon monoxide (CO), and lead (Pb). CO2 values were established considering Federal Interagency Working Group (IWG) Technical Support Document[2] guidance and included costs on a per short ton basis, with a low, mid and high range provided. Values

[2] Available at: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

for the criteria pollutants were also provided on a per short ton basis for four locations: Urban, Metro Fringe, Rural and within 200 miles of the MN border. A range of low, midpoint and high values were established.

In the new 100 by 2040 legislation, Minn. Stat. § 216B.2422, Subd. 3, the Commission was directed to provisionally adopt and apply the cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's November 2023 Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advance[3] (EPA SC-GHG) including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The Commission provisionally adopted and applied the EPA SC-GHG, for purposes of measuring environmental and socioeconomic costs under Minnesota Statutes § 216B.2422, subdivision 3., as reflected in the Environmental and Regulatory Costs Order.[4] The PVSC Base Case Greenhouse Gas (GHG) values, inclusive of carbon dioxide, methane and nitrous oxide, are based on the mid EPA SC-GHG values, with the high and low EPA SC-GHG values as sensitivities per the Environmental and Regulatory Costs Order.

While the regulatory cost of carbon is taken into consideration in modeling in the PVSC scenarios, thus affecting dispatch order, the EPA SC-GHG costs are applied post processing and do not impact dispatch order. The PVRR sensitivity does not include environmental cost adders including regulatory and externality values. All prices are converted from metric ton to short ton and to nominal dollars using two percent escalation factor. The application of these values is further discussed in Appendix F: EnCompass Modeling Assumptions and Inputs.

IV. MN ENERGY OMNIBUS: CUMULATIVE IMPACTS

In 2023, the Minnesota Legislature passed a new law, Minn. Stat. § 116.065, requiring Cumulative Impacts Analysis for Permit Decisions in Environmental Justice Areas (EJ Areas). This law will require applicants seeking air permit actions with potential to substantially impact residents of an EJ Area to conduct cumulative impacts analysis for facilities located in Anoka, Carver, Dakota, Hennepin, Ramsey, Scott, or Washington counties, Duluth and Rochester. The new state definition of Environmental Justice Area

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[3] Available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf
[4] ORDER ADDRESSING ENVIRONMENTAL AND REGULATORY COSTS. December 19, 2023. Docket No. E-999/CI-07-1199. Docket No. E-999/DI-22-236. Docket No. E-999/CI-14-643.

was adopted consistent with the 100 by 2040 law, in addition to a new definition of Cumulative Impacts, "the impacts of aggregated levels of past and current air, water, and land pollution in a defined geographic area to which current residents are exposed." If the Cumulative Impacts analysis finds significant adverse impacts would result from the permit action, then a community benefits agreement must be established, or permits may be denied. Additionally, community engagement in EJ Areas will be required during the process.

The full extent of these new requirements is not fully known at this time. The MPCA was given broad discretion and was directed to set new rules governing cumulative impacts analysis and community benefit agreements, which will provide a framework, guidance, and clarify the requirements of this new law. MPCA has opened a general request for comments, related information, and ideas from those affected by the rulemaking which ended October 6, 2023[5] and is early in a three-year process to gather information and draft proposed rules for public comment by May 24, 2026.[6] The Company submitted a supportive letter in response to the initial request for comments providing information on related experience in this area and will likely participate further in the rulemaking process. MPCA has updated its EJ Area Map[7] based on the new state definition, although we note a statistical adjustment is applied which is not consistent with the state definition. The Company operates several existing generation facilities in the greater metro area which will likely be subject to these new requirements when implemented. Dependent upon final MPCA interpretation and rulemaking, the impacts could be significant to permit issuance for existing and new generating facilities.

V. CONVENTIONAL POLLUTANTS & HAZARDOUS AIR POLLUTANTS

This section discusses requirements applicable to air emissions of pollutants regulated under the Clean Air Act (CAA). The four primary regulatory categories addressed are: 1) National Ambient Air Quality Standards (NAAQS), 2) Interstate transport of air pollution, 3) Visibility Impairment in National Parks and Wilderness Areas, and 4) Hazardous Air Pollutants. Each is addressed in the following sections.

[5] MPCA Request for Comments on Cumulative Impacts Rule, available at: https://minnesotaoah.granicusideas.com/discussions/39398-minnesota-pollution-control-agency-request-for-comments-on-cumulative-impacts-rule.

[6] MPCA Cumulative impacts rulemaking, available at: https://www.pca.state.mn.us/get-engaged/cumulative-impacts.

[7] MPCA EJ Area Map, available at: https://mpca.maps.arcgis.com/apps/MapSeries/index.html?appid=f5bf57c8dac24404b7f8ef1717f57d00#map.

A. National Ambient Air Quality Standards

The CAA requires the United States Environmental Protection Agency (EPA) to set NAAQS for air pollutants that are common in outdoor air, considered harmful to public health and the environment, and are emitted from numerous and diverse sources. NAAQS include both (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children and the elderly and (2) secondary standards to protect public welfare, including protection against damages to animals, crops and buildings. The EPA has established NAAQS for six pollutants: particulate matter (PM), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), ozone (O_3), carbon monoxide (CO), and lead (Pb). The EPA is required to review the NAAQS every five years and revise them as appropriate to protect public health and welfare.

The CAA requires EPA to conduct periodic review of the science upon which the standards are based and revise the standards if necessary. The process begins with assessments of the updated relevant science, the latest risk/exposure information, and a policy assessment. EPA compiles this information and revises or develops new NAAQS through a public rulemaking process, if warranted.

Once EPA adopts or revises a NAAQS, states have two years to monitor the air, analyze the data and submit to EPA their recommended classification of the state into one of three categories: 1) Attainment areas (areas having monitored ambient air quality concentrations below the NAAQS), 2) Nonattainment areas (areas having monitored ambient air quality concentrations above the NAAQS), or 3) Unclassifiable areas. The EPA reviews the state's submittal and determines final area designations. When EPA designates an area in a state as Nonattainment, the state is given up to three years to develop a new State Implementation Plan (SIP) which identifies actions required to bring the area into Attainment. A SIP must include emission reduction requirements to demonstrate that air quality will attain the NAAQS within a given time period as required by the CAA.

Presently there is only one Nonattainment area in the state of Minnesota, a small nonattainment area for Lead emissions for an area surrounding Gopher Resource Corporation, a lead smelter and battery recycling company in Eagan in Dakota County. As a result, no emission reduction requirements are being imposed on Xcel Energy's Upper Midwest power plants through a state SIP due to NAAQS.

EPA has proposed changes to the PM NAAQS, lowering the level of the annual particulate matter less than or equal to 2.5 microns in diameter ($PM_{2.5}$). Sources contributing to $PM_{2.5}$ emissions include dust (agricultural, construction and road) and fire (wildfires, prescribed fires and agricultural fires). Other lesser contributing anthropogenic sources of $PM_{2.5}$ emissions nationally include stationary fuel combustion and agricultural sources. In urban areas the largest $PM_{2.5}$-emitting sectors are mobile sources and fuel combustion. Once the proposed rule is finalized the MPCA will need to monitor the air, analyze the data and submit a proposed designation to EPA. EPA will have to review the proposal and issue a designation, then MPCA will develop a SIP to ensure compliance with the new NAAQS. This process will take many years and all Xcel Energy Upper Midwest coal units are committed to retire by 12/31/2030, making it unlikely that any additional controls will be required for NAAQS Compliance for any Xcel Energy units located in Minnesota.

The EPA recently announced (August 21, 2023) that the 2021 Ozone NAAQS reconsideration will be revisited during the 2024 Ozone NAAQS review process. We do not anticipate this process will be concluded prior to 2024.

B. Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[8] The EPA has developed programs to reduce interstate transport of pollutants emitted by Electric Generating Units (EGUs) that are precursors to ozone and fine particles focusing on emissions of oxides of nitrogen (NO_x) as a surrogate for NO_2, and is a precursor to ozone and fine particle formation, and emissions of SO_2, which is a precursor to fine particle formation. EPA also has an obligation to ensure that air emissions from upwind states do not result in NAAQS non-attainment in downwind states. This obligation is addressed with the Cross State Air Pollution Rule and is bolstered by the Good Neighbor Plan that further reduces seasonal NO_x emissions by revising and strengthening the Group 3 CSAPR ozone seasonal NO_x allowance trading program. Each of these is described in more detail in the following sections.

1. Cross-State Air Pollution Rule

EPA designed the Cross-State Air Pollution Rule (CSAPR) as a "cap-and-trade" program that reduces overall emissions of SO_2 and NO_x from EGUs. This means that total

[8] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

emissions from EGUs in a state or region are limited (the cap) and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

CSAPR imposes emission limits on EGU's in upwind states on one or both of the following: (1) summer season NO_x emissions (to address ozone), and/or (2) annual NO_x and SO_2 emissions (to address fine particles), depending on the outcome of EPA's analysis of an upwind state's contribution to Nonattainment in downwind states. In Minnesota's case, the concern is the potential impact of fine particle emissions on Nonattainment areas in downwind states, rather than ozone. Since 2015, CSAPR has applied to Minnesota sources for fine particle precursors and to Wisconsin sources for fine particle precursors and ozone precursors. NSP-Minnesota holds sufficient emission allowances to meet CSAPR requirements, while NSP-Wisconsin has complied through operational changes and the purchase of some allowances.

EPA will continue to use CSAPR as one tool to achieve attainment of NAAQS throughout the country, even as the NAAQS are revised over time.

2. *Good Neighbor Plan*

On February 13, 2023, the EPA finalized a rule disapproving 19 State Implementation Plan (SIP) submissions (including Texas) and partially approving/partially disapproving two SIP submissions (Minnesota and Wisconsin) addressing the "interstate transport" or "Good Neighbor" provision of the CAA for the 2015 Ozone NAAQS. This action led to a final "Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone NAAQS" that was published in the Federal Register on June 5, 2023, referred to as the Good Neighbor Plan. The Good Neighbor Plan included Minnesota and Wisconsin in the Group 3 ozone NO_x allowance trading program, beginning with the 2023 Ozone NO_x season (May-September 2023).

On April 14, 2023, an industry coalition, including Northern States Power-MN, filed a petition for review in the 8th Circuit Court of Appeals (8th Circuit) regarding the SIP partial disapproval in Minnesota. On May 31, 2023, the coalition filed a motion to stay the SIP disapproval and on July 5, 2023, the 8th Circuit granted a Stay of the SIP Disapproval for Minnesota. This effectively means that the Good Neighbor Plan (CSAPR Group 3 ozone NO_x program) is not in effect for Minnesota during the litigation. Depending on the litigation outcome, the Good Neighbor FIP may or may not apply in Minnesota after the resolution of the litigation.

The Good Neighbor Plan applied to Wisconsin sources from August 4-September 30, 2023 and will continue to apply in future ozone seasons. Subject sources are required to comply with the Group 3 ozone NO_x program for the entire Ozone NO_x season. NSP-Wisconsin will comply through operational changes and potentially allowance purchases. There is a possibility that the liquidity of the allowance market may tighten resulting in limited allowances being available for purchase potentially resulting in higher allowance costs in years 2030 and beyond due to dynamic budgeting and annual bank recalibrations. Regulated entities will need to monitor the markets and accommodate accordingly for compliance. Depending on the price of future allowances, dispatch order could be impacted and the need to purchase additional allowances could result in significant additional operational costs presuming that allowances are available to purchase on the open market.

These regulations have been incorporated into modeling efforts based upon estimated allowance allocations through 2029 based on information in the proposed rule. Modeling for affected units located in WI have been included in the base case scenario modeling. Modeling for units located in MN – both those owned by the Company or contracted by the Company - have been included as a sensitivity to determine the potential impacts of the rule in case it is ultimately adopted and applied in MN. Modeling efforts are further discussed in Chapter 5: Economic Modeling Framework and Appendix F.

C. Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed, and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing, and preventing future, visibility impairment from man-made air pollution in specified “Class I” areas: national parks and wilderness areas throughout the United States, including the Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (VNP) in Minnesota. The visibility programs focus on reducing emissions of PM, SO_2 and NO_x as pollutants that can result in visibility impairment from EGUs.

The EPA has taken a two-step approach to implement the visibility program. The first step, “reasonably attributable visibility impairment” (RAVI), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. In 1999, the EPA adopted the Regional Haze Rule (RHR) to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs must also include reasonable progress goals and periodic evaluation/revision cycles designed to ensure appropriate progress toward the national goal of no human-caused visibility impairment in Class I areas by 2064. These SIPs must be revised approximately every ten years to continue making reasonable progress toward reaching the 2064 national goal.

The MPCA developed, and EPA approved, Minnesota's regional haze plan for EGUs for the first ten-year planning period of the program. The MPCA's plan for Sherco Units 1 and 2 required combustion controls to reduce NO_x emissions (Over-Fire Air (OFA), combustion controls and Low- NO_x burners) and scrubber upgrades to reduce SO_2 emissions. These controls were installed and are in operation.

On December 20, 2022, the MPCA submitted a comprehensive SIP update for the second regional haze implementation period (2018-2028). The update for the second implementation period outlines significant improvements in visibility at BWCA and VNP, identifies additional emission reduction opportunities, examines the uniform rate of progress projected to 2064, and sets reasonable progress goals for 2028. The update utilizes federally enforceable conditions setting Xcel Energy unit retirement dates to satisfy emission reduction requirements:

- Sherburne County Unit 2 – by 12/31/2023 (air emission permit condition)
- Sherburne County Unit 1 – by 12/31/2026 (air emission permit condition)
- Allen S. King Unit 1 – by 12/31/2028 (Administrative Order)
- Sherburne County Unit 3 – by 12/31/2030 (Administrative Order)

The MPCA's plan update is under EPA review.

D. Hazardous Air Pollutant Emissions

1. Mercury and Air Toxics Regulation

Both state and federal regulations require reductions in Hazardous Air Pollutant (HAP) emissions, which includes emissions of mercury and air toxics, from power plants. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act (MMERA) which required reductions of mercury emissions from coal fired power plants and in 2012, the EPA adopted its rule establishing National Emission Standards for Hazardous Air Pollutants (NESHAPs) from coal- and oil-fired power plants. This rule is often referred to as the Mercury and Air Toxics Standard (MATS), and compliance was required in 2015. Mercury controls were installed and are operational on all three Sherco units and at King based on these regulations.[9]

MATS also set emission limits for acid gases and non-mercury metals. PM is a surrogate for non-mercury metal emissions and SO_2 is a surrogate for acid gas emissions. The Sherco and King plants meet these standards using control technologies and best operational practices.

In May 2020, EPA finalized the risk and technology review (RTR) for the MATS coal- and oil-fired EGU source category. *See* 85 Fed. Reg. 31,286 (May 22, 2020) (May 2020 Rule). According to the May 2020 Rule, the residual risk assessment indicated that air toxics emissions from the source category are acceptable and that the current standards provide an ample margin of safety to protect public health and prevent an adverse effect on the environment. Further, the May 2020 Rule did not identify any cost-effective controls that would achieve further emission reductions. Accordingly, the May 2020 Rule concluded that no revisions should be made to MATS. The May 2020 Rule also rescinded the Agency's 2016 finding that it was "appropriate and necessary" to regulate HAPs from coal- and oil-fired EGUs under Section 112 of the Clean Air Act via the MATS.

In January 2021, President Biden signed Executive Order 13990, titled *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (EO 13990). EO 13990 requires agency heads to review Trump Administration actions "that were harmful to public health, damaging to the environment, unsupported by the best available science, or otherwise not in the national interest." EO 13990 contained a non-exhaustive list of the actions to be reviewed, which included the May 2020 Rule. In March 2023, EPA published a final rule that reinstated and reaffirmed the 2016 "appropriate and necessary" finding and indicated that the Agency would address the MATS RTR in a separate rulemaking. *See* 88 Fed. Reg. 13,956 (Mar. 6, 2023).

On April 24, 2023, EPA published in the *Federal Register*, at 88 Fed. Reg. 24,854, the proposed MATS Residual Risk and Technology Review that would amend the NESHAP for coal- and oil-fired EGUs. In this action, the EPA is proposing to lower the emission limit for filterable particulate matter (fPM), eliminate the total and individual non-mercury metal HAP metals emission limits, require the use of continuous emissions monitoring

[9] The CAA requires that EPA review standards such as MATS each eight years to determine if control technology has improved and if the residual emissions left after compliance with the MATS pose additional residual risk to the public. EPA recently proposed to find that, based on its review, no revisions to the MATS are required. 84 Fed. Reg. 2670 (Feb. 7, 2019).

systems (CEMS) to demonstrate compliance with the fPM standard, lower the Hg emission limit for lignite fired EGUs, and eliminate one of the two definitions of "startup" in MATS. The proposed compliance deadline for the fPM emission limit reduction and fPM CEMS is three years after the effective date referenced in the final rule at promulgation. For units that use startup definition two, they must comply with startup definition one within 180 days after the effective date referenced in the final rule at promulgation. Due to the proposed compliance dates, impacts of this action may be limited. Sherco 1 and 2 will have been retired within that compliance timeline, and King may be retired depending on the final compliance deadline. As such, impacts will be limited to Sherco Unit 3, and would include the lower fPM emission limit, the requirement to install fPM CEMS, and the elimination of startup definition two which the unit currently relies on, if the rule is finalized as proposed. Xcel Energy has worked with industry partners to develop and submit comments to further minimize the impacts of this rule on our operations.

2. Industrial Boiler Maximum Achievable Control Technology (IB MACT) Rule

In 2011, the EPA adopted emission limits for HAPs from industrial boilers and process heaters fueled with coal, biomass and liquid fuels located at major and area sources. These standards apply to biomass combustion at Bay Front Units 1 and 2 as well as to several small heating boilers located at our facilities. Compliance was required by early 2016.

EPA published a final rule revising the IB MACT rules on October 6, 2022 (IB MACT Final Rule). The IB MACT Final Rule amends the NESHAP for major source boilers and process heaters in response to three decisions by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) remanding elements of the NESHAP. The IB MACT Final Rule became effective on December 5, 2022. The rules revised emission limits for new and existing sources as well as provided rationale for the use of carbon monoxide (CO) as a surrogate for organic HAPs. All industrial boilers in the Xcel Energy Upper Midwest region that are subject to this revised IB MACT rule are able to comply with the revised requirements.

3. Stationary Combustion Turbine NESHAP (YYYY) Rule

In March 2004, EPA promulgated its NESHAP for stationary combustion turbines located at major sources of HAP emissions. The NESHAP required new or reconstructed lean premix and diffusion flame gas-fired turbines to meet a formaldehyde limit of 91 parts per billion by volume, dry basis (ppbvd) at 15 percent O_2. During the rulemaking for the NESHAP, EPA received a petition to delist lean premix and diffusion flame gas-fired turbines, and, in April 2004, EPA issued a proposal to grant the petition and delist those two subcategories of turbines. In August 2004, EPA took final action to stay the effectiveness of the standards for those two subcategories pending the outcome of the proposed delisting. EPA ultimately did not finalize the stay after the U.S. Court of Appeals for the D.C. Circuit held that EPA only has the authority to delist entire source categories under Section 112 of the Clean Air Act—not individual subcategories.

EPA did not take action to lift the stay until its proposed RTR for the stationary combustion turbine NESHAP. As part of the proposed RTR, EPA proposed to remove the stay of the standards for new and reconstructed lean premix and diffusion flame gas-fired turbines. However, when the RTR was finalized on March 9, 2020, EPA chose not to finalize the removal of the stay to give the Agency additional time to review public comments and assess new information from a 2019 petition to delist the entire stationary combustion turbine source category.

On February 28, 2022, EPA finalized the YYYY rule to amend the NESHAP for Stationary Combustion Turbines ("YYYY Final Rule") at 40 C.F.R. Subpart YYYY. The YYYY Final Rule removes the stay of the effectiveness of the standards for new or reconstructed lean premix and diffusion flame gas-fired turbines, which was issued in 2004, shortly after the original NESHAP for stationary combustion turbines was promulgated.

As a result of the YYYY Final Rule, lean premix and diffusion flame gas-fired turbines that were constructed or reconstructed at major sources of HAP emissions after January 14, 2003, must meet the formaldehyde standard once the YYYY Final Rule becomes effective with ongoing compliance demonstrated by monitoring certain operating limitations defined in the rule or by EPA approved alternate operating limitations. The YYYY Final Rule allowed the Company to propose an alternate monitoring system for the High Bridge and Riverside combined cycle units to demonstrate that formaldehyde emission standards are continuously met through continuously monitored operating parameters and required formaldehyde emission testing to validate this demonstration. After months of correspondence, EPA Region 5 approved Xcel Energy's alternative monitoring proposal on May 22, 2023, and May 23, 2023, for High Bridge and Riverside, respectively. These alternate monitoring proposals can be further amended through completion of additional source testing and approval by EPA.

VI. WATER QUALITY REGULATIONS

A. Waters of the United States

The Clean Water Act (CWA) uses the term "Waters of the United States" (WOTUS) as those waters that are subject to the provisions of the CWA. The recent Supreme Court decision in *Sackett v. EPA*[10] (Court's decision) limited the regulatory definition of those waters subject to CWA requirements. On August 29, 2023, the EPA and the U.S. Army Corps of Engineers (Army Corps), the two federal agencies empowered with implementing the CWA, announced a final rule amending the 2023 definition of WOTUS to conform with the Court's decision.

Prior to the Court's decision, EPA and Army Corps issued regulations defining categories of surface waters considered WOTUS. One category includes wetlands that have a surface and/or subsurface hydrologic connection to a surface water regulated by the CWA. The Court's decision clarified that only wetlands with an obvious surface-only hydrologic connection could be considered WOTUS and regulated by the CWA. At present, Xcel Energy does not view this change as having a significant impact on our resource plans and/or operations.

While there has been a federal change in what types of water bodies are regulated by EPA and Army Corps, state laws protecting wetlands are unchanged. These laws frequently involve a larger number of wetlands and isolated water bodies and influence our plans and operational activities.

B. Cooling Water Intake Structures

Section 316(b) of the federal CWA (316(b) rule) requires the EPA to develop regulations governing the design, maintenance, and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems) and are implemented through National Pollutant Discharge Elimination System (NPDES) permits.

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[10] Sackett v. EPA, 598 U.S. __ (2023). Docket No. 21-454. Available at https://www.supremecourt.gov/opinions/22pdf/21-454_4g15.pdf.

The EPA's 316(b) rule was finalized on August 15, 2014, requiring affected facilities to:

- Adopt one of seven options addressing impingement of biota at the entrance to cooling water intake structures, with approval by state or federal NPDES permit writers.
- Minimize entrainment of biota into the structures, as directed by the permit writer taking several factors into account.
- Implement the impingement, entrainment, and other measures as soon as practicable after the entrainment measures have been identified, with interim milestones the permit writer may set, or for new units upon commencing operations.
- Provide extensive information in permit applications, including source water physical and biological data, intake structure and system data, proposed impingement compliance methods and supporting study plans, previously conducted entrainment studies, and the operational status of the plants; and
- Provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts, with peer review of the last three, for plants that withdraw more than 125 million gallons per day.

The rule does not mandate the use of closed-cycle cooling for existing facilities. However, qualifying closed-cycle systems will satisfy the final rule's impingement and likely will satisfy its entrainment requirements. The definition of qualified closed-cycle cooling has been broadened to include existing impoundments of waters of the U.S., if sufficiently documented as having been designed to provide a recirculating cooling function or if built in uplands, and to delete references to specific cycles of concentration, percentage flow reduction, and continuous flow constraints.

The final rule requires NPDES permit writers to provide copies of applications to the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS), allowing these agencies to provide input within 60 days on endangered and threatened species and critical habitat potentially affected by intake structures and recommended permit conditions. If permit writers incorporate those conditions and permittees conduct all measures recommended by the Services, the permit will provide "incidental take" authorization. The FWS/NMFS biological opinion provided with the final rule states that the final rule is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

The definition of "existing facilities" would include nuclear uprates and other repowered and significantly modified units, even if the turbine, condenser, or fuel are replaced. However, replacement units—essentially newly built, stand-alone units constructed at existing facilities regardless of change in generation capacity, cooling water flow, or use of an existing intake structure—would be considered a "new" unit and subject to closed-cycle cooling equivalent requirements.

The final rule provides a *de minimis* exception for impingement mortality requirements for very low impingement rates but cautions that Endangered Species Act (ESA)-listed species may not be taken. The rule also provides less stringent impingement standards for low-capacity utilization units.

The final rule does not dictate an ultimate compliance deadline for all facilities but requires agencies issuing NPDES permits to include terms and conditions in permits as they come up for renewal or amendment thus final compliance is tied to the timing of future permit renewals.

Xcel Energy's Upper Midwest power plants that use greater than 2 million gallons per day of surface water are required to comply with the rule. This includes Sherco, Monticello, Riverside, High Bridge, Black Dog, Allen S. King, Prairie Island, Red Wing, Wilmarth, Bay Front and French Island. Additionally, three plants may be required to reduce entrainment mortality: Monticello, Allen S. King, and Black Dog upon NPDES permit reissuance.

The Sherco plant is already a closed-cycle cooling facility and as such, will not likely be required to make significant cooling water intake structure upgrades to comply with the rule.

The Allen S. King plant will retire at the end of 2028 and is not required to make any additional system modifications under the rule's retirement exemption provision.

Monticello's newly reissued permit includes requirements for an engineering assessment of feasible 316(b) compliance alternatives for the plant's river water intake system. The studies were submitted in January 2023 and will result in an agency decision on upgrades necessary for ongoing compliance in the next permit renewal which begins in 2025.

Prairie Island's intake system was modified in the 1990's to include necessary protections for aquatic life and shellfish and continues to be compliant with the updated 316(b) requirements.

The compliance upgrades needed for Xcel Energy's RDF plants (Red Wing, Wilmarth, and French Island) are in varying stages of implementation. The Bay Front plant has submitted the required engineering studies to Wisconsin Department of Natural Resources (DNR) for review and are awaiting a final decision on any additional changes that may be required.

C. Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs (e.g., Minnesota, Wisconsin) have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. No changes have been made to the thermal discharge temperature parameters in Minnesota.

During permit renewals for the Monticello and Black Dog facilities, EPA Region V reviewed the previously submitted thermal studies. In light of operational changes that have occurred since the original thermal studies, the newly reissued permits for both sites require a new multi-year study of the thermal discharges from both sites. Depending on the results of each study, MPCA and EPA Region V could modify each site's thermal discharge limits in a subsequent permit action. All other plants in Minnesota are unaffected by the issues that were specific to Monticello and Black Dog.

In 2010, Wisconsin implemented new water quality standards regulating the thermal discharge temperature from facilities with state issued NPDES permits. The new requirements are being incorporated into facility permits as the permits come due for renewal.

In 2012, the Bay Front plant in northern Wisconsin was the Company's first Upper Midwest plant to receive new thermal discharge limits. Preliminary modeling of the plant discharge indicated that there could challenges to meeting the new requirements. Field monitoring of the discharge showed that the plant was complying with the new thermal discharge limits during normal operations.

Currently, French Island is not subject to compliance with the thermal discharge limits. Preliminary evaluation indicates that French Island will have challenges achieving compliance with potential future thermal discharge limits during the late summer and early fall periods of the year. The current permit issued in 2018 required a thermal monitoring plan (due in 2020) with monitoring (due in 2021). Monitoring data was submitted with the permit application in September 2022. Negotiations with the Wisconsin DNR during permit reissuance will determine what, if any, thermal limits will be required.

D. Effluent Limitation Guidelines

Over the last eight years, EPA's technology-based contaminant reduction requirements Effluent Limitation Guidelines (ELGs) have undergone two major revisions and a third revision was proposed in 2023. The ELGs apply to power plants using coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills receiving coal combustion residuals. ELGs are implemented through permits issued to individual facilities and establish the maximum amount of a pollutant that may be discharged to a water body. The guidelines are periodically updated to reflect improvements in pollution control and reduction technologies.

For NSP, revisions issued in 2015 and 2020 largely targeted coal-fired electric generating units but also contained some provisions addressing wastewaters from combined and simple-cycle combustion turbines. These changes have been incorporated into individual NPDES permitted facilities compliance activities as appropriate.

On March 29, 2023, the EPA proposed additional changes to the ELGs (88 Fed. Register 18,824). The proposal suggested further restrictions on flue-gas desulfurization (FGD) wastewater and wet bottom-ash handling systems. The proposal offered options for ash landfill leachate and ash system process waters from systems no longer in use, referred to as "legacy wastewaters." The comment period on the proposed rulemaking ended on May 30, 2023, and the final rule is expected to be published mid-2024, at the earliest. The EPA also published a direct final rule, effective May 30, 2023, to extend the deadline for plants to opt-in to the 2028 early retirement provision promulgated in the 2020 regulation.

NSP's coal fired generating plants will not be required to make any upgrades to address compliance with the rule as proposed. Sherburne County Generating Plant is a closed-cycle facility that does not discharge any wastewaters associated with ash handling. Sherco Unit 3 landfill leachate may require pre-treatment or alternative management depending on what options are included in the final rule.

The method(s) used to dewater and dispose of wastewaters contained in the Sherco Unit 1 and Unit 2 scrubber solids ponds could change depending on EPA's final decision for managing legacy wastewaters. Under the 2020 ELG rule, the wastewater in the scrubber solids pond was prohibited from discharge to a surface water and prohibited from discharge to a local Publicly-Owned Treatment Works (POTW). Language in the preamble of the 2023 rule proposal suggests the EPA may be reconsidering the prohibitions for this category and has solicited public comments on options the EPA may consider in the final rule.

Retirement of the Allen S. King plant by the end of 2028 has been approved by the Commission.[11] As a result, the Company filed with the MPCA under the 2015 ELG rule for King Plant to be exempt from all ELG compliance obligations. This "Notice of Planned Participation" as it is referred to in the 2015 ELG Rule, exempted King Plant from making capital improvements needed to comply with the requirements of the 2015 and 2020 ELG rules. That same Notice will extend to the finalized version of the 2023 ELG rule proposal.

No other NSP electric generating facilities are affected by the changes proposed in the EPA's 2023 ELG proposal.

VII. COAL COMBUSTION RESIDUALS

Coal Combustion Residuals (CCRs), often referred to as coal ash, is residue from the combustion of coal in power plants. Two types of CCRs are fly ash and bottom ash. Fly ash is a light material with the consistency of talcum powder that is carried from the boiler with the flue gas. This material is captured by pollution control equipment and may be combined with solids generated from air quality control systems designed to reduce SO_x and NO_x emissions. Bottom ash consists of the heavier materials collected from the bottom of the boiler. CCRs are either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste.

Currently the CCRs resulting from the coal combustion at Sherco Units 1 and 2 are disposed of wet within a permitted, engineered, lined surface impoundment as a non-hazardous industrial waste. The fly ash generated from Sherco Unit 3 is disposed of within a permitted, engineered, lined ash landfill located on plant property. The bottom ash generated from all

[11] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E002/RP-19-368, Order (April 15, 2022), at Order Point 4.

Sherco units is stored within a lined impoundment as a non-hazardous waste until it can be beneficially used as a construction material or properly disposed on site.

The fly ash from the A. S. King plant is transported for disposal at a permitted, engineered, lined commercial landfill as a non-hazardous industrial waste, while the bottom ash from this facility is beneficially utilized in the manufacture of products. Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment, and disposal of wastes. These laws regulate CCRs as a non-hazardous waste under Subtitle D of the RCRA. While Xcel Energy's NSP-Minnesota disposal and storage facilities have been regulated by the MPCA for several decades, they became subject to regulation under EPA's CCR Rule in 2015.

EPA's CCR Rule became effective on October 19, 2015 and only applies to the Sherco and Black Dog facilities in the Company's Upper Midwest region. This rule was promulgated in response to environmental concerns regarding structural failures and releases of ash directly to the environment from large surface impoundments, allegations of inconsistent oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

The CCR rule established minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to Minnesota's current requirements under State rules, site-specific permits and operating plans, with specific differences discussed in subsequent paragraphs. Under this rule, regulated landfills and surface impoundments are referred to as CCR Units.

The CCR Rule requires ongoing groundwater monitoring of each regulated CCR Unit. The rule also defines groundwater protection standards which, if exceeded, may lead to corrective action. Currently, the results from the CCR Rule groundwater monitoring program have shown no exceedances of CCR ground water protection standards (GWPS), meaning that no corrective action is required at this time.

The CCR Rule liner performance criteria are different than that established under the MPCA's state program. Consequently, the Sherco Bottom Ash clay lined impoundment, is deemed lined under the state rule but is deemed unlined under the CCR Rule. As a result, Xcel Energy replaced this impoundment with a new, permitted, engineered, lined impoundment that meets EPA and MPCA requirements. Xcel Energy had previously anticipated the need to replace this impoundment and had plans to replace it by 2023. To comply with EPA's CCR Rule requirements Xcel Energy accelerated this project to have the new lined bottom ash impoundment in place by October 31, 2020. Closure of the existing bottom ash impoundment is scheduled to be completed as originally planned in 2025.

Coal operations ceased at the Black Dog site in April 2015. CCR discharges to the three small impoundments present at the site ceased prior to October 19, 2015. These impoundments were closed by removal on December 12, 2016. The CCR materials removed from the impoundments were disposed of in an off-site, lined landfill.
The CCR rule requires the completion of groundwater monitoring at closed CCR sites. Groundwater sampling for this site has been completed and it was determined through closure verification sampling that groundwater monitoring concentrations do not exceed the groundwater protection standards; therefore, the site meets the requirements for closure of the CCR units as documented in 2019 in the CCR Monitoring Closure Verification Report.

The EPA continues to propose changes to the CCR regulations, none of which have been finalized. In one action, the EPA proposes to add a federal permit program to the CCR regulations and in a second, separate action, the EPA proposes to regulate legacy CCR surface impoundments. Both proposals are expected to create new compliance obligations for CCR units, differing from the current rules. While these changes are likely to increase the compliance cost, accurately estimating the potential costs is not feasible or useful until the final rules are issued.

VIII. MULTI-MEDIA EMERGING POLLUTANTS: PER AND POLYFLUOROALKYL SUBSTANCES (PFAS)

State and federal efforts have been accelerating in addressing per and polyfluoroalkyl substances (PFAS), an emerging chemical of concern in the last several years. Legislative and regulatory efforts are taking place to expand the current understanding of the human health and environmental risks of PFAS and to develop steps to reduce these risks. PFAS are a group of widely-used, long-lasting chemicals that breakdown very slowly over time. PFAS are found in air, water, and soil across the world. While PFAS are not directly related to the electric power industry, there may be indirect connections through the regulation of pollutants and hazardous substances. The electric power industry, like any other industry, may have processes or use materials that could potentially contain PFAS or release them into them into the environment.

It is important to emphasize PFAS regulations have the potential to significantly impact the electric power sector by increasing operating expenses, among other challenges. If

PFAS are detected in our facilities' air emissions, water supply, or soil, costly treatment or remediation measures may be required to ensure regulatory compliance. A summary is provided below describing some of the many current federal and state efforts to regulate PFAS.

A. EPA Proposal to List PFOA and PFOS as Comprehensive Environmental Response Compensation and Liability Act (CERCLA) Hazardous Substances

On August 26, 2022, EPA issued a proposal to designate two of the most widely used PFAS- perfluorooctanoic acid (PFOA) and perfluorooctanesulfonic acid (PFOS) including their salts and isomers, as hazardous substances under Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), or Superfund. The direct regulatory impact of this designation is reporting and clean-up requirements for current or historical PFOA and PFOS releases. EPA indicated in its Spring 2023 Regulatory Agenda that it intends to issue a final rule listing PFOA and PFOS as CERCLA hazardous substances in 2024.

B. EPA's Advanced Notice of Proposed Rulemaking (ANPRM) to Regulate Additional PFAS under CERCLA

On April 13, 2023, EPA issued an ANPRM requesting public input on regulating additional PFAS chemicals (except PFOA and PFOS) as CERCLA hazardous substances. The ANPRM seeks information on designating: (1) all or a subset of seven specific PFAS chemicals—perfluorobutanesulfonic acid (PFBS), perfluorohexanesulfonic acid (PFHxS), perfluorononanoic acid (PFNA), hexafluoropropylene oxide dimer acid (HFPO-DA or GenX chemicals), perfluorobutanoic acid (PFBA), perfluorohexanoic acid (PFHxA), and perfluorodecanoic acid (PFDA), and their respective salts and structural isomers; (2) precursors to PFOA, PFOS, and the previously listed seven PFAS chemicals; and (3) "categories of PFAS."

C. EPA's Toxic Substances Control Act (TSCA) PFAS Reporting Rule

On October 11, 2023, EPA published its final PFAS reporting rule under TSCA section 8(a)(7), This rule imposes a one-time reporting obligation on any entity that manufactured (and/or imported) PFAS or PFAS-containing articles at any time from January 1, 2011 through December 31, 2022. Manufacturers (and importers) are required to report information regarding the use, source, exposure, and health effects of the PFAS they manufactured and/or imported. The effective date of the Final PFAS Reporting Rule is

November 13, 2023. The window for reporting under the Final PFAS Reporting Rule will run from November 12, 2024 through May 8, 2025.

D. National Primary Drinking Water Standards (NPDWS) for PFOA and PFOS

On March 29, 2023, EPA issued a Notice of Proposed Rulemaking (NPRM) proposing NPDWS for PFOA and PFOS and issuing a preliminary regulatory determination to regulate PFBS, GenX chemicals, PFHxS, and PFNA. As proposed the NPDWS would establish a health-based, non-enforceable Maximum Contaminant Level Goal (MCLG) of zero and an enforceable Maximum Contaminant Level (MCL) of four parts per trillion (ppt) for PFOA and PFOS. For the other four PFAS chemicals, EPA proposes using a hazard index (HI) approach, which considers the four PFAS chemicals as a mixture, and setting an MCLG and MCL of 1.0 (unitless) for these compounds.

E. Minnesota PFAS Updates

The State of Minnesota issued a PFAS Blueprint to prevent PFAS pollution wherever possible, to manage PFAS pollution when prevention is not feasible or pollution has already occurred, and to clean up pollution at contaminated sites. To do this, the state has developed multiple efforts to measure and monitor PFAS in groundwater, water, and in air emissions throughout the state.

In 2023, the Minnesota Legislature took several actions to regulate or ban PFAS in firefighting foams and in certain products.

F. Wisconsin PFAS Updates

The Wisconsin Department of Natural Resources (WDNR) has been actively developing information and tools to address PFAS contamination since 2018. In 2023 the WDNR released a PFAS contamination "toolkit" to assist communities in addressing PFAS contamination in drinking water. The toolkit provides options for actions that can be taken to identify and treat PFAS-contaminated drinking water.

G. U.S. Geological Survey (USGS) Study

On June 23, 2023, the USGS released a study of PFAS concentrations in public and private drinking water supplies in the United States. Among the study's conclusions are that as much as 45 percent of drinking water samples nationwide could contain PFAS.

IX. WILDLIFE REGULATIONS ASSOCIATED WITH RENEWABLE DEVELOPMENT

A. Land-Based Wind Energy Siting Guidelines

As part of Xcel Energy's project planning process, all renewable energy projects are evaluated following the U.S. Fish and Wildlife Service (FWS) Land-based Wind Energy Guidelines (WEGs). The WEGs have a structured process that is scaled to the specific stage of a project's development. In the early stages (referred to as Tier 1 in the WEGs), screening using available data is used to identify possible impacts over a wide area and as a result is a broad, lower resolution, analysis. As a project becomes more developed with more specific information on location and possible layout, the evaluation begins to use more site-specific data from studies targeted to the specific area(s) of a project. This "Tier 2" review develops more refined information on the plants and animals that might be impacted by the project. Additional species or habitat-specific studies may be conducted based on the results of the Tier 2 studies so that specific impacts can be minimized or avoided in the final project design, construction and/or operations.

In the latter stages of development when land for a potential facility is more fully identified, the Company works with federal and state wildlife agencies to evaluate in more detail the area where the project is expected to be constructed. These meetings and correspondence ensure that important details regarding known existence of listed species, or species of state conservation concern, are considered and, if needed, protected as we begin to design the facility layout. Site-specific Tier 3 studies are designed and conducted at this stage to inform final siting impacts. These studies evaluate wildlife use of the site and delineate habitat such as native prairie, wetlands, and forest.

Once a project has been constructed and operational, Xcel Energy implements Tier 4 of the WEGs by conducting post-construction mortality monitoring to investigate the actual impacts of the facility on avian species. These one-to-two-year studies involve surveys of selected turbines to identify avian and bat mortality across all seasons. Results from these studies are used to inform if there are unusual numbers or species experiencing mortality as a result of the wind facility's operation. In some cases, additional research (Tier 5 study) is conducted to evaluate operational changes or technology that may minimize impacts. These Tier 5 studies, when needed, are typically conducted in coordination with state or federal wildlife agencies to evaluate a specific concern.

B. Endangered Species Act

FWS reviews scientific data on plants and animals across the United States to determine if listing under the Endangered Species Act (ESA) is warranted. If species are found to meet the criteria, FWS proposes and then finalizes regulations formally listing species as either "endangered" or "threatened." The "threatened" category is reserved for species that are likely to become endangered unless steps are taken to prevent the species from meeting the criteria to be endangered. The term "endangered" means any species which is in danger of extinction throughout all or a significant portion of its range.

If a facility expects to unintentionally cause harm or death to a federally listed species, an "incidental take permit" under the ESA can be sought to provide federal authorization for that potential harm to the species. The ESA process for obtaining the take authorization involves a multi-year planning process with the FWS to evaluate the potential presence of the listed species, the modes of potential harm, and the estimated number of individual deaths over the course of the facility's operating lifetime. The permit applicant also works with the FWS to develop a plan to minimize harm and a process to mitigate the estimated deaths so there is no net impact to the species population.

Within the NSP service territory there are multiple federally listed species, and the specific species that may be present varies across our region. Because there are multiple species in the NSP service territory that are listed or proposed for listing, NSP utilizes the FWS Information for Planning and Consultation (IPaC) tool to screen planned projects for potential impacts to federally listed species. Xcel Energy also works with state-level information sources to identify potential impacts to species of state conservation concern.

Xcel Energy monitors the federal and state listing processes and utilizes qualified biological consultants to ensure we identify all relevant plant, fish, mammal, and avian state and federally listed species during the development of proposed renewable projects.

C. Bald and Golden Eagle Protection Act

Eagles are protected in the United States under both the Bald and Golden Eagle Protection Act (BGEPA) and the Migratory Bird Treaty Act (MBTA). Both of these federal laws are implemented by the FWS.

Pursuant to BGEPA, FWS has regulations that formally permit the unintentional take of eagles in the United States. In 2009, following Bald and Golden Eagles being delisted from their previous endangered status under the ESA, FWS issued regulations to permit the unintended take (or death) of eagles. The regulation has been revised twice and is currently involved in a new regulatory rulemaking. As part of FWS regulatory framework, FWS has guidance for industry on avoiding the potential for unintended take. Xcel Energy utilizes FWS guidance in project planning and when potential for eagle take is identified, we work with FWS and state wildlife agencies to address take and, if necessary, seek an Eagle Take Permit from FWS for specific projects and/or facilities.

Xcel Energy currently has two Eagle Take Permits for wind energy facilities. The Courtenay Wind facility in North Dakota has a 5-year take permit and the combined wind energy facilities of Pleasant Valley and Ben Fowke (previously Grand Meadow Wind Facility) in Minnesota are covered under a single, 5-year take permit.

With a growing Bald Eagle population in the upper Great Plains and upper Midwest, Xcel Energy continues to evaluate the risk to eagles at our existing sites as well as any newly proposed development. We work closely with the appropriate federal and state wildlife agency experts to understand the risks and potential permitting options that may be needed to address the risk of eagle take.

X. CONCLUSION

As noted in the above discussion, there are numerous proposed, pending, and existing environmental regulations which can, and do, affect the operation of our generation facilities. We are closely monitoring these regulations and compliance requirements, and we are considering the potential impacts in our planning process.

APPENDIX L – SYSTEM PLANNING INTEGRATION

I. INTRODUCTION

Achieving the goal of a sustainable, clean energy future depends upon having sufficient infrastructure to support delivery of clean electricity while maintaining customer reliability and affordability. Modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, enable customer choice, increase renewable and carbon-free energy, effectively leverage emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution and transmission systems for the needs of the future, we consider the need for thoughtful investments to meet our core obligation: safely and reliably delivering energy to our customers. We are also focused on adopting smarter technologies to further enable distributed energy resources (DER) on our system. Additionally, we face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DERs are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER impacts on the transmission grid, changes in the market and planning constructs are underway.

Recent policy changes are also driving the need to evolve resource planning. For instance, Minnesota's new carbon-free energy standard, which requires the Company to generate or procure carbon-free energy equal to 100 percent of its Minnesota retail sales by 2040, will impact resource, transmission, and distribution planning. With these recent policy changes, we are adapting our planning practices to ensure reliability and resilience, including development of substantial new transmission, which will be needed to support the transformation that is underway.

Overall, we envision building toward an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We discuss our Integrated System Planning initiative, as well as our transmission and distribution systems, in greater detail below.

II. INTEGRATED SYSTEM PLANNING

As the Company works to achieve our carbon reduction goals, we must proactively design our energy delivery system to maintain reliability and affordability and increase sustainability as generation sources shift from legacy fossil fuel plants to renewable and carbon-free sources. Investments the Company makes today will last for decades. It is therefore imperative that these investments are compatible with carbon-free legislation and regulation in addition to the Company's own goals. As both the transmission and distribution systems transform to deliver carbon-free electricity that meets the needs of an increasingly electrified grid, the Company must take a long-term approach to our planning and identify which projects will stack to reach our carbon-free goals while delivering reliable, affordable, and sustainable electricity to our customers.

This inherent need for long-term planning that considers the impacts of generation, transmission, and distribution on each other spurred the creation of Integrated System Planning (ISP). The purpose of ISP is to develop generation, transmission, distribution, and natural gas plans that deliver on the Company's clean energy goals while keeping bills low and enhancing the customer experience. ISP also bridges the gaps between modeling tools with human processes in addition to tackling the myriad challenges borne by the overall planning landscape, such as inflection points with technologies – like EVs and beneficial electrification – and pricing. The standing goal and charter of the ISP organization is to bring out the best in all of our infrastructure systems to meet the needs of our customers while preserving legislative requirements in concert with affordability.

A. Two Organizations, One System

By creating ISP, the Company has created two simplified, streamlined, and focused organizations: ISP and Operations. ISP focuses on planning the Company's electric and natural gas delivery systems. It takes an integrated approach to designing construction specs, conceptual design feasibility, regulatory and policy collaboration, and modeling and innovative technology integration to consider the entirety of the Company's energy delivery systems: generation, transmission, distribution, and gas. Each of these aspects of our system are linked, so consideration of how projects in one area impact another and function together must be taken into consideration when planning for our decarbonized future. Operations is focused on the execution and delivery. Once ISP has done its part, Operations takes care of crucial details such as safety; siting and land rights; project management, engineering, and construction; operations and maintenance; program implementation; and customer connections. The relationship between ISP and Operations is not linear, but cyclical, as handoff and communication processes are essential to its success.

B. ISP System Planning Cycle

The Company understands that to drive the transformation of strategic planning within the enterprise, ISP will need to institute a cross-functional planning cycle that will serve as a platform to achieve integration. To achieve this, a five-part System Planning Cycle has been developed.

- *Origination*

Origination focuses on customer needs evolution, emerging trends, technology integration, competitive advantage, and competition.

- *Integrated Planning*

Integrated Planning focuses on the alignment of origination trends into impact analysis, competitive advantages, and strategic system plans.

- *Modeling and Analytics*

Modeling and Analytics optimizes and refines strategic system plans based on enterprise outcomes centered on reliability, cost, sustainability, and customer experience.

- *Conceptual Design*

Conceptual Design develops and transforms integrated plans into conceptual designs, project value and costs, and enterprise capital plans.

- *Standards and Compliance*

Standards and Compliance develops, designs, and governs operational standards, project management, and compliance metrics and interfaces with regulators.

ISP Business Operations oversees this process and integrates ISP within the context of the enterprise, develops Management Operating Systems, and creates Success Paths for the ISP teams to achieve overall sustainability and customer goals. In addition, ISP Business Operations coordinates and supports the regulatory responsibility of ISP.

III. ALIGNING IRP AND INTEGRATED DISTRIBUTION PLAN

Order Point 9 of the Commission's latest IRP Order[1] states:

> *9. Xcel shall take steps to better align distribution and resource planning, including:*
>
> > *A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan [IDP].*
> > *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 capacity 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.*

In addition to the work that ISP is doing to develop infrastructure investment plans that consider generation, transmission, distribution, and gas and the impacts they have on each other, the Company is working persistently to align the IRP and the IDP. We address each part of Order Point 9 below.

A. Aligning Forecast Vintages

While forecasting plays a role in both the IRP and IDP, the processes are fundamentally different and serve disparate functions. The IRP process is a long-term (15+-year) resource planning process that has been in place for decades and is governed by established Minnesota Statutes and Rules (which result in Orders that constitute prima facie evidence in other proceedings). Similarly, transmission planning is largely governed by Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) requirements and overseen by the Midcontinent Independent System Operator (MISO). In contrast, the IDP process is nascent in comparison – intended to be informational in nature – and is based on a set of planning objectives and reporting requirements that the Commission has established on a utility-by-utility basis. Additionally, the IRP forecasts include all the states in the

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[1] ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS, Docket No. E002/RP-19-368, April 15, 2022 (IRP Order).

Company's Upper Midwest service territory, while the IDP is concerned solely with Minnesota. We discussed potential evolutions to the IDP process in our IDP filed on November 1, 2023.[2]

Another key difference between the IRP and the IDP is the time horizon and planning cycle duration and cadence. The IRP indicates size, type, and timing of resource needs over a 15-year time horizon, while the IDP shows a five-year budget of discrete projects and investments including their drivers and benefits. The five-year budget, which is used for the IDP, is built every year on the forecast from the previous fall – for example, the 2023 IDP budget was based on forecast data from Fall 2022. The reason for this is that additional steps are required to create the distribution forecast; the system-level forecasts used in the IRP cannot be directly applied to the distribution system as anticipated locations for the growth must be identified. After a location-specific distribution forecast is developed, distribution system risks, mitigations, and a 5-year budget must be developed prior to the IDP filing. This is significantly different in the IRP, where the modeling happens only three to six months in advance of the filing date every four years, meaning that the most recent and relevant forecast vintages are used. This information was presented at our IRP IDP Forecasting: Electrification and DER Workshop held with stakeholders on February 13, 2023.[3] Additional stakeholder outreach details are available in Appendix S: Stakeholder Engagement Summary.

Despite the fundamental differences between the purposes of the IRP and the IDP, there are opportunities to align some of the forecast vintages used in the creation of both. Additionally, because the distinct aspects of the Company's system – generation, transmission, and distribution – are interconnected and impact one another, we are taking distribution system additions that are selected in the IRP process into account when conducting the IDP budget forecast. We are using the same forecasts in similar ways in both the IRP and IDP to align the plans, but if a new version of a forecast comes out between the IDP forecast analysis and the IRP, it would make more sense for the IRP to use the most recent version. This issue cannot be addressed by aligning the filing date for the IRP and IDP, because, as previously mentioned, the forecast for the IDP happens at the beginning of the filing process – about one year in advance – whereas the IRP modeling happens much closer to the filing date. However, for this IRP, we were able to align several forecast vintages, as shown in Table L-1 below.

[2] Docket No. E002/M-23-452.
[3] Presentation materials were filed in Docket Nos. E002/M-21-694 and E002/RP-19-368.

Per the Commission's IRP Order we are making efforts to set the forecasts for DER consistently between our IDP and IRP. [4] Because of the modeling timeline for the IRP, finalization of the IRP models was not complete at the time of IDP submission on November 1, 2023. Table L-1 below expands on the outline of which forecast vintages were used for the various IDP and IRP forecasts that we provided in Appendix A1: System Planning of our November 1, 2023, IDP.

Table L-1: Forecast Vintage Comparison

Forecast	Vintage Reflected in IDP Corporate-Level DER Scenario Modeling	Vintage Used in IDP LoadSEER DER Scenario Modeling	Vintage Used in IRP Energy Forecast
Distributed Solar PV	June 2023[5]	June 2023	June 2023
Community Solar Gardens	August 2023[6]	August 2023[7]	August 2023
Distributed Energy Storage	September 2023	2021 IDP	Did not model in IRP
Energy Efficiency	September 2023	Embedded In 2022 Energy Sales & Demand Forecast	September 2023
Demand Response	2022	Embedded In 2022 Energy Sales & Demand Forecast	September 2023
Electric Vehicles	July 2023	2022	July 2023

B. Advanced Forecasting of DER

In our most recent IDP, the Company presented DER scenarios from our new LoadSEER tool for the first time. As we discussed in that same IDP, the Company recognized a need for and sought this new tool to aid in developing load forecast and distribution plans that would allow for enhanced analysis, as increasing penetrations of DER on the distribution system require better understanding of the conditions on that system at a more detailed level.

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[4] The Commission's latest IDP Order includes a parallel Order Point; *see* July 26, 2022 Order in Docket No. E002/M-21-694, at Order Point 4.

[5] Since the IRP covers a multistate region and the IDP is focused on Minnesota, the June 2023 forecast had WI distributed solar PV added to it for the purposes of the IRP.

[6] As new information was available, it was combined with data from the August 2023 forecast.

[7] This scenario includes a forecast for solar that will meet Distributed Solar Energy Standard (DSES), Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16, and is discussed in section II.C.7.

Adoption of DER on the distribution system is location-specific, and adoption impacts are unique to each individual feeder. To better understand the potential location-specific impacts of the DER forecast scenarios on the distribution system, the forecasts we prepared for the IDP were then allocated to the distribution system using LoadSEER. The scenarios that were created and then analyzed in LoadSEER comprise various combinations of the corporate-level DER adoption forecasts in the IDP.

One output from the LoadSEER analyses was estimated distributed upgrade costs from each of the more granular adoption scenarios. For the IRP, we leveraged these estimated upgrade costs as an approximation for estimated costs to interconnect large DER resources specifically added by the Company in coming years to comply with the Distributed Solar Energy Standard (DSES)by 2030[8].

C. Investments in Hosting Capacity

Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning, and we anticipate that it has the potential to further enable DER integration by guiding future installations and identifying constrained areas. In compliance with Minn. Stat. § 216B.2425, and by order of the Commission, beginning in 2016, we have conducted and submitted an annual Hosting Capacity Program Report each year. We submitted our most recent Hosting Capacity Program Report on October 31, 2023 (2023 Hosting Capacity Program Report). These studies show hosting capacity results at the feeder and sub-feeder level, provide an indication of distribution feeder capacity for DER, and streamline interconnection studies by helping to guide projects to places on the distribution system where there may be available capacity.

There are several ongoing projects that will assist with advancing customer-sited DER, identify interconnection points on the distribution system and necessary distribution upgrades to support continued DER development, and improve our hosting capacity program for our customers. These projects include the implementation of Foundational Updates, and the subsequent implementation of the Monthly Updates use case. Increasing the HCA update cadence from quarterly to monthly will provide developers with fresher data and increase confidence in the ability of the HCA to inform the interconnection process of customer-sited DER by working to close the delay between the data cutoff date and the publication of results. More information about the timeline for implementation and prerequisite software upgrades can be found in our 2023

[8] While data was leveraged for approximating distribution upgrade costs, it is not inclusive of any costs to the transmission system for interconnecting large DERs.

Hosting Capacity Program Report filed October 31, 2023.[9] Furthermore, the implementation of the Advanced Distribution Management System (ADMS) and the ongoing implementation of AMI will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the HCA output.

In addition to these projects, as discussed in our 2023 Hosting Capacity Program Report, we have updated our methodology that improve the tool's usefulness for identifying interconnection points on the distribution system and places where upgrades to support DER development are needed. These improvements include adding the Technical Planning Study (TPS) Capacity Utilization and adding a feeder update criterion. The TPS Capacity Utilization accounts for the remaining capacity on a feeder based on the TPS and will reduce instances where the HCA map shows more capacity than is otherwise available. The updated feeder criterion will cause feeders to be updated when their normal rated capacity has been modified. Both changes, and the other changes discussed in our 2023 HCA filing, will increase the accuracy of the HCA, and help engineers more accurately identify where there is room on the system and where upgrades are needed.

HCA also serves as a valuable input prior to the interconnection process, helping customers or developers gather information about a location before an application is submitted. Interconnection studies are necessary to ensure the proposed generator can safely interconnect without adversely impacting electric delivery to surrounding customers and at what cost. With better data inputs and more analytical tools available to distribution engineers, we will be able to respond more efficiently to interconnection study requests and streamline the process for interconnecting customers. The interconnection process and associated studies will make use of the latest in technology and standards, such as IEEE-1547-2018 as amended in IEEE-1547a-2020, discussed in further detail in the section below and align with applicable regulatory guidance developed in the Interconnection and Operation of Distributed Generation Facilities proceeding (Docket No. E999/CI-16-521).

D. Improvements in Non-Wires Alternatives Analysis

We have been continually improving and expanding our NWA analysis. As discussed in Appendix F: Non-Wires Alternative Analysis of our 2023 IDP, the stacked values used in our NWA analysis are consistent with the IRP assumptions, where applicable. Given the inherent differences in timing of the two filings and the time at which we must begin our NWA analysis, however, some assumptions align with our last *approved* resource plan but do not align with the modeling assumptions that were used in

[9] Docket No. 23-466.

this plan. For example, the WACC discount rate varies slightly; this IRP uses the WACC from the latest Commission-approved capital structure in Docket No. E002/GR-21-630, but we did not have time to make that adjustment between the time of the rate case Order and when we needed to begin NWA analysis for the 2023 IDP. In addition, the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline, from which many of our technology cost assumptions are sourced, does not reflect potential tax credits for battery energy storage. Although we made an adjustment for our IRP modeling, we did not have time to incorporate that adjustment into the NWA analysis for the 2023 IDP. We will continue to evaluate our modeling assumptions and strive to match them between the IRP, the IDP, and NWA analysis whenever practicable and applicable.

We have not yet issued market solicitations for deferral opportunities, but as discussed in Appendix F of our 2023 IDP, our latest NWA analysis shows three potentially viable and cost-effective projects. All three of these potentially viable projects have in-service dates in 2028. Given that timeline, we will have another opportunity to run our NWA analysis in November 2024 as part of our annual NWA analysis update before additional steps are taken. If any of the projects remain potentially viable and cost-effective, we would then determine next steps in the next IDP Annual Update filing in November.

E. Plans for Aggregated DERs

From a resource planning perspective, we have many DR and energy efficiency programs that can be considered "aggregated" in the sense that they are designed to benefit the bulk system at times of peak system demand. It is important to note that, in this context, "aggregated" means behind the meter resources, such as customer owned DR, EE, rooftop DG solar, and customer owned batteries. This contrasts with larger DERs that are front of the meter, such as those outlined in Chapter 136, Article 4, Section 17 of Minnesota Law.[10]

As shown in Appendix F: EnCompass Modeling Assumptions and Inputs, these behind the meter resources and corresponding assumptions about their capabilities are entered in aggregate into EnCompass for consideration. For the IRP, this includes DER in all states in our Upper Midwest region, whereas the IDP only considered Minnesota. Additional information about DER can be found in Appendix E: Load and Distributed Energy Resource Forecasting and Appendix J: Distributed Energy Resources.

[10] Chapter 136 - MN Laws.

Additional discussion about Virtual Power Plants and the potential for them to deliver benefits to the bulk system, including delivering peak-load electricity can be found in Section V of Appendix X: Advanced Technologies.

IV. TRANSMISSION PLANNING

As we discuss in Appendix T: MISO Grid Congestion, while transmission planning is considered separately from resource planning, these two functions are interrelated. Transmission limitations in turn inform our resource strategy, and transmission needs are driven by multiple factors including increased customer electric demand, new or retiring generator interconnections, generation resource choices and the availability of transmission to meet the demand for these resources. Further, the interconnected nature of the transmission system means that neighboring utilities' decisions (either transmission or generation) impact the NSP System.

A. MISO and Transmission Planning

The Transmission Business Unit centrally manages Xcel Energy's transmission systems (i.e., NSPM, NSPW, Public Service Company of Colorado, and Southwestern Public Service Company) so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party-owned) to the distribution systems serving our customers. To effectively leverage the interrelation between the transmission and resource planning functions, Transmission Planning has transitioned into the ISP organization along with Resource Planning, as discussed above.

As demonstrated in the Biennial Transmission Plan[11] we – as part of the Minnesota Transmission Owners (MTO) group – submit to the Commission in odd-numbered years, we are constantly reviewing and studying our system to optimize operations and prepare for the future. We independently – and in conjunction with MISO and our neighboring utilities – analyze different futures to assess the system and determine any necessary improvements, in both short- and long-term planning horizons. Based on these analyses and subsequent implementation, between 2010 and 2018 we invested more than $3 billion in our transmission system. Much of our transmission investment over the recent past has been in implementing the CapX2020 initiative and participating in MISO 2011 Multi-Value Projects (MVP), which increased transmission capabilities in the Upper Midwest. Expanding upon these efforts, the MISO Long-Range Transmission Planning effort has developed the first of four transmission expansion portfolios with an estimated benefit to cost ratio of 2.6-3.8 for the northern portion of the MISO

[11] Docket No. E999/M-23-91.

footprint, increasing to 2.8-4.0 when considering only the zone in which NSP is located.[12] The second of these portfolios is currently under development, being analyzed against scenarios that achieve 96 percent carbon reductions across the MISO footprint, and meeting Minnesota requirements for 100 percent clean energy by 2040.[13]

MISO and the Company perform ongoing and specialized studies to evaluate necessary projects to address issues in the overall MISO system, including the NSP System.

From these studies, and our own technical study efforts in support of the Baseload Study we undertook with this Resource Plan, as discussed in Appendix T: MISO Grid Congestion, we believe significant additional transmission development will be necessary as we and other utilities retire fossil-fuel baseload generating units and add significant renewable resources to the grid to achieve our commitment to a clean energy future. We also believe changes to the current planning constructs are necessary to accurately reflect the trends underway and to ensure system stability and resilience, customer affordability, and reliability. For instance, the Company is adding additional system reliability aspects to our RFPs to ensure grid reliability and not just capacity totals are accounted for as we transition our system to carbon-free resources.

B. Ongoing MISO Studies

MISO Transmission Expansion Plan (MTEP). MISO has an annual transmission planning process which results in identification of needed transmission facilities.

MISO Generation Interconnection Studies. MISO performs generation interconnection studies to identify facilities necessary to connect new generation resources.

MISO Economic Planning Studies. As part of its planning process, MISO conducts a Market Congestion Planning Study (MCPS). The purpose of this study is to determine whether there are transmission projects that could remove transmission constraints and thus more efficiently use available generation resources. When undertaken, the MCPS results are reported as part of the annual MTEP report. During the MCPS process, projected economic and power flow models are developed which, when analyzed, determine the total production costs that are incurred to provide energy to the MISO

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[12] MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Trance 1 Executive Summary.* https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf.

[13] https://cdn.misoenergy.org/20230428%20LRTP%20Workshop%20Item%2003b%20Future%202A%20Siting%20Presentation628726.pdf.

load. Transmission constraints – the transmission elements that limit the amount of power that can be transferred between the unused, lower-cost generation and customers – are identified. Through stakeholder discussions, transmission projects are proposed that could mitigate the constraints. The costs for these proposed transmission projects are determined and compared to the amount of production cost savings that could be realized if those projects were in service. The resultant benefit to cost ratio of the projects indicates whether the proposed solutions should be considered for further evaluation for constructability and reliability analysis. Stakeholder review and comments are compiled, and a decision on whether to recommend a MCPS project be included in the upcoming MTEP report is made.

MISO Long-Range Transmission Plan (LRTP): To meet the collective goals and requirements of the MISO footprint efficiently and cost-effectively, the LRTP was initiated in 2020. This effort is expected to analyze if there are cost effective portfolios of transmission projects in the northern portion of the MISO footprint (analyzed in Tranches 1 and 2), the southern portion of the MISO footprint (analyzed in Tranche 3), and between the two areas (analyzed in Tranche 4). The first projects included in the Tranche 1 portfolio, approved in July 2022, are expected to be placed in service starting in 2028. Like the Economic Planning process, the LRTP is subject to a rigorous stakeholder process to determine the system improvements included in a portfolio while meeting minimum benefit to cost thresholds.

C. Technical Considerations

1. *Seams*

Seams are interconnections between different regional transmission organizations/independent system operators (RTOs/ISOs), generally within the same interconnect (i.e., PJM to MISO, both of which are in the Eastern Interconnect), and they play a role in interregional planning. To address reliability issues and inefficiencies between RTOs, MISO and neighboring regions implemented interregional planning processes beyond FERC required coordination. While this process has yet to identify areas in which interregional transmission expansion would be cost effective for both regions, this foundation of interregional cooperation spurred the creation of the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) study effort, described in greater detail below.

2. *Congestion*

A thorough discussion of transmission congestion, its causes, impacts, and efforts to address it can be found in Appendix T: MISO Grid Congestion.

3. *Reliability*

In addition to ensuring reliability by meeting MISO resource adequacy requirements, the Company also conducts studies related to transmission grid reliability and essential reliability services, including grid strength and stability studies, and maintaining a transmission planning criterion. The primary goal of this reliability analysis is to ensure NERC compliance on the transmission system. These studies incorporate load growth, shifting generation, and any topology changes to ensure all planning criteria are met in the 10-year planning horizon.

While transmission reliability is focused on the larger MISO bulk transmission system, it is also being integrated into processes for acquiring future generation for the NSP system. Since many aspects of transmission reliability are locational in nature, it is particularly well suited for incorporation into the evaluation process for many of the Company's generation acquisition processes. These generation RFP processes allow for evaluation of locational factors, unlike the resource planning process generally unconstrained by interconnection location used in the IRP. The main way that transmission reliability is being incorporated into resource acquisition processes is by evaluating the attributes from different generation resource bids that are related to transmission reliability in addition to the conventional RFP evaluation process.

4. *Interconnection Queue*

The MISO Generator Interconnection Process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are several months behind due to the considerable number of projects in the queue, and a generator interconnection process that allows late withdrawals from the queue. With the intention of addressing some limitations in processing generation interconnection queues, FERC issued Order 2023 in July of 2023, directing all ISOs/RTOs to file their plans to address these issues. These compliance filings are not due until after the filing of this IRP, meaning we do not have any official updated information about MISO's plans at this time. Order 2023 includes the following provisions:[14]

- **Implement a first-ready, first-served cluster study process.** Transmission providers will conduct larger interconnection studies encompassing numerous proposed generating facilities, rather than separate studies for individual generating facilities. This approach will increase the efficiency of the interconnection process, help minimize delays, and improve cost allocation by analyzing the transmission system impacts of multiple projects at once. To ensure that ready projects can proceed through the queue in a timely manner, interconnection customers will be subject to specific requirements, including financial deposits and site control conditions, to enter and remain in the interconnection queue.
- **Speed up interconnection queue processing.** The final rule imposes firm deadlines and establishes penalties if transmission providers fail to complete interconnection studies on time, but transmission providers may appeal their penalties at the Commission. Additionally, the rule establishes a detailed affected systems study process, including uniform modeling standards and pro forma affected system agreements.
- **Incorporate technological advancements into the interconnection process.** The final rule requires transmission providers to:
    - Allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request. This reform creates a more efficient standardized procedure for these types of generating facility configurations.
    - Use operating assumptions in interconnection studies that reflect the proposed charging behavior of electric storage resources.
    - Evaluate alternative transmission technologies in their cluster studies.

  Additionally, the final rule allows interconnection customers to add a generating facility to an existing interconnection request under certain circumstances without such a request being automatically deemed a material modification and establishes modeling performance standards or inverter-based resources.
- **Establish an effective date and a transition process.** Compliance filings are due 90 days after publication of the final rule in the *Federal Register*. To smooth

[14] https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements.

the transition to the new rule, the Commission has adopted two options that can be exercised depending on the progress of the interconnection request:

- Those interconnection customers that have been tendered facilities study agreements by the transmission provider may proceed to a transitional serial study (a facilities study) or may opt to move to the transitional cluster study.
- Those interconnection customers in the interconnection queue that have not been tendered a facilities study agreement (have not completed the system impact study) will be eligible for the transitional cluster study.

While the MISO Generation Interconnection Process already includes many of these provisions to ensure timely processes of requests, the requirement to ensure projects entering the queue are "ready projects" will reduce the stress introduced by the inclusion of less certain or speculative queue requests.

Even if the aforementioned time constraints improve with queue reforms, as generation projects progress through the DPP phases, they are sometimes assigned high transmission system upgrade costs that challenge their economic viability. These interconnection costs, which are partially due to assigned transmission system upgrades, are additional to a resource's capital cost, both of which are passed on to customers.

In the MISO footprint, costs for upgrades are directly assigned to interconnecting generators, with the exception of network upgrades at 345 kV and above, for which 10 percent of the upgrade cost are regionally cost shared. To represent these upgrade costs in our last IRP, we used $500/kW for generic wind projects and $250/kW for generic solar projects, which were based on MISO Definitive Planning Process data. In this IRP, we have not yet noted significant improvements in these costs, and have decided, for modeling parity, to use a consistent $250/kW as the estimated system upgrade cost for all generic resource options, including storage. Additionally, these allocations are currently being discussed at the Federal and Regional levels in FERC Docket No. RM21-17-000, and may change based on those discussions.

The Company is looking for more efficient and innovative ways to meet our sustainability and reliability goals, including working with MISO to amend the Generator Interconnection Process, engaging with projects that will increase transmission capacity, and making decisions that will allow us to keep and reutilize existing interconnection rights. In the Company's work with MISO, two key issues with the queue were identified: (1) constraints are being identified, but not mitigated, and (2) not all constraints are being identified.

The issue of constraints being identified but not mitigated has been attributed to the threshold at which generators are made responsible for upgrade costs. The existing MISO threshold is that a five percent or greater contribution would require a generator seeking Network Resource Interconnection Service (NRIS) to pay for an identified upgrade. For a generator seeking Energy Resource Interconnection Service (ERIS), a contribution level of 20 percent or greater is required to be assigned costs of an upgrade. This gap in cost responsibility resulted in needed upgrades being identified during System Impact Study efforts, but since contribution levels of the projects were below the thresholds, the constraints were not mitigated. This was aggravated by generators being allowed to switch the level of service requested between System Impact Study phases – if a generator seeking NRIS could not cover the costs of upgrades to maintain that level of service, they were allowed to switch to being an ERIS service request between phases to reduce their cost burden, but still impact the same constraints.

In early 2022, the Company raised this concern with MISO and initiated a stakeholder process to implement our proposed solution – lowering the ERIS contribution threshold to 10 percent. MISO facilitated the stakeholder process, but implemented a change that only partially addressed the issue. MISO's solution applies a 10 percent contribution threshold for generators requesting ERIS, but only to facilities that are 230 kV and lower. Given that lower voltage facilities are higher impedance, and therefore contribute less generation, the Company feels that this is a step in the right direction, but still does not fully address the concern. We will be monitoring the contribution of ERIS requests on 345 kV facilities to determine the impact of this partial solution.

The issue of constraints not being identified was related to how MISO was implementing the fuel type dispatch that is included in their Interconnection Process procedures. This fuel type dispatch outlined how new generation should be dispatched in the System Impact Study models based on the type of generation they represent. While implementing this dispatch, the Company identified a consistent pattern in which the dispatch of existing generation of a similar type and in a similar location to a new interconnection request is lowered to accommodate the new request. This application of generation dispatch in this model effectively resulted in a net neutral change in overall generation output from an area, and fails to identify constraints that would limit outlet capability when generators of similar type and location are generating at similar levels. The reduction of available, low-cost generation out of economic order due to transmission system limitations is the definition of congestion and economic curtailment. This has several impacts:

1) Increased congestion costs,
2) Reduction in tax incentives,
3) Reduction in revenues due to reduced production because of transmission constraints,
4) Reduction in capacity value.

The Company raised this issue with MISO staff in March 2023, recommending changes to the MISO interconnection process, either through a stakeholder process or through including specific requirements in the NSP Local Planning Criteria. These recommendations include requirements for new and existing generation of similar types, located in similar locations, to be dispatched at similar levels. This would ensure existing resources maintain their deliverability and avoid future congestion. The response received at the meeting was that MISO would take the proposal back and consider it internally, but it was not likely that resources would be committed to the proposed changes.

There are, naturally, other issues that are not related to generation interconnection that contribute to constraints going unmitigated or simply unidentified. One great concern is the priority of dispatch in the MISO market. In the MISO market, there is no consideration to interconnection service when differentiating between resources in a similar location – the decision is based purely on offer price. This means that a newer wind resource that chose ERIS due to the higher cost of NRIS can offer a lower cost into the market than an older wind resource that may have less valuable tax credits or may have exhausted their tax credits, but obtained NRIS when it interconnected. This, in effect, reduces the deliverability of the NRIS resource in favor of an ERIS resource that is only supposed to be able to utilize the transmission system on an 'as available' basis. When this treatment of resources in the MISO market is paired with the generator interconnection procedures that fail to identify and mitigate constraints, the transmission system can only be assumed to have insufficient capacity, and deliverability of resources can only be expected to decrease. In terms of resource adequacy, the situation described here also reduces the overall accredited capacity in the MISO region. NRIS resources facing congestion are being curtailed so that ERIS resources can produce. As described earlier, reduction in production leads to lower capacity accreditation for the NRIS resource, but ERIS resources are not allowed to be granted capacity credit of any kind unless they obtain NRIS or transmission service. If the current MISO processes are not corrected, these issues will only lead to higher costs to customers and unrealized value of investments.

Given the state of the MISO queue, the Company is constantly reevaluating interconnection costs and looking for creative solutions to help keep costs low for our customers. In addition to advocating for procedural changes directly with MISO, as we previously discussed, the Company is also engaged in LRTP projects and looking for ways to preserve and reutilize interconnection rights we already have.

In addition to taking the necessary steps to realize the most value from existing transmission and generation facilities, the MISO LRTP project is developing plans to ensure the backbone infrastructure is in place to enable the transition to clean energy resources in a way that is efficient and cost effective. The initial portfolio, Tranche 1, was developed to address inefficiencies of the system and to meet near term goals and mitigate existing issues. The next portfolio, Tranche 2, is under development to design a backbone transmission grid capable of achieving carbon reductions estimated at 96 percent when compared to 2005 levels by 2041 across the MISO footprint. When considering the NSP area, these projects are intended to meet the requirements set in recent legislation by 2040. While this process is not intended to resolve all issues related to integration of new generation resources, it will ensure those resources can interconnect in a more efficient manner while meeting federal, state, and local requirements and goals.

Another effort underway to ensure a more cost effective and efficient approach to generation interconnection, the JTIQ study, has developed a process and transmission portfolio to address interregional constraints limiting the ability of new generation resources to interconnect in the MISO and SPP regions. The current JTIQ portfolio includes five projects, all primarily 345 kV located along the northern portion of the MISO-SPP Seam, stretching from North Dakota to Kansas and Missouri. Due to the innovative nature of this JTIQ process, applications have been submitted to the U.S. Department of Energy requesting federal funding for portions of this transmission development.

Given the increasing limitations of the MISO queue, the Company has also been looking for opportunities outside the MISO process to meet our renewable sourcing needs. One way to do this is to preserve and utilize interconnection rights we already have, thus avoiding delays and costs associated with the interconnection process. A recent success of this endeavor is the currently under construction Sherco Solar project at the site of our Sherco Coal plant in Becker, Minnesota. Because the coal plant was connected to MISO, the Company already had interconnection rights, which would have been lost, if they were not reused by 2026. By building Sherco Solar at this site, the Company secured our interconnection rights, which benefits our customers, as there will be no interconnection costs added to the capital costs of Sherco Solar.

V. DISTRIBUTION PLANNING

The Distribution system is the final link of the electric system that delivers electricity to every home and business the Company's service area. The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. We extend service to new customers or increase the capacity of the system to accommodate new or increased load, repair facilities damaged during severe weather to quickly restore service to customers, and perform regular maintenance and repairs on poles, wires, underground cables, metering, and transformers. Distribution is also at the forefront of working to transform the distribution grid to enhance its security, efficiency, and reliability, to safely integrate more distributed resources and support electrification, and to enable improved customer products and services.

The Distribution organization is one of the Company's business units whose investments and work directly impact the daily lives of our customers. As a result, it is important that our investments are focused on achieving the Company-wide priorities of leading the clean energy transition, keeping customer bills low, and enhancing the customer experience.

A. Overall Approach to Distribution System Planning

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve to analyzing future electricity *connections*, rather than just loads. The purpose of these assessments is to proactively plan for the future, maintain and improve resiliency, and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0) and *single contingency* (N-1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

B. Integrated System Planning and Distribution Planning

Achieving the goal of a sustainable, clean energy future depends upon having sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. Modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation: safely and reliably delivering energy to our customers. We are also focused on adopting smarter technologies to further enable DER on our system. Additionally, we face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DERs are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER impacts on the transmission grid, changes in the market and planning constructs are underway. Recent policy changes are also driving the need to evolve planning. The federal Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) have myriad avenues for acquiring funding and tax incentives, which will impact how the Company and the energy industry at large will proceed with planning, while the "100 x 40" law passed by the Minnesota Legislature contains a roadmap to 100 percent carbon-free electricity, which will also impact resource, transmission, and distribution planning. We are adapting our planning practices in the interim to ensure reliability and resilience, including development of substantial new transmission, which will be needed to support the transformation that is underway.

Overall, we envision continuing to build on our planning capabilities for an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We also envision a highly integrated operating technology environment.

This need for long-term planning that considers the impacts of generation, transmission, and distribution on each other spurred the creation of the Integrated System Planning (ISP) business unit within the Company, which we discussed above. The purpose of ISP is to develop generation, transmission, distribution, and natural gas infrastructure investment plans that deliver on the Company's sustainability goals while keeping bills low and enhancing the customer experience. ISP also bridges the gaps between modeling tools with human processes in addition to tackling challenges of the overall planning landscape, such as inflection points with technologies – such as EVs and beneficial electrification – and pricing. The Company's, and indeed the industry's, exploration of integrated planning frameworks is nascent and will continue to evolve and improve as we make progress toward a clean energy future and our vision to be the preferred and trusted provider of the energy our customers need.

VI. CONCLUSION

Although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like Integrated Resource Planning (IRP), charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus, distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP. Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER.

Our transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, and to deliver growing choice and increasing renewable energy. As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably deliver energy to our customers, and adopt smarter technologies to further enable DER on our system. We recognize and will continue to respond to customer interest in increased DER.

The transmission grid is also facing new challenges and opportunities as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught-up. Overall, we envision building toward an integrated grid in the future that supports the Company's clean energy transition – leveraging the strength of an interconnected system to make the best use of available resources and continue to serve our customers with resilient and reliable power.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources.

APPENDIX M – NUCLEAR

I. INTRODUCTION

Our Preferred Plan proposes to extend the operations of our nuclear plants. The continued operation of our two nuclear plants, which have been providing carbon-free power for 50 years, is crucial to achieving our Company's and Minnesota's carbon-free goals. We are proposing to extend operations of the two units at Prairie Island Generating Plant (PINGP) for an additional 20 years, until 2053 and 2054. We are also proposing to operate the Monticello Nuclear Generating Plant (MNGP) until 2050, in line with our pending application at the Nuclear Regulatory Commission (NRC). By doing so, we can continue to provide our customers with carbon-free power while keeping costs low by making use of our existing carbon-free resources.

In this appendix, we discuss the importance of using our nuclear generation fleet to meet our environmental and resource planning objectives and Minnesota's policy goals. Further, we provide information in compliance with Order Point 23 of the Minnesota Public Utilities Commission's (MPUC) last IRP Order,[1] requiring that we file a report explaining:

A. Planned investments at the Prairie Island and Monticello, and future plans for Prairie Island.[2]

B. Any aging management issues that may arise from continued operation.

C. Expectations regarding future nuclear workforce.

D. Cyber-security issues or concerns as plants move from analog to digital systems.

E. True comprehensive cost-benefit analysis, which includes potential environmental and economic impacts to the neighboring communities—in particular, the Prairie Island Indian Community and its Treasure Island Resort & Casino.

F. Additional spent nuclear fuel generated over a 10- or 20-year period.

[1] *In Re Xcel Energy's Upper Midwest Resource Plan*, Order, Docket No. E002/RP-19-368, April 15, 2022 (IRP Order).
[2] We note that where we reference plans for PINGP or MNGP beyond 2033/2034 or 2040, respectively, such plans are preliminary and contingent upon Commission approval of the life extensions and future Certificates of Need, and NRC renewal of the plants' operating licenses. We discuss required state permits, Certificates of Need, and federal licenses further in Section IX below.

G. How fuel stored on-site will be removed during the next integrated resource plan period.

H. Which additional state permits, Certificates of Need, or federal licenses will be required.

I. The full supply chain and life-cycle carbon impacts of the ongoing nuclear generation and storage at each of the facilities.[3]

We begin with a discussion of nuclear generation's role in a carbon-free future.

A. Nuclear's Role in a Carbon-Free Future

Our nuclear generation plays a key role in our carbon free future. We could not cost-effectively achieve such significant levels of carbon reduction without nuclear generation on our system. Our nuclear plants—which total approximately 1,650 MW in baseload net capacity—comprise approximately 40 percent of our existing carbon-free generation and 30 percent of our total generation in the Upper Midwest. These plants avoid the emission of 12.5 million metric tons of carbon dioxide due to reduced consumption of fossil fuels each year, which is equivalent to removing approximately 2.8 million gas-powered cars from the roads.[4] Nuclear is particularly important as we come to rely more and more on intermittent renewable resources like wind and solar. As we add significant amounts of intermittent renewable resources, the Company's nuclear plants help ensure that our system is resilient and reliable 24 hours a day, 365 days a year.

Our Preferred Plan includes a 20-year license extension of PINGP Units 1 and 2 (expiring in 2053 and 2054) and an additional 10-year extension on the operation of MNGP (through 2050). The EnCompass modeling of our plan demonstrates both that the continued operation of PINGP and the extension of MNGP are cost effective and expected to result in customer benefits. Our Economic Modeling Framework is discussed in Chapter 5: Economic Modeling Framework, but we briefly summarize the nuclear-specific results below.

As part of our economic analysis, our three baseload scenarios are based on three nuclear retirement scenarios, shown in Table M-1 below.

[3] Addressed in Appendix Y: Life Cycle Emissions Impacts.
[4] 2022 Nuclear Energy Institute data is used for MNGP and PINGP metric tons of carbon dioxide emissions avoided. Equivalent vehicle approximation calculated from August 2023 Environmental Protection Agency vehicle emissions data (www.epa.gov).

Table M-1: Baseload Scenarios

Scenario Name and Description	Plant Retirement Dates	
	PINGP Unit 1/Unit 2	MNGP
Scenario 1 – Reference Case Maintain current planned retirement dates	2033/2034	2040
Scenario 2 – Prairie Island plant Extension Extend PINGP 20 years; maintain MNGP retirement date	2053/2054	2040
Scenario 3 – Preferred Plan – Extend All Nuclear Extend PINGP 20 years; extend MNGP 10 additional years	2053/2054	2050[5]

The baseline modeling for the three scenarios described in Table M-1 is allowed to select the most cost-effective resources to replace the nuclear plants at the time of their retirements; therefore, all three scenarios assume some amount of firm dispatchable replacement generation such as gas-fired combustion turbines (CTs) to meet capacity needs. Our analysis shows that extending operation of our nuclear plants is beneficial and the least-cost alternative when compared to other scenarios. Table M-2 summarizes the EnCompass results for each modeled scenario.

Table M-2: Scenario PVSC/PVRR Deltas from Reference Case ($2024 millions)

PVSC Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
Scenario 1 PVSC	**$0**	$51,037	**$0**	$63,635	**$0**	$68,788
Scenario 2 PVSC	**($413)**	$50,624	**($437)**	$63,198	**($513)**	$68,275
Scenario 3 PVSC	**($785)**	$50,252	**($941)**	$62,695	**($1,025)**	$67,762
PVRR Production Cost	**Delta in NPV ($m) 2024-2040**	**NPV ($m) 2024-2040**	**Delta in NPV($m) 2024-2047**	**NPV ($m) 2024-2047**	**Delta in NPV ($m) 2024-2050**	**NPV ($m) 2024-2050**
Scenario 1 PVRR	**$0**	$34,678	**$0**	$44,948	**$0**	$48,927
Scenario 2 PVRR	**($97)**	$34,581	**$291**	$45,239	**$391**	$49,317
Scenario 3 PVRR	**($464)**	$34,215	**$46**	$44,994	**$239**	$49,166

5 As part of our last approved IRP, we received approval to extend operations at MNGP for 10 years. An additional 10-year extension, as modeled in the Preferred Plan, aligns with the NRC license extension we are currently seeking for MNGP. We anticipate applying for a SLR with the NRC for an additional 20-year extension for PINGP at the end of 2026.

The Preferred Plan—which includes the extension of both our nuclear plants—is the least-cost baseload scenario. The extensions result in approximately $1 billion in PVSC savings for our customers when compared to the Reference Case. We also conducted a sensitivity analysis that reoptimizes our Preferred Plan expansion plan to achieve a 100 percent carbon-free generation fleet by 2050. The results of the analysis are summarized in Chapter 5, Economic Modeling Framework. The Preferred Plan sensitivity case results in savings of nearly $2 billion for our customers on both a PVSC and PVRR basis. Compared to existing technologies, the extension of our nuclear fleet provides an overwhelmingly cost-effective source of carbon-free energy.

We believe these results provide strong support for our Preferred Plan, Scenario 3, and demonstrate the importance of our nuclear fleet from an overall resource planning perspective.

In addition, our nuclear plants provide three crucial elements of system value, all with zero carbon emissions: accredited capacity; system stability; and portfolio diversity and reliability. We address each of these elements below.

First, MISO's new seasonal resource adequacy construct has, in essence, increased the value of our nuclear plants since our last resource plan filing, most particularly in the winter season. Under MISO's new planning reserve margin (PRM) requirements, there is currently a 27 percent reserve margin during the winter months—higher than the summer season—while the winter seasonal capacity accreditation assumptions are projected to be less than five percent for new solar resources and less than 40 percent for new wind resources. To keep our system stable and meet the PRM during all seasons, we would need incremental natural gas generation if we were to replace our nuclear generation. This would slow down our efforts to cut carbon emission and reach Minnesota's goal of carbon-free energy. Given renewables' lower seasonal accreditation values, the large amount of renewables (shown below) that would be required to added to offset the loss of our nuclear plants would likely require even more transmission than the already sizeable transmission expansion plans of MISO current build out. EnCompass modeling results show that Scenario 1—replacing the carbon-free energy from the nuclear plants (based on their current retirement dates) with other resources—would require nearly 4,700 MW of incremental generating capacity over the modeling period, in addition to the resource additions identified in our Preferred Plan. Extending the lives of both nuclear plants (Scenario 3) offsets the need for more than 896 MW of firm dispatchable capacity, 120 MW of standalone storage; 2,800 MW of wind; and 876 MW of solar through 2040.

Second, our nuclear units provide vital stability for the transmission system. To determine the transmission system impacts of the nuclear plants' retirement, we conducted a "leave-behind" study. The study is provided in full as Appendix M1: NSP Nuclear Leave Behind Study Report. The study shows that the retirement of PINGP and MNGP, all else remaining constant, would necessitate significant costs in system upgrades to mitigate the resulting thermal violations on the transmission system during peak summer months. In addition, the leave-behind analysis shows that maintaining dynamic system stability in the absence of PINGP and MNGP would require significant replacement generation and load management costs. The reinforcement costs are functionally accounted for in the modeling as capital expenditure based on the timing of retirement. More details are discussed in Appendix M1: NSP Nuclear Leave Behind Study Report.

Third, our nuclear fleet adds important diversity to our generation portfolio to maintain reliability as coal is retired from our system and to provide a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of intermittent and dispatchable intermittent resource accreditation. It is also a critical piece of our reliability requirement, as it is not a fuel-limited resource, is not subject to pipeline limitations during the winter season and has a strong operating history during cold (and hot) weather events. In 2022, our nuclear fleet operated at 96 percent capacity factor while working with power marketing to flexibly operate the nuclear plants 14 times to allow for more renewable generation on the grid. To further emphasize this reliability value, our nuclear fleet operated at 100 percent capacity during a massive winter storm in December of 2022 that crossed the Dakotas, Minnesota, and Wisconsin. While this historic winter storm created crushing winter conditions including blizzards and record cold temperatures across the majority of the United States and parts of Canada, our nuclear plants continued to provide the necessary electricity to our customers to keep them warm during this heavy, intense wintery storm.

We recognize that technological developments, like energy storage, hold great promise and that reliable renewable baseload energy continues to develop, as discussed in Appendix I: Minnesota Energy Storage Systems Assessment. Like others, we are excited by storage technology and its potential to further transform our system. We are taking steps as part of this Resource Plan to ensure that we are prepared to take full advantage of better technology as we learn from our pilot programs such as the Form Energy long-duration energy storage facility pilot. As the Company continues targeted initiatives and programs to further develop and gain experience in storage technology, we recognize that this technology is not yet economically at a scale comparable to even a fraction of our nuclear fleet. For this reason, we view nuclear energy as a resource that will help facilitate our transition to even greater renewable generation and storage opportunities in the longer term, while we continue to pursue aggressive carbon reduction in the near-term.

In addition to the economic benefits identified by EnCompass modeling, our nuclear plants provide significant state, community, and employment benefits. Our nuclear operations employ approximately 1,100 staff in and around our communities with additional contractors hired during refueling outages. The plants are also an important source of tax base for their host communities, resulting in a combined total of approximately $42 million in state and local taxes annually. In total, Xcel Energy's nuclear operations contribute approximately $1 billion in annual economic benefits throughout Minnesota.[6] These and other benefits are to be quantified as part of the University of Colorado Boulder's cost-benefit analysis (CBA), which is discussed in Section II.B below.

Our nuclear plants provide wide-ranging and substantial benefits not only to our customers but also to the environment, the State of Minnesota and the broader region, and the communities we serve. The continued operation of both plants, including an additional 10-year extension of operations at MNGP and 20-year extension of operations at PINGP, is in the public interest, is consistent with Minnesota state policy, and is necessary to achieve our carbon reduction goals at a reasonable cost.

II. TRIBAL ENGAGEMENT AND COST-BENEFIT ANALYSIS

A. Engagement with Prairie Island Indian Community and Other Local Communities

Order Point 22 of the Commission's IRP Order requires that*:* "Xcel [Energy] shall immediately begin stakeholder discussions exploring the future of the Prairie Island Nuclear Generating Plant."

Prairie Island Indian Community (PIIC or the Tribe) is an important Company partner. Xcel Energy leadership meets with the Tribe regularly to discuss key issues on legislation, strategic vision, and plant performance. Our partnership with PIIC includes engaging with the Tribe on important nuclear industry topics and Tribal objectives. For example, in 2023 we organized a tour of PINGP with the U.S. Department of Energy's Transportation Core Team, at the request of the Tribe.

[6] Nuclear Energy Institute, "The Impact of Xcel Energy's Fleet on the Minnesota Economy," April 2017.

The Company has engaged extensively with PIIC since our last IRP was approved to reach agreement on annual payments to PIIC going forward. Our goal was to ensure that PIIC, which does not receive property tax payments, would receive an annual payment comparable to other communities hosting power plants that receive property taxes from the Company. These agreements resulted in passage of a statutory amendment[7] during the 2023 legislative session, providing that:

- In addition to the annual payment of $2.5 million previously required by statute, the Company must pay $7.5 million to the PIIC for each year PINGP is in licensed operation, plus $50,000 per year for each dry cask container containing spent fuel stored at the PINGP, whether or not the plant is in operation;
- The Commission shall approve a rate schedule providing for the automatic adjustment of charges to retail electricity customers to recover these payments;
- Payments shall constitute prudent operating expenses for the Company, and shall constitute consideration for any amended settlement agreement entered into between the Company and PIIC;
- The Commission's approval of a certificate of need allowing for the additional storage of spent nuclear fuel necessary for the extended operation PINGP is effective only if the governor, on behalf of the state, and the Company enter into an agreement binding the parties to the required payments and payment recovery terms above. PIIC is an intended beneficiary of this agreement and has standing to enforce the agreement; and
- These payments may be used by PIIC for any purpose benefitting PIIC. Restrictions in prior statute regarding how many acres PIIC may acquire, and that such lands may only be used for residential purposes, are removed.

In addition, the Company has worked with PIIC to support its Net Zero Project. Through 2020 legislation,[8] which the Company supported, PIIC was appropriated $46.2 million from the Renewable Development Account to implement a Net Zero Project with the goal of developing an energy system that results in net zero emissions. PIIC has used those funds thus far to support two large projects: a 5.4 MW ground-mounted solar array on the reservation, and conversion of Treasure Island Resort & Casino's heating and cooling system to geothermal.[9] These two projects, while addressing the majority of the Tribe's greenhouse gas emissions, left PIIC without a clear financial mechanism to move Tribal housing toward the same Net Zero vision.

[7] Minn. Stat. 216B.1645, Subd. 4.
[8] Laws of Minnesota 2020, Chapter 118, Section 3. See Chapter 118 - MN Laws.
[9] See Prairie Island Net Zero Project - Prairie Island Indian Community.

In response, the Company sought ways to support the net zero goal for Tribal housing while saving Tribal members money on energy costs. As PIIC's natural gas utility, we identified the Natural Gas Innovation Act (NGIA) as a suitable mechanism because it allows gas utilities to provide support for both strategic electrification and energy efficiency—the primary measures of interest to PIIC for Tribal housing.

We have included a proposed Prairie Island Indian Community Weatherization/ Electrification Pilot in our first NGIA plan, filed in December 2023. This pilot, if approved by the Commission, will conduct home energy audits, weatherize and electrify approximately 72 PIIC homes to which the Company provides natural gas service. Most are manufactured/mobile homes. The Company will work with PIIC, PIIC's contractors, and Dakota Electric Association, with PIIC serving as the project lead to ensure a seamless experience for Tribal residents. The typical project will consist of a home energy audit to assess needs, followed by a holistic weatherization/electrification retrofit effort seeking to electrify space heating and water heating end uses, along with any other end uses that are identified as candidates. The Company has proposed utility contributions of approximately $2 million to support these activities in 2025-27. PIIC meets the definition of an Environmental Justice Area in Minnesota statute,[10] and we believe NGIA provides an innovative means to support this project in ways that go beyond what the Company could do through our normal Energy Conservation & Optimization (ECO) incentives. For further details please see our December 15, 2023 NGIA Petition, Docket No. G002/M-23-518.

Likewise, we have long-standing partnerships with the City of Red Wing, City of Monticello, Goodhue County, Wright County and the surrounding communities. Our employees live and work in these areas, and we support the communities by providing vital tax base; supporting local nonprofits through grants, volunteering, and board service; and supporting economic development. Xcel Energy leadership meets regularly with local city officials and at least semi-annually with county officials. Community breakfasts are held in both Red Wing and Monticello annually and include school administrators, local elected officials, the Sheriff, PIIC, and other members of the community. Throughout the year, we meet with various community groups and organizations to share open dialogue regarding our objectives as well as to learn about the objectives and interests of our local communities. These types of events provide an opportunity for Xcel Energy to be transparent with our strategic vision—including the future of PINGP and MNGP—and hear directly from community leaders and other stakeholders throughout the region regarding what is important to them.

[10] See Minn. Stat. § 216B.1691, subd. 1 and Minn. Stat. § 115A.03.

B. Cost-Benefit Analysis

Order Point 23.E requires that the Company conduct a: *"[t]rue comprehensive cost-benefit analysis, which includes potential environmental and economic impacts to the neighboring communities—in particular, the Prairie Island Indian Community and its Treasure Island Resort & Casino."*

In response to this Order Point, the Company began by engaging directly with PIIC to determine an approach to undertaking a comprehensive cost-benefit analysis (CBA) that the Tribe would feel holistically addresses its concerns around the future of PINGP. We and the Tribe recognize that ongoing operation of the plant has both costs and benefits, and that some of those costs and benefits can be quantified in dollar terms while others can only be discussed qualitatively. The Company had several meetings with PIIC staff to discuss possible quantitative and qualitative components of the CBA, and PIIC staff conferred with the Tribal Council for its approval.

The Company and PIIC staff agreed on an approach to a CBA with four components:

- Quantitative modeling of the economic costs and benefits of different plant retirement dates (retirement in 2033/34 versus extension to 2053/54).
- Quantitative analysis of environmental externalities, i.e., the societal costs of a scenario retiring PINGP in 2033/34 and replacing its generation and capacity with other resources.
- Quantitative modeling of the economic costs and benefits of Treasure Island Resort & Casino, a large revenue generator for the Tribe and source of employment in the region.
- Qualitative narrative (developed by PIIC) on cultural, historical and other impacts that cannot be quantified.

The Tribe agreed that this approach would constitute the comprehensive view suggested by the Order. They also requested a commitment to ongoing community engagement from the Company, to help Tribal members feel more educated, better informed, and know whom to reach out to if they have questions or concerns.
The Company supports this request and commits to annual meetings with the Tribe and its members as well as quarterly meetings with the Tribe's Office of Emergency Management.

1. *Quantitative Modeling of the Economic Costs and Benefits of PINGP Retirement Scenarios*

To evaluate the economic costs and benefits of PINGP retirement scenarios, the Company engaged the University of Colorado Boulder – Business Research Division (BRD) to conduct an economic analysis using the E3+ model developed by Regional Economic Models, Inc. (REMI). REMI E3+ is a software tool that comprehensively analyzes the linkages between the energy sector, the environment, and the broader economy. The result is a comprehensive evaluation of the macroeconomic and demographic impacts of initiatives related to the energy and environmental sectors.[11]

PINGP represents a large revenue generator, purchaser of goods and services from local and non-local businesses, employer, and source of 24/7 carbon-free electricity. These benefits can be quantified using standard economic models and compared across different scenarios for the future of the plant. The evaluation of the impacts of different PINGP retirement dates is currently underway. BRD is using REMI's E3+model to analyze the net economic impact of plant retirement scenarios, comparing the Baseline Scenario from the 2019 IRP (retirement of the Prairie Island units in 2033 and 2034) to an Extension Scenario (retirement of the units in 2053 and 2054) in line with our Preferred Plan. The analysis considers operating expenditures, capital expenditures, and consumer rate costs for each scenario. Regions analyzed include Goodhue County and "Rest of Minnesota." The analysis is being conducted for the years 2024 through 2060 (extending slightly beyond unit retirement in the Extension Scenario to capture decommissioning costs/benefits and modeling end effects). Data was provided by Xcel Energy for operating expenditures, capital expenditures, revenue requirements (total and by type—residential, commercial, industrial), labor, property taxes, and other key model inputs. Inputs to the REMI E3+ model come directly from our IRP modeling software EnCompass, ensuring consistency of assumptions across the two models. BRD then compares economic costs and benefits in the Extension versus the Baseline Scenario.

Given the discussions leading up to the data sharing, the timing of the availability of the EnCompass output, BRD is still in the process of completing the study. We intend to make a supplemental filing providing the full study in the coming months. As discussed above, we are working closely with the Tribe on these efforts and they are supportive of our current timeline.

[11] https://www.remi.com/model/e3/.

2. *Quantitative Analysis of Environmental Externalities*

The Company will use EnCompass to determine the change in emissions if the PINGP units retire and are replaced with other resources. Any increase in emissions in this scenario, relative to the Extension Scenario, will be assigned the Commission's approved CO_2 regulatory costs and externality values for greenhouse gases and criteria pollutants. The cumulative externality costs in the Extension Scenario, less those in the Baseline Scenario, represent the net societal damages incurred by retiring PINGP in 2033/2034 -- or stated another way, the societal benefit of avoiding those same emissions by continuing to operate the plant to 2053/2054.

This component of the comprehensive CBA will be included in our forthcoming supplemental filing.

3. *Quantitative Modeling of the Economic Costs and Benefits of Treasure Island Resort & Casino*

Treasure Island Resort & Casino (TIR&C) represents a significant revenue generator for the Tribe, funding a wide array of services provided by the Tribal government as well as per capita payments to each Tribal member. TIR&C is also a purchaser of goods and services from local and non-local businesses and a large employer in Goodhue County. As such, the economic benefits of TIR&C—and conversely, economic losses if TIR&C were to reduce operations or close—can be quantified using similar modeling techniques as for PINGP retirement scenarios.

BRD is using the E3+ REMI model to analyze the gross economic benefits associated with TIR&C operations that would be foregone should TIR&C close. Regions analyzed include Goodhue County and "Rest of Minnesota." The analysis period begins in 2018 and extends through the year 2023, for a six-year analysis that includes some years reflecting a pre-pandemic level of TIR&C operations. Data was provided to BRD by PIIC under a non-disclosure agreement, including current and projected spending, operating expenditures and capital expenditures, employment and salaries.

We intend to include the TIR&C study with our supplemental filing.

4. *Qualitative Narrative on Cultural, Historical and Other Impacts of PINGP Operations*

While models like REMI and EnCompass are useful tools to estimate and quantify in dollar terms some of the costs and benefits implicated in decisions about PINGP and

TIR&C, both the Company and PIIC recognize that the models cannot fully capture all of the costs and benefits. PIIC is drafting a narrative on historical and cultural values impacted by decisions around the future of PINGP. This will be included in our supplemental filing.

III. PERFORMANCE AND PLANNED INVESTMENTS

A. Operational Excellence

The future of our nuclear fleet and our carbon reduction goals depends on our ability to deliver exceptional performance at a reasonable cost. Since our 2019 Integrated Resource Plan, we continue to challenge the way we do business with the goal of improving efficiency and, therefore, cost. Xcel Energy understands that, over the past year, our performance is not at the level we desire or that we have achieved in the recent past. The Nuclear Business has evaluated its performance with the assistance of third-party consultants with expertise in both nuclear operations and leadership acumen. The leadership team has refocused the nuclear organization on leadership behaviors, standards and equipment reliability. We anticipate that the evaluation of our performance and implementation of a revised performance improvement strategy as we enter 2024 will secure and maintain our top industry performance as a leader in the commercial nuclear industry. We continue our work with the Institute of Nuclear Power Operations (INPO), Nuclear Energy Institute (NEI), and Electric Power Research Institute (EPRI) to evaluate and incorporate industry learnings and best practices to ensure continued operation on a more consistent, efficient, and safe basis.

1. Safety

Safety is a key value for Xcel Energy and imperative at our nuclear plants. The NRC Reactor Oversight Process classifies U.S. nuclear reactors into various nuclear safety "Columns," which range from 1 (best) to 5 (worst). Both MNGP and PINGP are Column 1 plants with all green safety performance indicators. And while no plant can achieve the standards of perfection imposed by the NRC at all times over its operational life, our track record demonstrates the Company's longstanding commitment to nuclear safety. Further, Xcel Energy has implemented a new approach to safety, which provides a platform for field supervisors and workers to discuss potential risk of planned work and incorporate lessons learned from past work activities. Open dialogue is encouraged between all employees to ensure every work plan is written for a successful and safe outcome. As a result, employee engagement and ownership of individual safety has improved. The Nuclear business unit documents all safety issues and identified risks through our corrective action program, as required per 10 CFR 50 Appendix B, to ensure resolution is taken. This is also a focus for the organization during outages. For example, in 2023 during the MNGP refueling outage, 100 percent of the safety issues identified were resolved.

Additionally, employees turn to technology to reduce risk and improve safety. Notably, the Company's Nuclear Innovation Team has contributed to improving safety through the use of robotics. Throughout the nuclear fleet in 2023, 32 robotic missions were executed. In one example, a robot was used at MNGP to inspect a pipe that would have otherwise required a worker confined space entry and in another at PINGP, a drone was used to inspect a lightning arrestor, eliminating work at heights. Additionally, there have been multiple examples in 2021 and 2023 at PINGP of the Company using a submersible to inspect equipment in intake bays which would otherwise have required a diver to perform. These are just a few of the examples of how the Company and its employees are pursuing the use of technology to improve worker safety.

2. *Capacity Factor and Flexible Operations*

With respect to plant availability, MNGP achieved an average capacity factor of 95 percent between 2020 and 2022. Likewise, PINGP achieved a combined average capacity factor of 95 percent between 2020 and 2022, including a 99.8 percent capacity factor for Unit 1 in 2021 and a 99.9 percent capacity factor for Unit 2 in 2022. This data reflects strong performance at both plants, and the availability of our plants drives substantial customer benefits by maximizing the value of the fixed costs associated with nuclear operations. Contributing to these capacity factors was improved performance during plant refueling outages, which were completed on time and on budget. A refueling outage of less than 30 days is considered good performance in the nuclear industry. This assumes a basic refueling outage and no major projects are scheduled. For example, in 2019 and 2021, PINGP's Unit 2 achieved a 27 and 29-day refueling outage, respectively, and in 2020 and 2022, PINGP's Unit 1 achieved a 28 and 27-day refueling outage, respectively. Likewise, we have experienced some of the longest runs of uninterrupted operation in the history of our nuclear fleet, including a record-setting 670 days at PINGP Unit 1 from 2018 to 2020, and a record-setting run of 704 days on Unit 2 from 2019 to 2021. MNGP experienced a record-setting run of 705 days from 2019 to 2021.

In addition to providing the carbon-free baseload energy we have relied upon for 50 years, we are also operating our nuclear units more flexibly. Historically, our nuclear plants were generally offered into MISO as "must-run" resources that did not respond to expected inter-day fluctuations in net load. To accommodate more variable renewables on the grid, since 2019 we have been honing our operational strategies that allow us to offer the plants into the MISO Day-Ahead market on an economic basis, allowing for MISO to schedule a portion of the plants to be more responsive to market signals and ramp output accordingly. With flexible power operations capabilities to all three nuclear units, we can safely and efficiently ramp up to approximately 280 MW– or over 15 percent – of our nuclear capacity in response to the market. In fact, the Company flexibly operated our nuclear plants 14 times in 2022 and 16 times in 2023. This capability can help us integrate more renewables on our system, while still utilizing our nuclear fleet as a carbon-free, stable, and reliable source of energy. In short, our ability to make renewables and nuclear work together helps us increase the amount of clean energy we can provide our customers.

Nuclear has proven its value as the foundation of our baseload fleet, and its carbon-free generation make it a critical part of our plan to achieve an 80 percent reduction in carbon emissions by 2030. We view flexible power operations as an expansion of nuclear's role in our fleet and in the Company's efforts to integrate substantial amounts of renewable additions during the planning period.

3. O&M and Production Costs

These safety and operational results have been achieved without increasing our production costs. In fact, both O&M and total production costs at our plants have decreased in recent years. Total actual O&M costs for our nuclear fleet between 2019 and 2023 was $186 million less than what was estimated in the 2019 IRP for O&M costs between 2019 and 2023[12]. In 2023, O&M costs totaled approximately $268 million. The Company's Nuclear O&M forecast between 2024 and 2028 ranges from approximately $274 million in 2024 to $288 million in 2028. Normal inflationary increases are contributing to the forecasted increase in O&M costs.

Between 2019 and 2023, we have consistently maintained production costs at $31.25 per megawatt-hour (MWh) or less, which is a decrease of more than 20 percent when compared to 2013 production costs.

[12] For a more like-for-like comparison of cost projections to the 2024 Preferred Plan, nuclear O&M and capital cost inputs for Scenario 7 of the 2019 IRP model were used for this comparison. Scenario 5 of the 2019 IRP was the selected scenario which modeled PINGP retiring at end of current license in 2033/2034 and MNGP license extension to 2040. The 2024 Preferred Plan models operating extensions of both plants with PINGP to 2053/2054 and MNGP to 2050. Scenario 7 of the 2019 IRP was used in this comparison because it most closely modeled the 2024 Preferred Plan with PINGP operating extension to 2043/2044 and MNGP extension to 2040.

Contributing to these results has been Xcel Energy's commitment to driving improvement through efficiency and technology initiatives, which focus on process refinement and the integration of technology to achieve efficiencies. Industry experience shows that successful nuclear organizations are highly process and outcome driven and that focused process improvement has the benefit of driving down costs while at the same time improving plant performance. Through our work with external consultants and INPO, we have been able to effectively improve upon a number of processes and personnel behaviors that has enabled the plants to achieve better results with fewer resources. We also continue to efficiently share our maintenance and operations resources between both plants and integrate these department resources as necessary to efficiently and safely maintain and operate the plants. As we move into 2024, we will continue to look for these opportunities to gain efficiencies while also using these resources to improve equipment reliability to ensure the continued safe and reliable operation of our nuclear fleet for years to come.

Notably, the Inflation Reduction Act (IRA) includes a production tax credit (PTC) for zero emission nuclear generation. As with other PTCs generated by the Company's resources, we intend to return the value of the nuclear PTCs, less any transaction costs associated with applicable tax credit transfers, to our customers in a timely manner. That said, forecasting the value of the PTCs is challenging because it is likely that the value of the PTCs will be an annual calculation based on Locational Marginal Pricing (LMP) that occurs in the market in a given calendar year.

For purposes of EnCompass modeling, we included an estimated value of nuclear PTCs in alignment with LMP assumptions used in the model and the nuclear plant dispatch resulting from the model. The value of the PTCs was added back into the model as a fixed amount. This resulted in close to $900 million total PTC amount on a NPV basis between 2024 and 2032. We assume the PTC will end in 2032,[13] hence it does not affect the cost benefit analysis of the nuclear extension scenarios.

4. *Capital*

We have completed a reanalysis of our long-term capital budgets for both plants, and we have made changes to our capital forecast relative to our 2019 resource plan. In 2019, we stated we were in a position to materially reduce our capital forecasts. The actual results validate that, between 2019 and 2022, we reduced our capital spend. In the

[13] IRA Section 13105 addresses a "zero-emission nuclear power production tax credit" in Section 45U of the Code (the Nuclear PTC). The Nuclear PTC is available for existing operating nuclear facilities in the taxable years after December 31, 2023 and prior to December 31, 2032.

2019 IRP, a four-year capital forecast between 2019 and 2022 was approximately $413 million. Actual capital spend during this time period was approximately $409 million. In 2023, unforeseen operational impacts resulted in higher capital expenditures of approximately $200 million (compared to the original forecast in the 2019 IRP of approximately $127 million for 2023). Contributing to the higher capital spend were emergent (i.e., unexpected) equipment reliability needs that resulted in loss of generation. Additionally contributing to the higher capital expenditures since 2019 is recently identified industry operating experience requiring PINGP to inspect and replace radial and clevis bolts on the Unit 1 reactor vessel.

In the 2019 IRP, assuming the scenario of 10-year extensions for both MNGP and PINGP (to compare the most like-for-like scenarios), we stated that between 2024 and 2028, we forecasted to spend approximately $559 million in capital. A reanalysis of our operational needs indicates an increase to that forecast of approximately $197 million between 2024 and 2028 for a total of $756 million over the next 5 years. Contributing to the increase are reliability projects that have been identified to support extended operation of both MNGP and PINGP to 2050 and 2053/2054, respectively. Some of these investments are discussed further in Section 4.B, "Planned Investments." Also contributing is a MNGP turbine digital control system upgrade due to current and near-term equipment obsolescence issues (i.e., equipment is no longer supported by vendor and maintenance is not possible or cost is not viable). In some cases, such as with a digital system, we are notified by the vendor that they will no longer support a specific version of the digital software and associated components and the risk to maintain the system becomes too high, so replacement is the most cost effective and lowest risk option. Security and facility expenses have also contributed to the cost increase. For additional investments, refer to Section 4.B.

The updates to our forecast reflect several years of work by numerous Company employees and leadership, as well as a recognition that we had to re-envision our approach to nuclear operations if our plants were going to remain competitive. The forecasts are based on a detailed, long-range capital budgeting process that was undertaken following our last Resource Plan. In fact, this effort included an analysis of operational and equipment reliability needs required by both plants in support of license extension plus 20 years, should approval be received at the state and federal levels. As part of this process, teams from nuclear engineering and capital projects assessed the condition of our plants and developed a long-range project forecast to support continued operations and aging management. These teams then worked with nuclear finance to develop budgets to support project needs, and probabilities were assigned to the various projects reflecting the likelihood each would be necessary to maintain the reliability of our plants. Just as we did in developing the 2019 IRP, we then worked with independent consultants with expertise in nuclear operations who assessed both our budgeting process and our capital budgets in order to ensure that our forecasts were reasonable and aligned with industry norms.

We recognize that our stakeholders and the Commission will continue to monitor our performance and investments relative to our forecasts. We look forward to demonstrating that our nuclear plants can continue to drive both environmental and operational performance and benefits for our customers.

B. Planned Investments

Order Point 23.A of the Commission's IRP Order requires the Company to explain "[p]lanned investments at the Prairie Island and Monticello, and future plans for Prairie Island."

In this section, we address planned investments at PINGP and MNGP. Future plans for MNGP and PINGP are addressed specifically in section IX: Future Plans and Additional State and Federal Processes noted below. The portfolio discussed in the next sections will reach approximately 70 percent of projected capital spend in 2036, prioritizing asset management and equipment reliability as we enter the license extension period at both MNGP to 2050 and PINGP to 2053/2054.

1. Near-Term Planned Investments

In 2024 through 2028, the Company is planning for $756 million (excluding fuel reloading) in capital investments at MNGP and PINGP.

Approximately 50 percent of these projects address equipment reliability (i.e., aging management) concerns. At MNGP, several of the largest projects in the five-year capital investment plan at MNGP address equipment reliability, including:

- turbine digital control system upgrade,
- residual heat removal motor replacements
- reactor control rod drive rebuilds and replacements,
- refueling bridge upgrade
- turbine valve replacements,
- 4 kilovolt breaker replacements,
- valve packing gland replacements, and
- intake traveling screens and trash rake replacements.

At PINGP, several of the largest equipment investments in the five-year capital plan, include:

- reactor vessel baffle former bolt inspections and replacements,
- reactor vessel clevis bolt inspection and replacement,
- fuel handling crane controls replacement
- plant monitoring system upgrade,
- reactor vessel control rod position indication upgrade,
- fire protection system upgrades,
- water treatment modification,
- inverter replacements,
- nuclear instrumentation system upgrade,
- plant traveling screen replacement.

The above listed equipment reliability investments have been identified through implementation of life cycle and aging management practices. These practices consist of monitoring and managing the effects of aging on equipment through industry established methods of monitoring, detecting, and preventing. Via the application of these methods in addition to the review of industry operating experience and lessons learned, these investments have been identified as those that are important to the continued reliable and safe operation of the plant. While the listed projects do not include all of the current equipment reliability investments, they make up approximately 85 percent of all equipment reliability projects in 2024 through 2028.

The remaining 50 percent of the $756 million five-year capital budget includes:

- MNGP and PINGP SLR projects,
- dry fuel storage projects at both plants including ISFSI expansion and dry fuel storage system procurement and spent fuel loading,
- blanket capital investments such as maintenance for tools, facility infrastructure upgrades such as training center and service building rest room upgrades and HVAC replacement, and regulatory or mandated improvements resulting from inspections or other regulations,
- miscellaneous security investments such as security specific equipment and tools, IT software upgrades for the plant monitoring system and security system computer, and
- training tools and facilities.

These investments provide a supporting infrastructure to continued operation of the plant with a focus on subsequent license extension, continuing dry fuel storage, regulatory improvements, and updates to work areas and training facilities for employee comfort and support.

2. *Long-Term Planned Investments*

If the Company were to operate both MNGP and PINGP for 20 years beyond the end of their current Nuclear Regulatory Commission (NRC) operating licenses, we estimate approximately $2 billion (excluding fuel reloading) in total capital investments at the plants. Approximately 60 percent of these projects address equipment reliability (i.e., aging management) concerns. At MNGP, large equipment reliability investments include the following:

- traveling screen replacements,
- low pressure turbine rotor replacements,
- turbine valve refurbishments,
- Turbine controls upgrade,
- motor generator set replacement,
- generator stator connector ring replacement,
- reactor manual control system upgrade,
- transformer replacements,
- radiation waste controller upgrade,
- safety injection system cable replacements,
- main condenser nozzle replacement and reinforcement,
- Environmental Qualification (EQ) Program component upgrades (these are components that are in areas of the plant that might be exposed potentially to high temperatures and, therefore, they are tested at higher temperatures before being installed at the plant),
- system and component automation upgrades,
- digital feedwater control system upgrade,
- control rod blade replacement, and
- control rod drive rebuilds and replacements.

PINGP additionally has large equipment reliability investments planned and some of these contributing to the $2 billion include:

- low pressure turbines refurbishment and rotor replacements,
- high pressure turbine refurbishment and rotor replacement,

- turbine valve replacements,
- generator step-up transformer replacement/refurbishment,
- traveling screen refurbishments,
- cooling tower vertical support upgrade,
- digital electro-hydraulic turbine control system upgrade,
- main condenser dog bone and steam bellows replacement,
- main condenser partial tube replacements,
- feedwater heater retubing, load sequencer replacement,
- fire protection system upgrades,
- underground cable replacement,
- low voltage switchgear replacement,
- transformer replacements, breaker panel replacements,
- inverter replacements,
- system and component automation upgrades,
- piping replacement,
- buried fire protection pipe upgrades,
- neutron flux mapping system upgrade,
- containment fan coil units face replacements,
- refueling bridge replacement,
- residual heat removal heat exchanger refurbishments,
- emergency diesel generator and supporting equipment upgrades,
- area radiation monitor replacements,
- cooling water header and piping replacement, control room chiller refurbishments,
- reactor coolant pump seal replacements,
- control rod position indication system upgrade,
- control rod assembly replacement,
- nuclear instrumentation system replacement,
- heating boiler replacement,
- in-core cooling monitoring and reactor vessel level indication system upgrade, and
- radiation protection equipment upgrades.

Although these projects do not make up the entire list of future capital equipment reliability investments, they do make up approximately 89 percent of the planned equipment reliability related investments.

As previously stated, the above listed equipment reliability investments have been identified for future upgrade or replacement through implementation of life cycle and aging management practices and are important to the continued reliable and safe operation of the plant.

The remaining 40 percent of the $2 billion long term capital investments includes:

- PINGP SLR,
- dry fuel storage projects at both plants including ISFSI expansion and dry fuel storage system procurement and spent fuel loading,
- blanket capital investments such as capital maintenance for tools, facility infrastructure upgrades such as plant laboratory upgrades, and regulatory or mandated improvements resulting from inspections or other regulations,
- miscellaneous security,
- IT, and
- training tools and facilities.

IV. AGING MANAGEMENT

Order Point 23.B of the Commission's IRP Order requires the Company to explain, "[a]ny aging management issues that may arise from continued operation."

Throughout the years of operation, aging of plant equipment can occur due to varying processes or mechanisms. Varying temperatures, pressures and flowing water are all examples of mechanisms that can impact structures and components gradually over time. If unmonitored or unaddressed, these aging effects could cause a component to lose its intended function or design purpose prior to the end of its life.

Through industry aging management and life cycle management best practices and station procedures, the Company continues to monitor the reliability and health of the equipment at both plants. Through these processes, the Company has identified opportunities for equipment refurbishment, replacement, or upgrade at both MNGP and PINGP, should both facilities operate 20 years beyond the end of their current NRC licenses. The equipment reliability investments previously listed fall into the category of aging and life cycle management. The Company's aging management program (AMP) applied at both MNGP and PINGP will continue to be rigorously implemented to ensure any aging management issues are identified, addressed, and repaired in a timely manner commensurate with risk. AMPs are a collection of activities involving monitoring, detecting, and preventing. These are governed by administrative controls and procedures that adequately manage the effects of aging on structures and components. This is a process the industry and company has implemented over the past approximately 50 years of the life of the plants and would continue over the next 10 years and 20 years at MNGP and PINGP nuclear plants, respectively.

In addition to being required per the plants' current licensing basis, as part of SLR implementation, AMPs are required by NRC regulations.[14] NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," provides the NRC staff's generic evaluation of plant AMPs and establishes the technical basis for their adequacy. As an SLR applicant, the Company evaluates current established AMPs and compares them to the GALL-SLR Report. A feasibility study will be performed as part of the SLR project for PINGP to determine if any major assets require replacement or refurbishment as part of the aging management program in addition to what has already been identified. This was done for MNGP's SLR application (which is a 20-year operating license extension request with the NRC) and no major investments were identified beyond what the station had already identified for equipment reliability improvements.

V. NUCLEAR WORKFORCE

Order Point 23.C of the Commission's IRP Order requires the Company to explain "[e]xpectations regarding future nuclear workforce."

Minn. Stat. § 3.8851, subd. 4 requires the Company to submit to the Commission updates periodically, with the resource plan filing, of the Worker Transition Plan (WTP) required under Minn. Stat. § 116C.772, subd. 3. The WTP is required to address the event of a shutdown of PINGP for longer than six months.

We address both requirements in this section.

A. Future Nuclear Workforce

At the Xcel Energy enterprise level, People & Organizational Health is a marquee initiative, through which we aim to have the innovative, inclusive culture and diverse, high-performing talent to lead the energy transformation within our industry. Maintaining a skilled and engaged workforce is one of the Company's top priorities as it impacts cost, performance, and safety. Specifically, continued operation of the plants requires a specialized workforce and talent pipeline. For decades, we have

[14] 10 CFR 54.

successfully and strategically managed our nuclear workforce to ensure safe, efficient plant operations.

In this section, we discuss our current nuclear workforce and how we are maintaining and planning for the future workforce needs to support continued operations of both plants.

1. *Our Current Nuclear Workforce*

As shown in Table M-3, 1,105 employees work at, or in support of, Xcel Energy's nuclear plants including contract security employees. The numbers in Table M-3 do not include other contract employees.

Table M-3: Xcel Energy Nuclear Workforce (As of December 2023)

	MNGP	PINGP	Corporate (Minneapolis Headquarters)	Total
Bargaining (includes contract security)	278	391	5	**674**
Non-bargaining	166	148	117	**431**
Total	**444**	**539**	**122**	**1,105**

2. *Maintaining Our Nuclear Workforce: Workforce Supply, Demand, and Development*

We have created a robust internal succession plan and achieved significant depth in our staffing. We also have a retention plan to ensure continuity of our bench strength. Maintaining a qualified and engaged workforce, however, remains an ongoing priority, and one that all high-performing nuclear organizations view as critical to maintenance of the industry's high standards of performance and safety. As a result, the Company must continue to create staffing pipelines that sustain the supply of qualified licensed-required positions such as operators, radiation protection technicians, and instrumentation and control technicians. Since the extended time for training to meet regulatory qualification expectations for these roles can be up to two years, these pipelines have to be in active hiring mode continuously each year. With the industry being more than 50 years old, many experienced nuclear personnel are well along in their careers and will be in a position to retire in the next five to 10 years. The supply of possible nuclear employees is becoming more limited, so it is important that the Company maintains a robust talent pipeline through recruiting, engagement, training, and active succession planning.

We have five critical pipelines for roles within the nuclear organization:

- Chemistry
- Engineering
- Instrument & Controls
- Radiation Protection
- Reactor Operators/Senior Reactor Operators

These highly specialized roles will remain crucial to the ongoing successful operation of both plants into the coming decades. As we discuss below, our practices seek to ensure a robust talent pipeline for the near and long term.

a. Recruitment

Company-wide, Xcel Energy's talent acquisition team attends over 100 recruiting events each year, posts all jobs on hundreds of online job boards, and conducts outreach to high schools, diversity groups and chapters, workforce centers, veterans' groups, and more. For the Nuclear organization specifically, our need for highly specialized workforce requires additional, targeted recruitment practices to attract qualified candidates in a competitive labor market. Other nuclear plants in the U.S. and around the world as well as advanced nuclear companies are competing for a limited talent pool, and newer industries such as data centers often recruit similarly skilled candidates as they expand their strategic vision to advanced nuclear technologies for additional generation needs.

With one in 10 new Xcel Energy hires being veterans, we recognize the value military service brings to our workplace. In addition to Xcel Energy's enterprise-wide talent recruitment practices, the Nuclear talent acquisition team maintains relationships with the U.S. Navy, which operates nuclear-powered vessels. We use the Troops to Energy Jobs site, which connects veterans with careers in the energy industry and provides further training and support for energy jobs; Hiring our Heroes, a nationwide effort to connect veterans, service members, and military spouses with meaningful employment opportunities; and DOD Skillbridge, a program that supports transitioning service members through fellowships. We also advertise nuclear job postings on websites such as Nukeworker and Facebook's Navy Nuke Job Finder, in addition to hundreds of other online job boards.

As the need for a skilled workforce remains for our nuclear plants, the retirement of our coal fleet, by the end of 2030, will create new opportunities for our employees at the Sherco and King plants. Over the past five years, approximately 15 coal plant employees have transferred to our nuclear plants, and we anticipate that over 300 jobs will be open at our nuclear plants in the 2027-2030 timeframe. Our Energy Supply and Nuclear leaders have been meeting with Sherco and King plant employees individually and presenting at plant employee meetings regularly to discuss opportunities at the nuclear plants. We discuss our workforce transition plan further in Appendix O: 2023 Workforce Transition Plan Summary and Appendix O1: 2023 Workforce Transition Plan.

The compensation levels necessary to recruit and retain experienced nuclear employees are increasing due to the limited number of nuclear plants in the United States and the highly competitive practices employed by other nuclear companies in pursuit of the same experienced personnel. To ensure we remain an employer of choice, a deliberate compensation philosophy is required.

A dedicated Compensation team at the Company manages overall compensation guidance and review and set salary structures and grades. Within those structures, managers set employee pay based on performance, anticipated contributions, internal equity, and their position within a salary range. When a job description or role profile is created, the compensation team identifies the relevant labor market for recruiting and retention purposes, in which workers compete for jobs and employers compete for workers. If available, we use market data to inform compensation. The nuclear industry standard compensation benchmarking survey is the Willis Towers Watson Energy survey. Xcel Energy Nuclear positions are matched to the market median, or 50th percentile. The Compensation team also leverages a membership through the Nuclear Human Resource Group (NHRG) for survey participation and industry peer benchmarking. Not all jobs have exact market matches. For these jobs, a "blended match" may be considered, which means compiling data for multiple job matches and averaging them together. The Company's compensation team also reviews all positions to balance external competitiveness with internal equity.

Some nuclear employees in Maintenance, Operations (including radiation and chemistry), and Engineering are also members of unions or are considered bargaining employees. The Company understands the important role these employees have in ensuring safe and successful operations of our nuclear facilities and, therefore, the

Company has worked to build a healthy relationship with our local unions over the years. The dedicated Compensation team described previously would be engaged in much the same way when renegotiating union contracts to ensure a fair and equitable offering for our bargaining employees.

b. Training & Retention

Employee retention is a crucial component of the future nuclear workforce. We employ a number of tools and programs to retain and engage employees, but challenges exist. Given the nuclear industry's openness in sharing issues and their resolution, plants with new performance issues are able to identify and recruit personnel who have worked at other plants who have successfully resolved issues. Our plants have performed well, which makes our employees desirable candidates to other utilities that are seeking to improve their performance, as our employees have demonstrated ability to operate successful plants. These other companies are offering signing bonuses and retention incentives to attract and retain experienced employees from other nuclear companies. We need to ensure that we are providing adequate pay, training, and opportunities to attract and retain the caliber of workers that we need to continue to operate at our current high level. Talent development, including fostering a culture of continuous improvement, is a constant focus for the Nuclear organization, and an essential element to achieve our performance objectives for our stakeholders.

We have incorporated retention provisions in our employee agreements to help attract and retain qualified personnel and have taken other steps to attract and retain the right skilled workforce at our plants; including the planned development of new, multi-skilled union positions.

To create a pipeline of leaders in Nuclear, we have a consistent, integrated, and sustained approach toward employee development. Xcel Energy has a cyclical Talent Review & Succession Planning approach. Human Resources, in partnership with Nuclear leaders, establish and communicate the strategy for developing high potential and succession candidates. This incudes identifying critical positions and identifying individuals for the succession plan. Those identified on the succession plan are made aware of their placement on the succession plan, are required to have a development plan, and engage in quarterly discussions with their leader about their plan and progress. We work to ensure that employees are involved and take ownership in their career development. Senior Reactor Operator (SRO) license classes and industry and external training and development are two important programs to develop our employees and build a leadership pipeline. We address each program below.

Senior Reactor Operator License Class

Senior Reactor Operator (SRO) licenses are valued as both a technical and leadership development strategy. Obtaining an NRC SRO license requires an Initial License Training class, which provides the extensive training needed to prepare employees to become an NRC-licensed SRO and supervise the controls of a nuclear power reactor. Approximately 50 percent of those who enter the Initial License Training class are internal to the Company, which builds and advanced our leadership pipeline. We select internal SRO candidates whom we have identified as employees who can advance through the control room supervisor position and, longer term, to other positions of management outside of operations. Through earning the license, employees gain direct line of sight to the reactor core and the grave responsibility that goes with running a nuclear power reactor. While a license is not required for all key leadership positions, it is expected that individuals with an SRO move through the organization as a benefit of their experience. Across both nuclear sites, we aim to have 76 active license holders.

Industry and External Training and Development INPO or NEI Rotation

Targeted for individuals to broaden and share experience, a rotation offers employees the opportunity to gain insight into best practices and the pursuit of excellence across the nuclear industry. Through an 18-month assignment, employees learn what excellence looks like and understand key processes. INPO also offers seminars on leadership development.

3. Conclusion

As we look to continue operations at our nuclear facilities into 2050 and beyond, a highly skilled workforce is imperative. We have the plans in place to ensure the plants are fully staffed with the skilled employees we need to operate the plants safely, reliably, and affordably into the coming decades.

B. Workforce Transition

1. Introduction

Minn. Stat. § 3.8851, subd. 4 requires the Company to submit to the Minnesota Public Utilities Commission updates periodically, with the resource plan filing, of the Worker Transition Plan (WTP) required under Minn. Stat. § 116C.772, subd. 3. The WTP is required to address the event of a shutdown of PINGP for longer than six months.

The 1995 WTP (the original filing of this plan) reported that the conditions that could lead to a short lead-time reactive worker transition due to an unplanned immediate shutdown were not typical of the scenario facing Minnesota. Minnesota's nuclear generating plants have a long history of being well-maintained resulting in safe, reliable, and economic operations. The WTP described in 1995 assumed a long lead-time, proactive approach. MNGP and PINGP continue to have strong operating records and are expected to operate until at least 2040 and 2033/2034, respectively; our Preferred Plan includes a 20-year extension of both PINGP units to 2053/2054 and an additional 10-year extension of MNGP to 2050. This update continues to assume the long lead-time proactive approach to a WTP.

2. *Transition Plan Philosophy*

We anticipate that MNGP will operate at least until 2040, and as part of our Preferred Plan, we are proposing an additional 10-year life extension that would continue plant operations until 2050. Also as part of our Preferred Plan, we are proposing to extend PINGP by 20 years, to 2053 and 2054 for Units 1 and 2, respectively. These extended operating periods and Xcel Energy's commitment to employees affords the opportunity to plan for employee transition resulting from a planned plant closure. Xcel Energy will continue to base staffing decisions on operational excellence and NRC requirements that may result in changed staff assignments and levels.

Our nuclear generating plants are operated by dedicated nuclear professionals, as discussed above. The extended plant licenses, the fact that many workers will reach retirement age well before the extended licenses will expire, and a strong management commitment are critical to the success of the Xcel Energy Worker Transition Plan. This strategy provides employees the opportunity to develop their skills, so they are congruent with the changing needs of the company and the marketplace.

The proactive approach to managing human resources produces a workforce that is motivated, cross-functional, and flexible. This approach greatly reduces the need for reactive planning.

Should PINGP or MNGP close, there are four transition paths available. They are:

1. Stay with Xcel Energy in a similar job/career path.
2. Stay with Xcel Energy in a different job/career path.
3. Retire.
4. Leave Xcel Energy for outside employment opportunities.

The proactive strategy for managing human resources allows employees to prepare for each path, and thus position themselves for a number of potential outcomes. The Company acknowledges that a proactive transition requires prior planning, total management support, complete understanding and support throughout all levels of the corporation and a comprehensive guiding process.

Xcel Energy values its employees and recognizes that they make the nuclear operations excellent, and we have an obligation to help employees plan for the future. The result of effective planning is a partnership that yields strong nuclear operations and satisfied employees. Approximately 1,100 MNGP, PINGP, and nuclear corporate permanent employees and skilled positions would be eliminated or restructured should either of the plants close. Providing these employees with avenues to enhance their skills prior to plant closing will make the transition to new jobs (inside or outside of Xcel Energy) easier, but not painless. Xcel Energy's objective is to structure and develop its work force to meet the challenges inherent in a competitive business environment. That objective will be accomplished by:

1. Establishing Business Plan workforce effectiveness goals.
2. Translating those goals into an effective Human Asset Plan.
3. Producing employee development plans.

3. Xcel Energy Transition Processes

The transition processes described below apply to both non-bargaining and bargaining unit employees at MNGP and PINGP. For bargaining unit employees, the transition plan is in accordance with the collective bargaining agreement and Xcel Energy programs and processes as described below.

4. Internal Placement

a. Job Opportunity Bulletin

Xcel Energy provides online notification of employment and career development opportunities in all new or replacement positions. This process, in accordance with our collective bargaining agreement, is used prior to outside hiring.

b. Leadership Essentials

Xcel Energy has a program to identify employees interested in becoming a member of the Xcel Energy management team and provides assessment and development to them.

Leadership Essentials is an on-line resource designed to help both beginning and experienced leaders learn and continue to develop various leadership skills. All union employees are invited to participate.

c. Corporate Training Programs

Xcel Energy offers employees training and development courses for skills needed to stay current in their present job and development courses to prepare them for future positions. This training covers technical, computer and business skills.

d. Apprenticeship Training Programs

An apprentice is a person engaged in training for one of the skill areas covered in the current labor agreement. Programs are State of Minnesota registered and provide on-the-job training and related instruction in all areas of the apprenticeship being served.

e. Tuition Reimbursement

The Tuition Reimbursement Program gives employees financial assistance to take courses offered by accredited schools and institutions of higher learning to complete a degree program.

f. Severance

i. The severance pay agreement for bargaining unit employees is covered in the current labor agreements with IBEW locals 160 and 949.
ii. The Company has a severance plan for non-bargaining employees which covers regular, full-time or part-time employees of the Company not covered by a current labor agreement. To be eligible for severance, certain eligibility requirements must be met.

5. Summary

The foundation for this type of worker transition program is based on the availability of long-term planning. If a premature closure of either plant were to occur, the results would be less favorable. In that case, employees would be afforded less time to prepare themselves for other employment within Xcel Energy or for careers outside of the company. No amount of prior planning can alleviate employees' personal hardships should a valuable and efficient plant be forced to close prematurely. Such an occurrence would be highly speculative, and it would not be cost-effective to prepare contingencies based on scenarios that are not likely to occur.

6. *Conclusions*

1. Xcel Energy is committed to its employees. That commitment is reflected in the scope of resources available to employees. Xcel Energy will continue to invest heavily in employees' training and development so that the transition to a business environment will be proactive.
2. Xcel Energy's commitment to excellence in operations is unequivocal, as is the Company's commitment to operate MNGP and PINGP Units 1 and 2.
3. The long lead-time prior to potential plant closings affords Xcel Energy and its employees an opportunity to plan for the transition.
4. An orderly transition is possible through Business and Human Asset Planning as performed by Xcel Energy.

7. *Commitments*

1. Xcel Energy will continue to account for changes in the workforce through business planning and Human Asset Planning.
2. Xcel Energy will continue to work with affected unions to promote the retention and training of its highly skilled and dedicated workforce.

VI. CYBER SECURITY

Order Point 23.D of the Commission's IRP Order requires the Company to explain, "[c]yber-security issues or concerns as plants move from analog to digital systems."

The current NRC-regulated cyber security program is well established across the nuclear industry, subject to a regular inspection cycle like the many other regulated programs at the plants. The program requires a high degree of management oversight and is highly effective in maintaining plant and public safety as related to potential cyber vulnerabilities associated with digital plant systems and equipment. Digital equipment that has the potential to impact reactor power is isolated from business networks and has significant additional controls in place to meet program requirements. These additional controls are specific to the requested equipment and its function and may include data access controls (e.g., user restrictions and password requirements); impact and risk analysis; and disaster recovery and contingency planning.

Concerns around digital systems are primarily related to maintenance costs rather than security or safety. In the context of nuclear generation, digital systems have proven highly reliable and effective when kept current. Still, their life cycle is generally shorter than the legacy analog systems they replace, and they are expensive to stay current under existing budgets and engineering processes. It is common for digital plant systems to become obsolete before upgrades can be engineered and installed, which makes maintenance problematic and expensive should failures occur.

Therefore, considering the designs of the Xcel Energy nuclear fleet, ongoing plant upgrades from analog to digital will take place discreetly, replacing specific equipment or systems to generally maintain the historical plant design as opposed to integrating many systems under common digital platforms, as would be expected in more modern plant designs. The existing NRC regulatory framework supports long-established engineering processes, to which cyber processes are linked.

VII. ADDITIONAL SPENT NUCLEAR FUEL

Order Point 23.F of the Commission's IRP Order requires the Company to explain "[a]dditional spent nuclear fuel generated over a 10- or 20-year period."

We anticipate that MNGP will discharge 800 spent fuel assemblies through 2040, or 1,600 spent fuel assemblies through 2050 if the plant is extended beyond the 10-year life extension currently approved by the Commission. At PINGP, we anticipate that continued operation over a 20-year period between 2033/2034 to 2053/2054, if approved, would result in 1,200 fuel assemblies being discharged.

VIII. TRANSPORTING STORED FUEL

Order Point 23.G of the Commission's IRP Order requires the Company to explain "[h]ow fuel stored on-site will be removed during the next integrated resource plan period."

This section examines opportunity for dry fuel storage at both MNGP and PINGP to be transported and stored off-site at a consolidated interim storage facility (CISF) or through the U.S. Department of Energy's (DOE's) Consent-Based Siting process. Two privately owned CISF designs have NRC license approvals but are delayed in the court system. While Yucca Mountain remains an unviable solution, the DOE's Consent-

Based Siting process is intended to further educate and provide transparency to potential future host communities.

A. Consolidated Interim Storage Facilities

1. *Interim Storage Partners (ISP) Storage Facility*

A consolidated interim storage project was initiated by Waste Control Specialists (WCS) for a site in Andrews County, Texas, adjacent to WCS's existing low-level radioactive waste and hazardous waste storage and disposal facilities. The NRC license application for this project was filed in April 2016. In April 2017, WCS asked the NRC to suspend the review of this application. Subsequently, WCS and Orano USA (formerly Areva Nuclear Materials) formed a joint venture to license the facility. In response to letters to the NRC in June and July 2018 from the joint venture, Interim Storage Partners (ISP), the NRC restarted its review of the application. A number of environmental and other organizations sought to intervene in the NRC proceeding and two organizations moved the NRC to reject the application (and the Holtec application described below), alleging that the NRC lacked the jurisdiction to consider the application. The NRC denied those latter requests and one of the organizations appealed the NRC's denial to the D.C. Circuit in December 2018.

On the NRC's motion, the Court dismissed the case in June 2019, as not ripe for judicial review. In August 2019, the Atomic Safety and Licensing Board considered the hearing requests, admitted one contention submitted by one of the petitioners, and dismissed the remaining contentions and petitioners. A subsequent Licensing Board decision dismissed the remaining contention as moot and rejected an attempt to amend. The Board also dismissed another petitioner's late-filed contention. Appeals from the Board decisions, as well as a motion to reopen the proceeding, were denied by the NRC. The NRC also rejected a late-filed contention not previously ruled on by the Board. Appeals of the NRC decisions to the D.C. Circuit were held in abeyance by the Court pending completion of the NRC proceeding. The NRC issued a license to ISP for their proposed commercial consolidated interim storage facility on September 13, 2021, but on August 25, 2023, the 5th Circuit Court of Appeals issued a ruling stating that the NRC lacks the authority to issue licenses for private, away-from-the-reactor spent fuel storage facilities.

On October 24, 2023, the NRC and ISP filed a rehearing petition before the entire Fifth Circuit, which includes 19 judges. NEI and Holtec submitted friend of the court briefs in support of the rehearing petition. Texas and the other challenger, Fasken, both filed responses in December 2023. A rehearing is awaiting court approval.

2. Holtec HI-STORE Consolidated Interim Storage Facility

Holtec International has proposed the HI-STORE Consolidated Interim Storage Facility for a site in Eddy and Lea Counties in southeastern New Mexico. Holtec filed an application with the NRC for this facility in March 2017. In response to NRC's July 2018 notice of opportunity for hearing, a number of environmental and other organizations filed petitions to intervene in the NRC proceeding. At about the same time, two organizations moved the NRC to reject the application (and the ISP application described above) alleging that the NRC lacked the jurisdiction to consider the application. After the NRC denied those requests, one of the organizations filed an appeal with the U.S. Court of Appeals for the D.C. Circuit in December 2018. On the NRC's motion, the Court dismissed the case in June 2019 as not ripe for judicial review. In May 2019, the Atomic Safety and Licensing Board issued a Memorandum and Order rejecting all the petitions to intervene filed in response to the July 2018 opportunity for hearing. Five of the six petitioners filed appeals with the NRC challenging the Licensing Board's rejection of their petitions. In April 2020, the NRC rejected all the appeals except for remanding to the Licensing Board four contentions put forward by one of the petitioners. In June and September 2020 orders, the Board denied the admission of the remanded contentions and other late-filed contentions—as well as motions to reopen the proceeding. Additionally, in June 2020, April 2021, and June 2021, four of the petitioners who were denied admission in the NRC proceeding filed appeals before the U.S. Court of Appeals for the D.C. Circuit. The Court consolidated these appeals and was holding them in abeyance pending the completion of the NRC proceedings. The NRC issued a license to Holtec on May 9, 2023, authorizing the company to receive, possess, transfer and store 500 canisters holding approximately 8,860 metric tons of commercial spent nuclear fuel for 40 years. In March 2023, New Mexico approved legislation aimed at stopping the project.

The concern by members of the New Mexico Senate Energy and Natural Resources Committee, including Senator Martin Heinrich, is that this will not be interim storage as what it is referred to by the NRC and Holtec, but rather permanent storage unless a permanent repository is legislatively approved and constructed by the DOE.

3. Conclusion

While we believe the centralized storage facilities proposed by ISP and Holtec meet all NRC regulatory requirements and would be a positive development in the management of spent nuclear fuel, we do not consider it a viable alternative to the MNGP or PINGP ISFSIs at this time due to legislative challenges.

Each consolidated interim storage facility will need to work with their respective states on permitting issues and will develop a business model for operations prior to construction. In addition, DOE has begun its own process to find a consent-based interim storage location over the next several years (as described below) and it is unclear how this will impact the two private facilities currently in licensing.

If either of these facilities become operational in the future, or should another solution become available through the DOE Consent-Based Siting Program, we would explore the possibility of shipping fuel to that site. It is unclear if this could be accomplished within the 2024-2040 IRP timeline.

B. Yucca Mountain and DOE Consent-Based Siting Program

The application to license the Yucca Mountain permanent repository remains pending before the NRC, following the unsuccessful attempt by the Obama Administration to terminate the proceeding and withdraw the application. The NRC Staff's technical and environmental reviews have been essentially completed, but the adjudicatory hearings on the application before NRC Atomic Safety and Licensing Board remain suspended—with numerous contentions submitted by Nevada and other opponents remaining to be resolved before the NRC can license the project. The Biden Administration did not seek any funding for Yucca Mountain in the FY2021 or FY2022 budgets. North Las Vegas KLAS News reported that during Senate committee hearings in June 2021, Secretary of Energy Jennifer Granholm testified that the Administration does not support Yucca Mountain as a solution for nuclear waste disposal but will begin a consent-based siting process in 2021.

In June 2023, DOE awarded 13 contracts to consortiums consisting of university, non-profit, and private-sector partners that will work with communities interested in learning more about nuclear energy and spent nuclear fuel storage with a goal of education and transparency. Communities will participate by working with DOE and these consortiums through a phased approach to determine whether and how being a host community could align to their goals. The three phases to this approach include: (1) planning and capacity building, (2) site screening and assessment, and (3) negotiation and implementation.

Xcel Energy is part of a consortium with the Prairie Island Indian Community and several others led by the Southwest Research Institute (SwRI) that was awarded a DOE contract. The consortium will collaborate with a couple of selected communities to educate and provide transparency with the intent to enter into the phased approach described above.

The DOE's Consent-Based Siting Program is in its initial stages. As an unpaid award winner for the program contract, the Company will remain actively engaged with key stakeholders throughout the entire process. Once a community has accepted a host community role, the community and DOE will need to work with respective states on permitting issues and will develop a business model for operations prior to construction. It is unclear how much can be accomplished within the 2024-2040 IRP timeline.

IX. FUTURE PLANS AND ADDITIONAL STATE AND FEDERAL PROCESSES

Order Point 23.H of the Commission's IRP Order requires the Company to explain "[w]hich additional state permits, Certificates of Need, or federal licenses will be required."

Extended plant operations beyond the existing operating license expiration date requires federal approval by the NRC. In this case, both MNGP and PINGP have already extended their operating licenses once through the License Renewal (LR) application process. The second extension is referred to as Subsequent License Renewal (SLR). The Company submitted an SLR application for MNGP on January 9, 2023, and anticipates a decision from the NRC by end of year 2024 and license issuance in 2025. PINGP has just begun development of the application and anticipates submittal before the end of 2026. The federal SLR process is for a 20-year extension.

Also required to extend plant operations beyond the existing operating license is approval from the Commission to expand spent nuclear fuel storage on site in ISFSI. For MNGP, the Company requested approval by the Commission for a 10-year ISFSI expansion through the Certificate of Need process (Minn. Stat. §116B.77- 166B.83), in alignment with the Preferred Plan from our 2019 IRP. The Commission granted the Certificate of Need, which is subject to state legislative action this coming session, with its October 17, 2023, Order.[15] For MNGP, we would seek another Certificate of Need to support the additional 10-year life extension put forth in our Preferred Plan and would likely begin that process shortly after a Commission decision on this Resource Plan.

For PINGP, the Company is filing a Certificate of Need application in the near future in MNPUC Docket No. E002/CN-24-68 for a PINGP 20-year Independent Spent Fuel Storage Installations (ISFSI) expansion in support of SLR, which would expand PINGP's operating license from 2033/2034 to 2053/2054, in alignment with our Preferred Plan.

[15] Docket No. E002/CN-21-668.

Table M-4 lists additional state and federal licenses, permits, and certificates required for an additional 10-year extension of MNGP (to 2050), and a 20-year extension of PINGP's units (to 2053 and 2054). We note that this list encompasses known requirements as this time, but it should be considered preliminary and subject to change.

Table M-4: State and Federal Requirements for Continued MNGP and PINGP Operation

Agency	Authority	Requirement And Plant	Authorized Activity
NRC	Atomic Energy Act [10 CFR Part 50]	MNGP operating license PINGP operating licenses (Unit 1 and Unit 2)	Subsequent License Renewal of +20 years. MNGP SLR currently in review with NRC. PINGP Unit 1 and Unit 2 SLR submittal anticipated in 2026.
MN PUC	Minn. Stat. §216B.243- CERTIFICATE OF NEED FOR LARGE ENERGY FACILITY Minnesota Rule Chapter 7855 – CERTIFICATE OF NEED, LARGE ENERGY FACILITY Minn. Stat. §116B.77-166B.83 – RADIOACTIVE WASTE MANAGEMENT FACILITY ATHORIZATION	MNGP and PINGP Certificate of Need to extend onsite storage of spent fuel	Continued operation of MNGP and PINGP Independent Spent Fuel Storage Installations (ISFSIs)
MPCA	Clean Water Act Section 401 [33 USC 1341]	Certification of water quality standards for both MNGP and PINGP.	Section 401 Water Quality Certification issued by the state for operation of MNGP and PINGP.
USACE	Clean Water Act Section 404 [33 USC 1344]	Regional general permit (Section 404) for both MNGP and PINGP	Maintenance dredging in front of the intake apron on the Mississippi River.
Alliance for Uniform Hazmat Transportation Procedures	49 USC 5119	Uniform Program Credentials (Hazmat permit and registration) MNGP and PINGP	Hazardous material shipment.

Agency	Authority	Requirement And Plant	Authorized Activity
Tennessee Department of Environment and Conservation (TDEC)	TDEC Rule 0400-20-10-.32	License to ship radioactive material MNGP and PINGP	Shipment of radioactive material to a licensed disposal/processing facility in Tennessee.
Utah Department of Environmental Quality (UDEQ)	Utah Administrative Code R313-26	General site access permit for radioactive waste disposal MNGP and PINGP	Delivery of radioactive waste to a land disposal facility located in Utah.
MPCA	Minnesota Rules Part 7045.0225	Hazardous waste generator license MNGP and PINGP	Authorizes facility to operate as a hazardous waste generator.
MPCA	Minnesota Statutes Chapters 115 and 116	NPDES permit MNGP and PINGP	Discharges of wastewater to waters of the state.
MPCA	Minnesota Rules Part 7007.0150	Air emission permit MNGP and PINGP	Operate air emission facility (four diesel generators, diesel fire pump, three flexible pumps, and heating boiler).
MPCA	Minnesota Rules Chapter 7150	Tank registration MNGP and PINGP	Underground storage tank registration.
MPCA	Minnesota Rules Chapter 7151	Tank registration MNGP and PINGP	Aboveground storage tank registration.
MDNR	Minnesota Statutes Chapter 103G	State dredging permit MNGP and PINGP	Maintenance dredging of sand and silt from discharge canal and intake skimmer area.
MDNR	Minnesota Statutes Chapter 103G.271	Water appropriations permit MNGP and PINGP	Groundwater withdrawals from Well #1 and Well #2.
MDNR	Minnesota Statutes Chapter 103G.272	Water appropriations permit MNGP and PINGP	Surface water withdrawals from the Mississippi River.
MDNR	Minnesota Statutes Section 97A.401	Division of Fish and Wildlife special permit MNGP and PINGP	Collection of fish for scientific purposes.

Agency	Authority	Requirement And Plant	Authorized Activity
MDNR	Minnesota Statutes Section 84D.11	Division of Ecological and Water Resources permit MNGP and PINGP	Transport of zebra mussels and other prohibited invasive species to Xcel Energy facilities or to a repair site for purposes of control, disposal, and maintenance of equipment.
City of Monticello	City of Monticello Ordinance Title V, Chapter 52	Sanitary Sewer Wastewater Discharge Agreement MNGP only	Agreement to discharge domestic sanitary waste to the City of Monticello sanitary sewer collection system.

X. CONCLUSION

Xcel Energy's nuclear fleet has provided carbon-free electricity to our Upper Midwest customers safely and reliably for decades. The continued operation of PINGP and MNGP is crucial to achieving the Company's—and our states'—policy objectives, while keeping bills low and maintaining a reliable, resilient system. We have robust plans in place to ensure operational excellence, continue our efforts to ensure spent fuel can be transported offsite, manage costs, and maintain a skilled workforce that will operate the plants over the coming decades as we continue to reduce carbon emissions.

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Nuclear Leave Behind Study Report

Performed by:
Craig Wrisley
Jessica Kiddoo
Matthew Kukacka

Transmission Planning
13 Nov, 2023

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Certification

I hereby certify that this report was prepared
by me or under my direct supervision and that
I am a duly Licensed Professional Engineer under the
Laws of the state of Minnesota

Craig Wrisley
11/13/2023
License# 54948

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Executive Summary

This analysis was performed to determine the steady state impacts and dynamic resources needed online as a result of retiring the Monticello Nuclear Generating Plant, Prairie Island Nuclear Generating Plant, and both the Monticello and Prairie Island Nuclear Generating Plants. Integrated System Planning (ISP) Transmission Planning engineers performed a study to evaluate the transmission system with the nuclear generation station retirements along with the planned Sherco coal generation replacement with Minnesota Energy Connection (MNEC) renewable generation and the AS King coal generation replacement with King Transmission Connection solar generation. Existing natural gas resources were turned on to replace the generation shortfalls based on the MISO dispatch of renewables in the model. This study is a reliability only look – system transfer capability and resource capacity analyses are out of the work scope of this study.

This study looks at the retirement of the nuclear generating stations without replacement of generation rights. The following Table M1-1 shows the retirement scenarios analyzed.

Table M1-1
Nuclear Generation Retired

Scenario Analyzed	Monticello Generation Retired (MW)	Prairie Island Generation Retired (MW)	Total Generation Retired (MW)
Monticello Retire	637	0	637
Prairie Island Retire	0	1150	1150
Monticello and Prairie Island Retire	637	1150	1778

The steady state analysis identified the retirement of the nuclear generation plants without replacement generation resulted in thermal overloads and voltage violations requiring system upgrades.

Based on the dynamic analysis results performed in this study, significant replacement generation is needed:

- Summer Peak Load Case, in addition to generation on in the base model, required all available gas generation on at Anson, Inver Grove, and Blue Lake (total 521 MW) as well as load reduction in the Twin Cities area.
    - Monticello Retire – 10% (537.37 MW)
    - Prairie Island Retire – 20% (1074.74 MW)
    - Monticello and Prairie Island Retire – 30% (1612.11 MW)
- Shoulder Load Average Wind Case, in addition to the generation on in the base model required additional combustion generation turned on.
    - Monticello Retire – High Bridge 7 and 9 (388MW), Riverside 7 and 9 (318 MW). Total generation addition of 706 MW.
    - Prairie Island Retire - High Bridge 7 and 9 (388MW), Riverside 7, 9, and 10 (476 MW), Blue Lake 7 and 8 (302 MW). Total generation addition of 1,166 MW.

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- Monticello and Prairie Island Retire – High Bridge 7, 8, and 9 (550 MW), Riverside 7, 9, and 10 (476 MW), Blue Lake 1-4, 7, and 8 (455MW), Inver Grove 1-6 (282 MW). Total generation addition of 1763 MW.

Scenarios Analyzed

2028 Summer Shoulder Average Wind, and Summer Peak scenarios are analyzed in this study. Renewables in the NSP system are modeled at seasonal generation levels; Solar at 50% for Summer Peak, 31% for Summer Shoulder Average Wind, Wind at 15.5% for Summer Peak, 27% for Summer Shoulder Average Wind.

NSP load information is shown in following Table M1-2.

Table M1-2
NSP Load Level

Year	Season	Load Level
2028	Summer Shoulder Average Wind	6,383 MW
2028	Summer Peak	9,064 MW

Steady State Simulation Results

Steady state analysis was performed on the base case, Monticello retire case, Prairie Island retire case, and both Monticello and Prairie Island retire case for both the Summer Peak and Summer Shoulder Average Wind case. Available NSP natural gas generation was turned on to reduce the number of unsolved contingencies. The number of unique facilities with new or increased >0.5% voltage violations and thermal violations beyond the preexisting violations in the base case and associated costs to mitigate them for each case are listed in Table M1-3.

Table M1-3
Voltage and Thermal Upgrades with cost for Steady State Violations

Transient Stability Simulation Results

Transient stability analysis was performed on the base case, Monticello retire case, Prairie Island retire case, and both Monticello and Prairie Island retire case for both the Summer Peak and

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Summer Shoulder Average Wind case. Available NSP natural gas generation was turned on to achieve stable dynamic response. If no additional NSP natural gas resources were available, load in the Twin Cities area was scaled down to achieve stable dynamic response.

Table M1-4
Generation and Load Adjustments with cost for Stable Dynamic Response

	Summer Peak			Summer Shoulder		
Scenario Analyzed	**Additional Generation On (MW/$)**	**Load Reduction (MW/$)**	**Total Cost ($)**	**Additional Generation On (MW)**	**Load Reduction (MW)**	**Total Cost ($)**

Without Twin Cities Load reduction for the summer peak case, and additional gas generation turned on in both summer peak and shoulder average wind case, generator rotor angles exceed +/-300 degrees, which is indicative of the point where the generator would lose synchronization with the grid and trip offline. Example plots of Unstable and Stable Response are shown in Figure M1-1 and Figure M1-2.

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Figure M1-1
2028SHAW Unstable Generator Angle Response

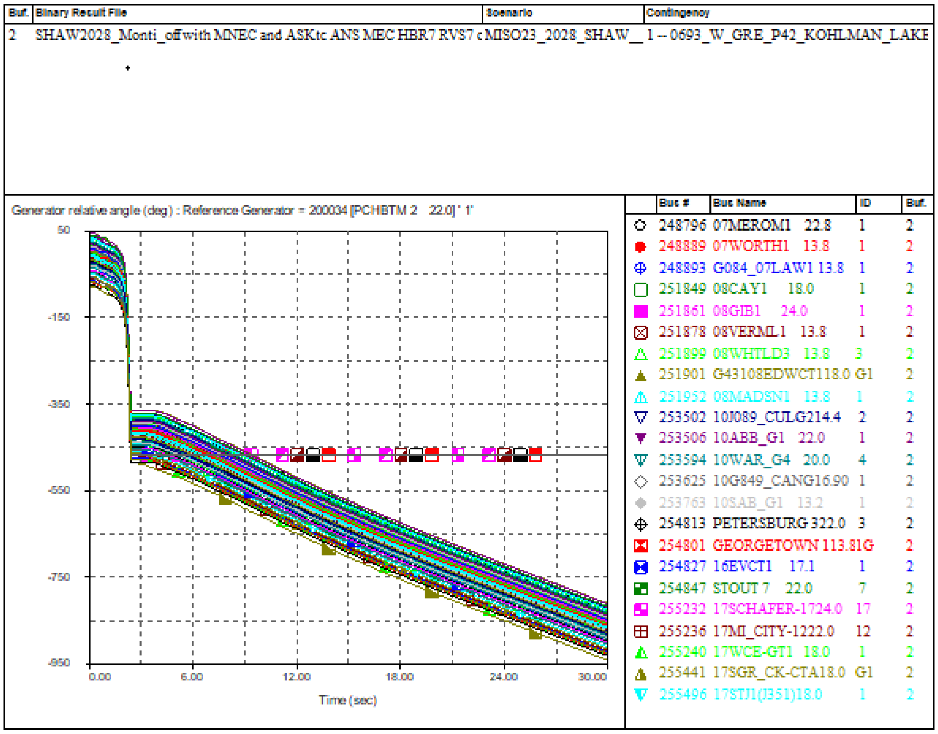

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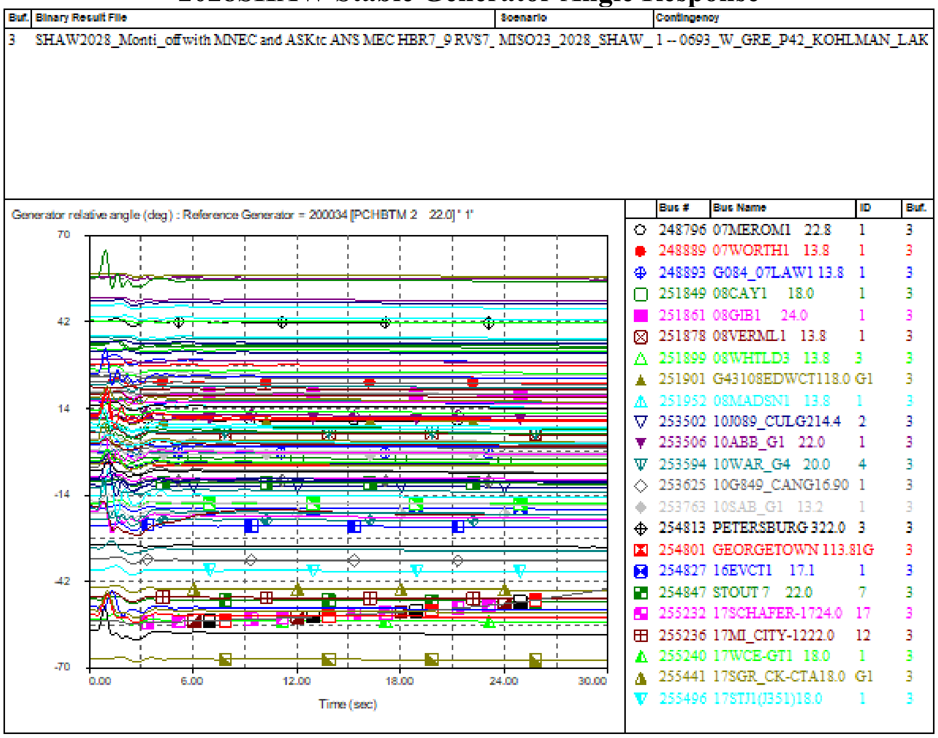
Figure M1-2
2028SHAW Stable Generator Angle Response



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Introduction

This analysis was performed to determine the steady state impacts and dynamic resources needed online as a result of separately retiring the Monticello Nuclear Generating Plant and the Prairie Island Nuclear Generating Plant. For further analysis, the retirements of both the Monticello and Prairie Island Nuclear Generating Plants simultaneously were included in the analysis. Additionally, Integrated System Planning (ISP) Transmission Planning engineers performed a study to evaluate the transmission system steady state with the nuclear generation station retirements along with the planned Sherco coal generation replacement with Minnesota Energy Connection (MNEC) renewable generation and the AS King coal generation replacement with King Transmission Connection solar generation. Existing natural gas resources were turned on to replace the generation shortfalls based on the MISO dispatch of renewables in the model. This study is a reliability only look – system transfer capability and resource capacity analyses are out of the work scope of this study.

Assumptions

This study is performed utilizing Siemens PSSE version 35.3.2 for steady state analysis and Powertech TSAT version 22.3.39 for dynamic analysis and based on the MISO Transmission Expansion Plan (MTEP) 2023 steady state models and dynamics package. MISO MTEP 2023 series, year 2028 models are selected as the starting models; no substantial load growth is assumed in this study. Sherco coal generation is replaced with Minnesota Energy Connection renewable generation at MISO renewable dispatch levels. AS King coal generation is replaced with King Transmission Connection solar generation at MISO solar dispatch levels.

Potential Limitations

Model

Sherco and King generation replacement locations and details are assumed based on the preliminary project scope, final project details may have minor differences.

Retirement of the nuclear generating stations were assumed to have no replacement generation installed. Load reduction where needed for stability was performed as a percent reduction across all loads in the Twin Cities area.

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1 Models and Assumptions

1.1.1 Models Utilized

Siemens PSSE version 35.3.2 for steady state analysis and Powertech TSAT version 22.3.39 for dynamic analysis and based on the MISO MTEP 2023 steady state models and dynamics package. MISO MTEP 2023 series, year 2028 models are selected as the starting models; no substantial load growth is assumed in this study.

1.1.2 Model Development

MTEP 2023, year 2028 Summer Peak (SUM) and 2028 Shoulder Average Wind (SHAW) models are selected as the starting models. Sherco coal generation is replaced with Minnesota Energy Connection renewable generation at MISO renewable dispatch levels. AS King coal generation is replaced with King Transmission Connection solar generation at MISO solar dispatch levels.

2028 Summer Shoulder Average Wind, and Summer Peak scenarios are analyzed in this study. Renewables in the NSP system are modeled at seasonal generation levels; Solar at 50% for Summer Peak and 31% for Summer Shoulder Average Wind; Wind at 15.5% for Summer Peak and 27% for Summer Shoulder Average Wind. NSP load information is shown in Table M1-5.

Table M1-5
NSP Load Level and Thermal Generation Level

Year	Season	Load Level
2028	Summer Shoulder Average Wind	6,383 MW
2028	Summer Peak	9,064 MW

1.1.3 Modeling Assumption

MTEP 2023, year 2028 Summer Peak (SUM) and 2028 Shoulder Average Wind (SHAW) models are selected as the starting models. Sherco coal generation is replaced with Minnesota Energy Connection renewable generation at MISO renewable dispatch levels. AS King coal generation is replaced with King Transmission Connection solar generation at MISO solar dispatch levels. Analysis is performed on cases with Monticello Nuclear Generating Plant retired, Prairie Island Nuclear Generating Plant retired, and both Monticello and Prairie Island Nuclear Generating Plants retired.

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2 Steady State Analysis

MISO MTEP 2023 Steady State 2033SUM and 2033SHAW models are used to conduct the steady state analysis. Steady analysis was performed on the base case, Monticello retire case, Prairie Island retire case, and both Monticello and Prairie Island retire case for both the Summer Peak and Summer Shoulder Average Wind case. Full N-1 and N-1-1 contingencies were run for LRZ 1.

Available NSP natural gas generation was turned on to reduce the number of unsolved contingencies. Robust solution in PSSE was used to allow for system adjustment of reactive devices and generation during contingency analysis to reduce the number of unsolved contingencies.

3 Stability Analysis

MISO MTEP 2023 Transient Dynamic package is used to conduct the transient stability analysis. Three phase faults with normal clearance time and single line to ground faults with a stuck breaker are tested for major 345 kV substations, transmission lines in Twin Cities and neighboring areas. Selected 345 kV bus voltages and transmission line power flow in Twin Cities and neighboring areas are monitored and plotted. The disturbances studied are listed in Table M1-6:

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Table M1-6
Disturbances Simulated in the Study

Name	Description
0693 redacted	
0857 redacted	
0860 redacted	
0865 redacted	
0866 redacted	
0867 redacted	
0868 redacted	
0879 redacted	
0890 redacted	
0891 redacted	
0892 redacted	
0893 redacted	
0896 redacted	
0898 redacted	
0920 redacted	
0922 redacted	
0927	

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Name	Description
0935 redacted	
0936 redacted	
0941 redacted	
0942 redacted	
0943 redacted	
0944 redacted	
0945 redacted	
2199 redacted	
2218 redacted	
2219 redacted	
2229 redacted	
2238 redacted	
2242 redacted	
2257 redacted	
2277 redacted	

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Available natural gas generation was turned on iteratively to achieve stability. Where insufficient natural gas generation was available to achieve stability, scalable load in the Twin Cities was reduced by a percentage of area load until stability was achieved.

- Summer Peak Load Case, in addition to generation on in the base model, required all available generation on at Anson, Inver Grove, and Blue Lake (total 521 MW) as well as load reduction in the Twin Cities area.
  - Monticello Retire – 10% (537.37 MW)
  - Prairie Island Retire – 20% (1,074.74 MW)
  - Monticello and Prairie Island Retire – 30% (1,612.11 MW)
- Shoulder Load Average Wind Case, in addition to the generation on in the base model required additional combustion generation turned on.
  - Monticello Retire – High Bridge 7 and 9 (388 MW), River Side 7 and 9 (318 MW). Total generation addition of 706 MW.
  - Prairie Island Retire - High Bridge 7 and 9 (388 MW), River Side 7, 9, and 10 (476 MW), Blue Lake 7 and 8 (302 MW). Total generation addition of 1,166 MW.
  - Monticello and Prairie Island Retire – High Bridge 7, 8, and 9 (550 MW), Riverside 7, 9, and 10 (476 MW), Blue Lake 1-4, 7, and 8 (455 MW), Inver Grove 1-6 (282 MW). Total generation addition of 1,763 MW.

4 Analysis Results

In the steady state analysis, available NSP natural gas generation was turned on to reduce the number of unsolved contingencies. The number of unique facilities with new or increased >0.5% voltage violations and thermal violations beyond preexisting violations in the base case were

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identified. Associated costs assigned based on MISO Transmission Cost Estimation Guide For MTEP23[1] for rebuild of overloaded lines to larger conductor size and assuming 5 150MVAR statcoms, situated in the vicinity of the retired nuclear units would resolve the voltage violations observed. The cost breakdown of the associated upgrades is listed in Table M1-7:

Table M1-7
Voltage and Thermal Upgrades with cost for Steady State Violations

In the dynamic analysis, available NSP natural gas generation was iteratively turned on to achieve stability. Once all available NSP natural gas was turned on, Twin Cities load was scaled down to achieve stability. Generation additions and load reduction are summarized in Table M1-8:

Table M1-8
Generation and Load Adjustments for Stable Dynamic Response

	Summer Peak		Summer Shoulder	
Scenario Analyzed	**Additional Generation On (MW)**	**Load Reduction (MW)**	**Additional Generation On (MW)**	**Load Reduction (MW)**
Monticello Retire	**512**	**537.37**	**706**	**0**
Prairie Island Retire	**512**	**1074.74**	**1,166**	**0**
Monticello and Prairie Island Retire	**512**	**1612.11**	**1,763**	**0**

[1] MISO Transmission Cost Estimation Guide for MTEP23337433.pdf (misoenergy.org)

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5 Analysis Results Discussion

For the steady state results, any line with thermal violations is assumed to need an upgrade. Transformers with thermal violations are assumed to be replaced with transformer sized to carry the contingency level flows. Voltage violations are assumed to need reactive support in the form of capacitors or reactors. MISO cost estimation values are used to determine the estimated cost of upgrades as summarized in Table M1-9.

Table M1-9
Steady State Upgrade Summary

	Summer Peak			**Summer Shoulder**		
	Line Upgrade (miles/cost $)	**Reactive Support (MVAR/cost $)**	**Total Cost ($)**	**Line Upgrade (miles/cost $)**	**Reactive Support (MVAR/cost $)**	**Total Cost ($)**
Monticello Retire						
Prairie Island Retire						
Monticello and Prairie Island Retire						

For the dynamic results, cost was applied to the natural gas units turned on to maintain system stability assuming gas price of [redacted]. Cost was also applied to load reduction to maintain system stability in the Summer Peak load case. Costs associated with dynamic stability are summarized in Table M1-10.

Table M1-10
Dynamic Generation and Load Adjustments Costs

	Summer Peak			**Summer Shoulder**		
Scenario Analyzed	**Additional Generation On (MW/$)**	**Load Reduction (MW/$)**	**Total Cost ($)**	**Additional Generation On (MW)**	**Load Reduction (MW)**	**Total Cost ($)**
Monticello Retire						
Prairie Island Retire						
Monticello and Prairie Island Retire						

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2028 Summer Peak Case:

Generator angular stability issues were identified at generation and load reduction levels below those indicated in Table 6 as indicated by generator angles exceeding +/- 300 degrees, which reflects the angle at which the generator would lose synchronization with the electric grid and trip offline. Indicative plot of angular instability is shown in Figure M1-3. Stable generator angle plot examples for each retirement scenario are shown in Figure M1-4, Figure M1-5, and Figure M1-6.

Figure M1-3
SUM28 Prairie Island and Monticello Retirement Angular Instability

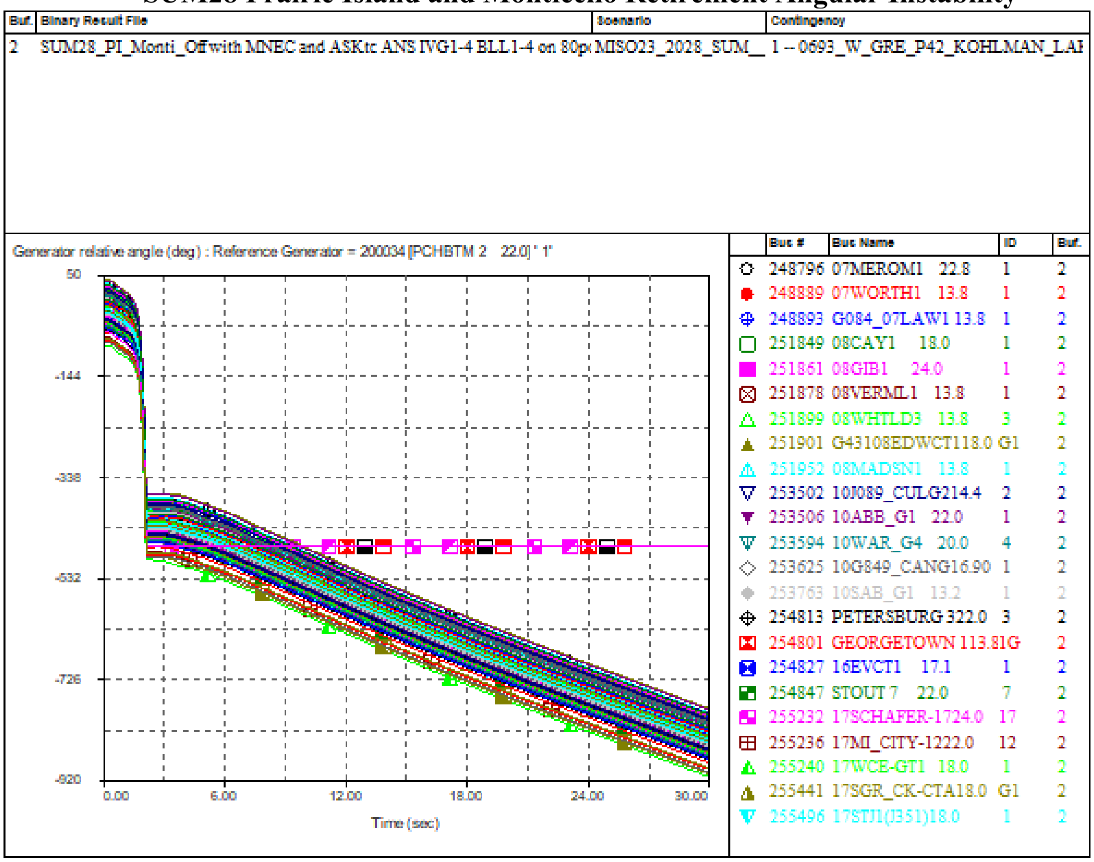

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Figure M1-4
SUM28 Monticello Retirement Angular Stability

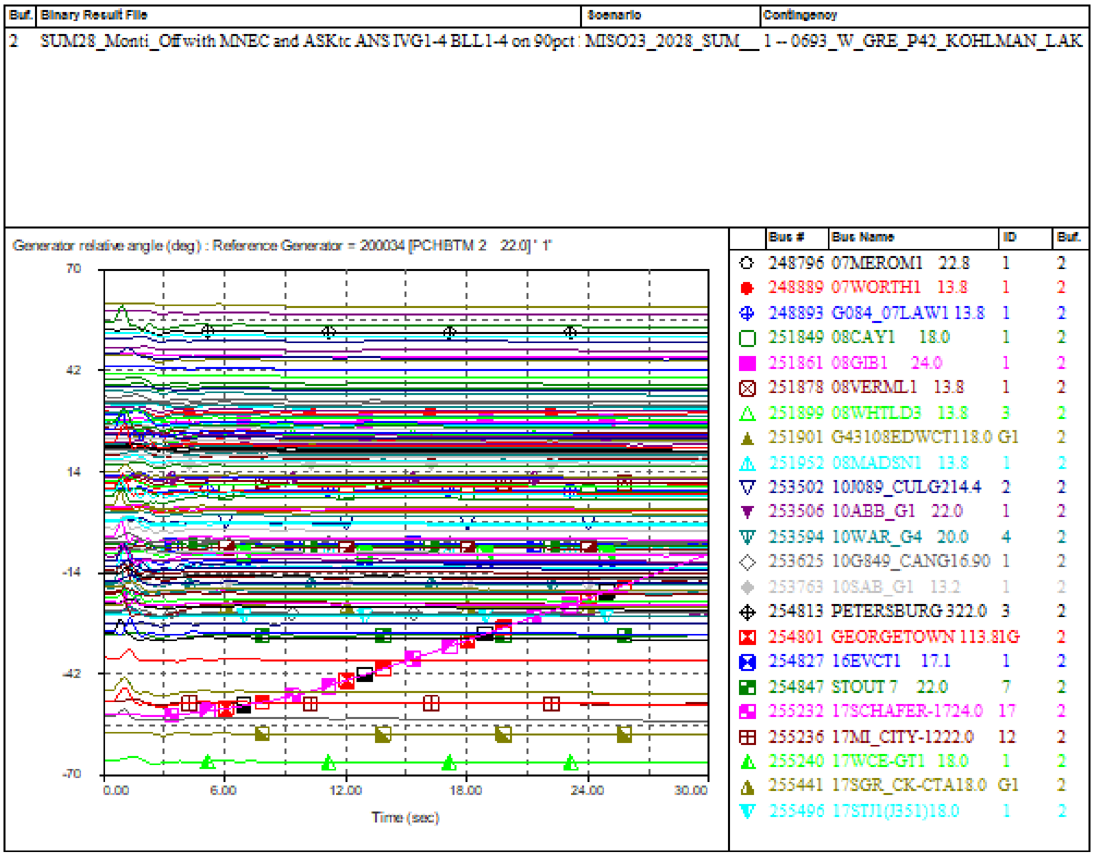

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Figure M1-5
SUM28 Prairie Island Retirement Angular Stability

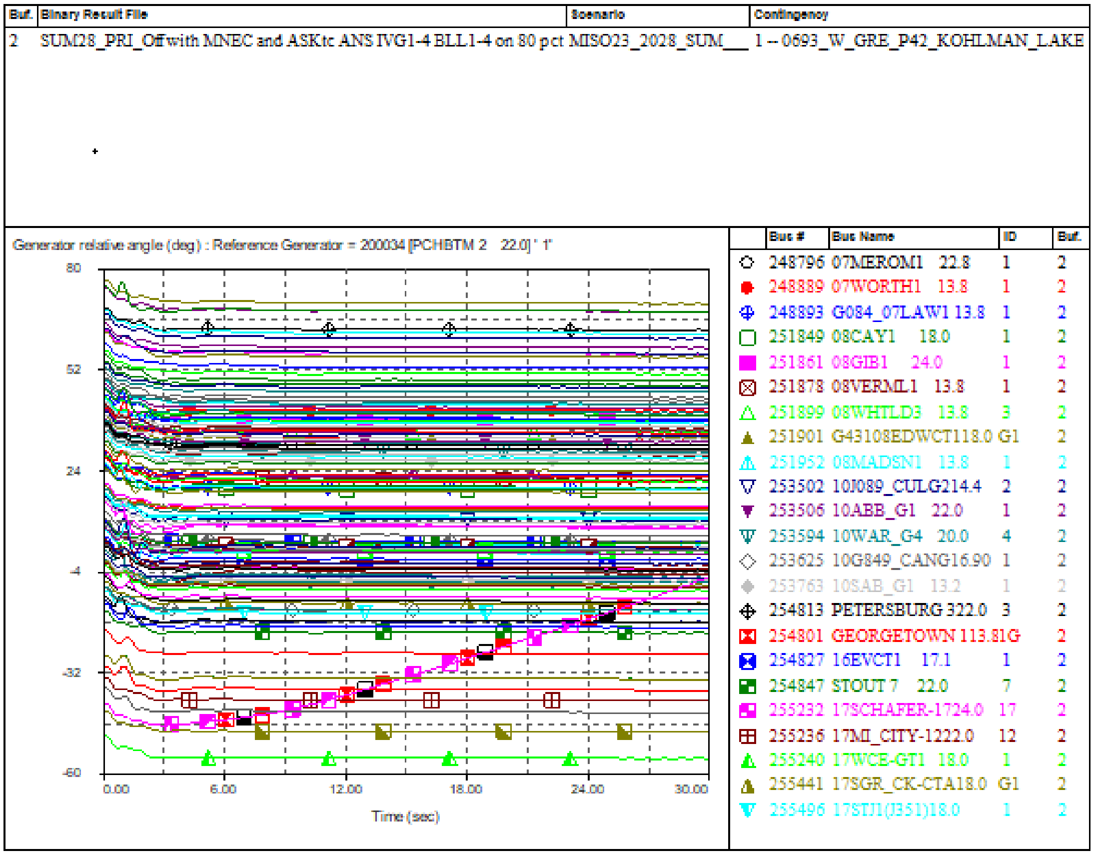

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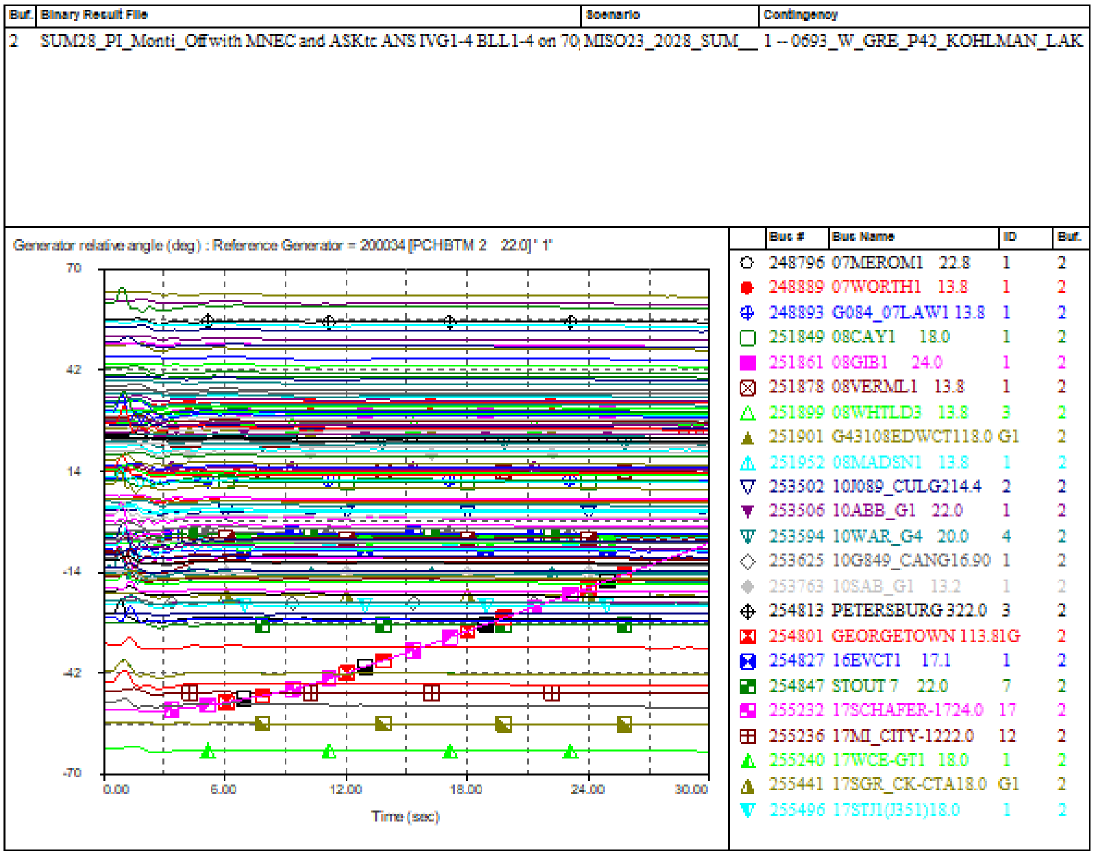
Figure M1-6
SUM28 Prairie Island and Monticello Retirement Angular Stability



Bus Voltage and Frequency were also montiored with no identified instability.

2028 Summer Shoulder Average Wind Case:

Generator angular stability issues were identified at generation levels below those indicated in Table 6 as indicated by generator angles exceeding +/- 300 degrees, which reflects the angle at which the generator would lose synchronization with the electric grid and trip offline. Indicative plot of angular instability is shown in Figure M1-7. Stable generator angle plot examples for each retirement scenario are shown in Figure M1-8, Figure M1-9, and Figure M1-10.

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Figure M1-7
SHAW28 Prairie Island and Monticello Retirement Angular Instability

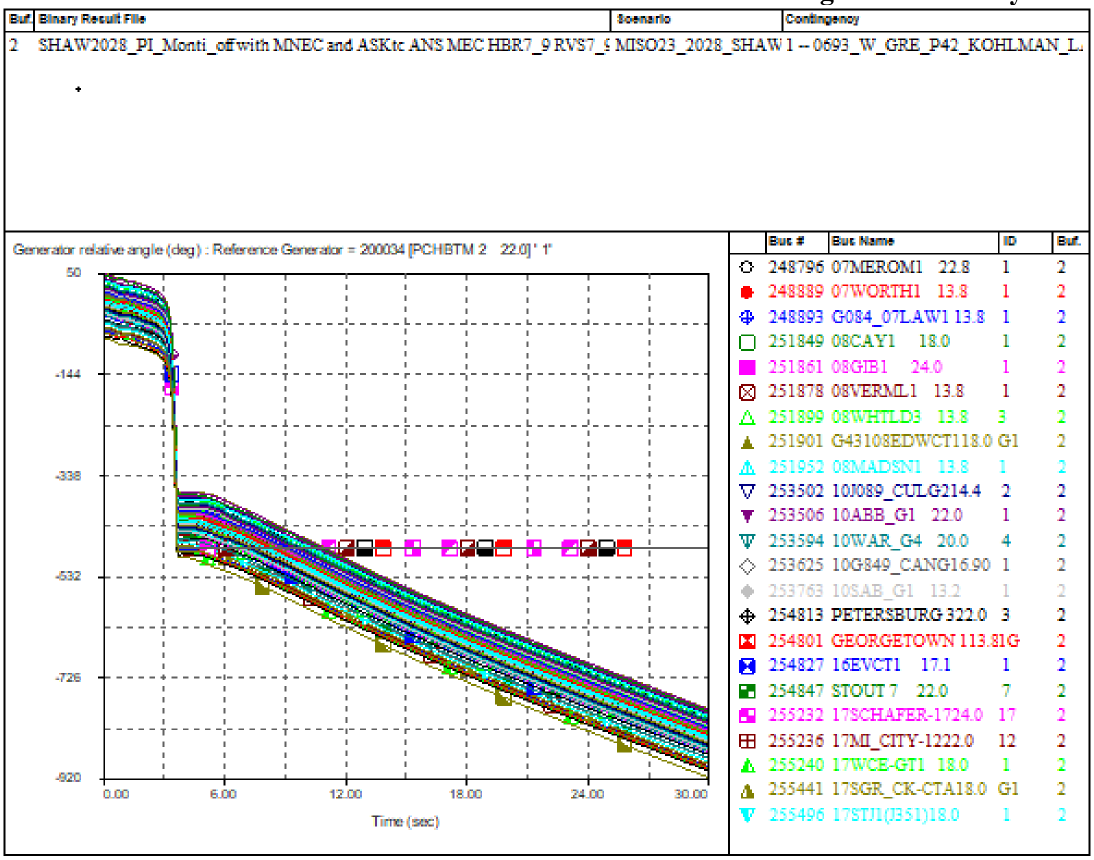

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Figure M1-8
SHAW28 Monticello Retirement Angular Stability

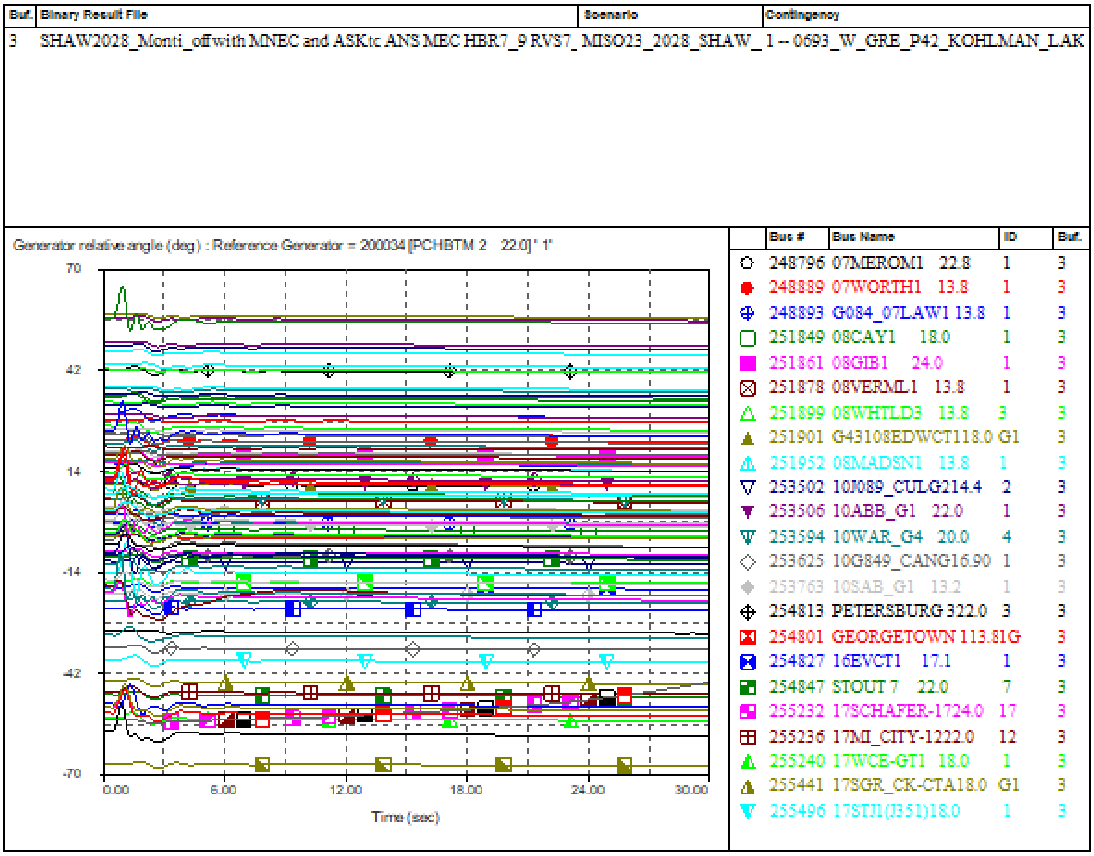

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Figure M1-9
SHAW28 Prairie Island Retirement Angular Stability

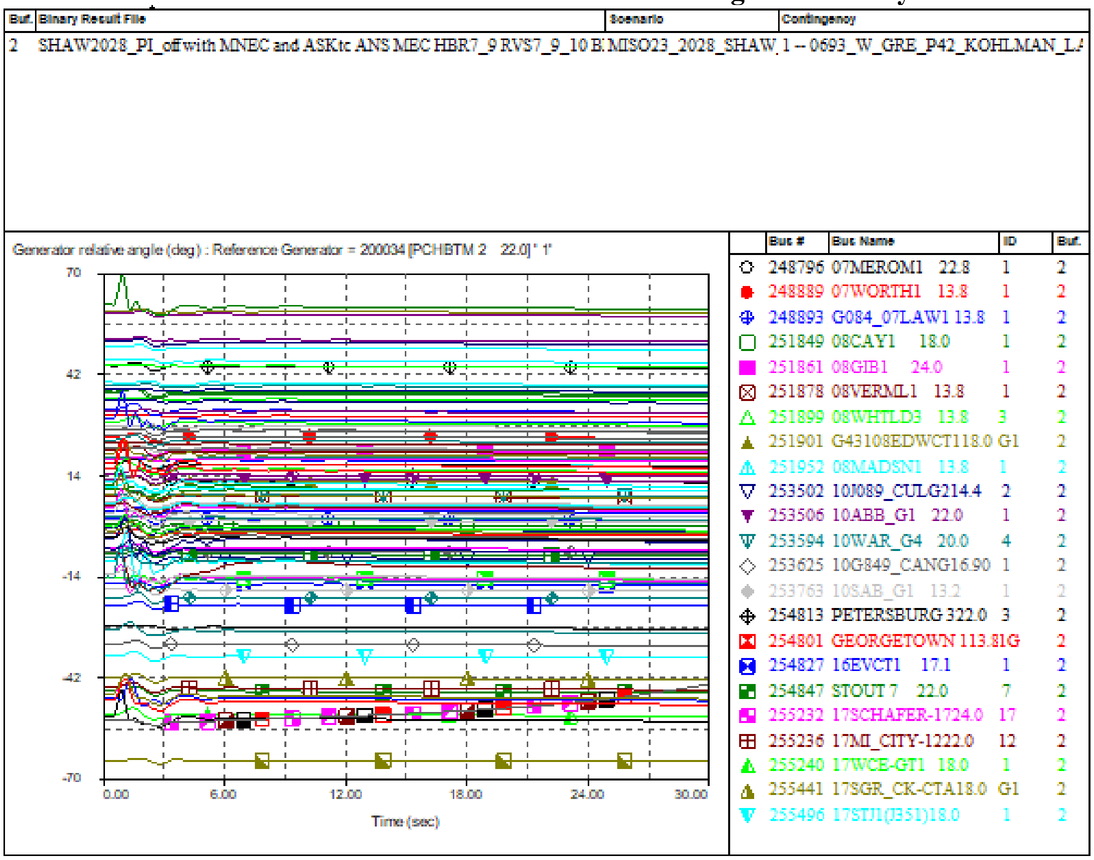

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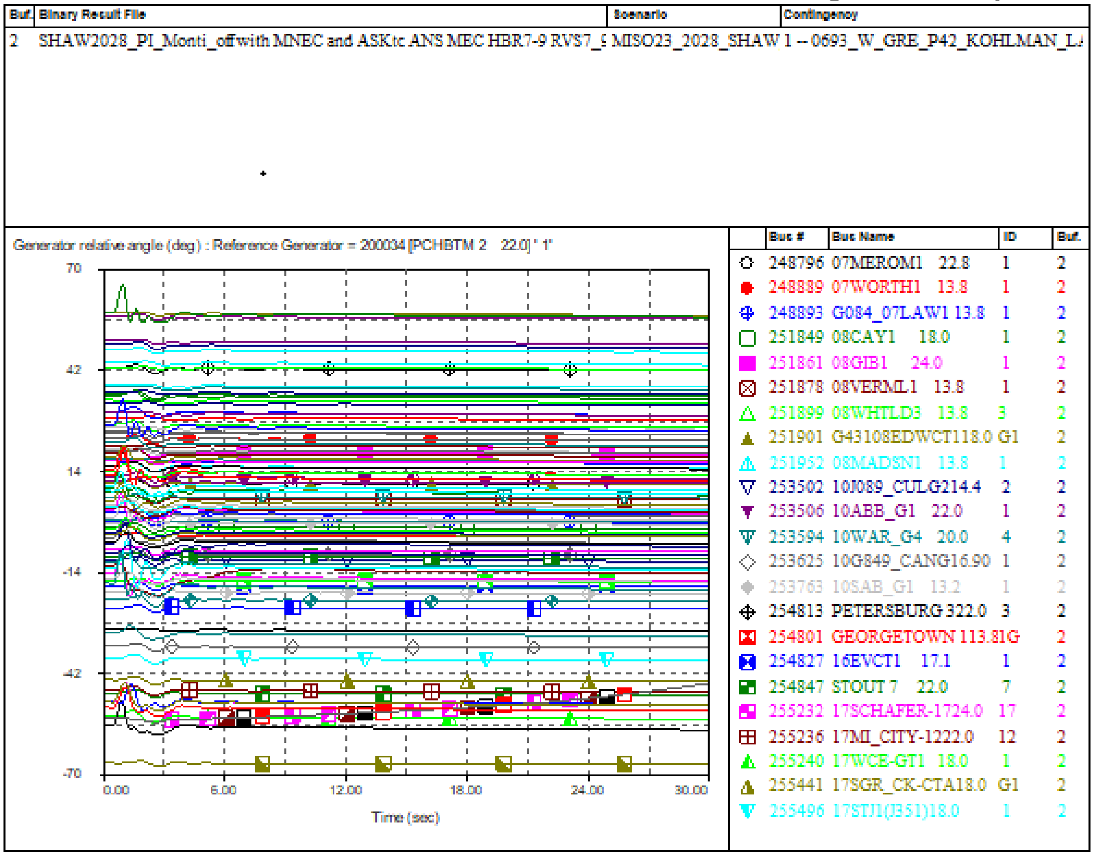
Figure M1-10
SHAW28 Prairie Island and Monticello Retirement Angular Stability



Bus Voltage and Frequency were also montiored with no identified instability.

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6 Observation

Based on the steady state results performed in this study, significant line upgrades and voltages support are needed to mitigate violations with their associated fixed costs as a result of the retirement of the nuclear units:

Table M1-11
Steady State Upgrade Cost Summary

	Summer Peak			Summer Shoulder		
	Line Upgrade (miles/cost $)	**Reactive Support (MVAR/cost $)**	**Total Cost ($)**	**Line Upgrade (miles/cost $)**	**Reactive Support (MVAR/cost $)**	**Total Cost ($)**
Monticello Retire						
Prairie Island Retire						
Monticello and Prairie Island Retire						

Based on the dynamic analysis results performed in this study, significant replacement generation is needed along with the associated annual costs of the generation:

- Summer Peak Load Case, added generation to achieve generator angular stability needed was 521 MW as well as load reduction in the Twin Cities area based on the nuclear generation being retired.
    - Monticello Retire – 10% (537.37 MW) Total Annual Cost [redacted]**.**
    - Prairie Island Retire – 20% (1,074.74 MW) Total Annual Cost [redacted]**.**
    - Monticello and Prairie Island Retire – 30% (1,612.11 MW) Total Annual Cost [redacted]
- Shoulder Load Average Wind Case, added generation to achieve generation angular stability based on the nuclear generation being retired.
    - Monticello Retire – Total generation addition of 706 MW Total Annual Cost [redacted]
    - Prairie Island Retire - Total generation addition of 1,166 MW Total Annual Cost [redacted]
    - Monticello and Prairie Island Retire - Total generation addition of 1,763 MW Total Annual Cost [redated]

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Appendix 1 – Steady State Analysis Thermal Overloads

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APPENDIX N – STANDARD OBLIGATIONS

As part of this filing, we have included Appendices N1 and N2 – the 2021 REO-RES-SES Report and the 2022 REO-RES-SES Report, respectively. These appendices detail our compliance with the verification and filing requirements for the RES, REC retirement, and Green Pricing REC requirement required by Minn. Stat. § 216B.1691, Subd. 3, and were filed in Docket Nos. E999/M-22-85, E999/PR-22-12, and E999/PR-02-1240 and Docket Nos. E999/PR-23-12 and E999-PR-02-1240, respectively. However, because of the legislative amendment to Minn. Stat. 216B.1691, the reporting requirements to Minn. Stat. 216B.1691, subd. 3 have been expanded to include additional reporting detailing, including:

> (5) the number of Minnesotans employed to construct facilities designed to meet the utility's standard obligations under this section;
> (6) efforts taken to retain and retrain workers employed at electric generating facilities that the utility has ceased operating or designated to cease operating for new positions constructing or operating facilities used to meet a utility's standard obligation;
> (7) the impacts of facilities designed to meet the utility's standard obligations under this section on environmental justice areas;
> (8) efforts made to increase the diversity of both the utility's workforce and vendors; and
> (9) for an electric utility utilizing renewable energy credits to satisfy any portion of the electric utility's obligations under this section, the following information:
> (i) the name and location of energy facilities that generated the energy associated with the credits;
> (ii) the dates when the energy associated with the credits was generated;
> (iii) the type of fuel that generated the energy associated with the credits; and
> (iv) whether the energy associated with the credits was purchased by the utility purchasing the credits.

We plan on including this information in our REO-RES-SES reports along with the other information required under Minn. Stat. § 216B.1691, Subd. 3 beginning in our next anticipated filing.

Below, we provide an overview of specific state targets and our compliance with renewable standards and carbon reduction standards.

I. STATE TARGETS

Our Upper Midwest integrated system provides service to five states, each with varying levels of renewable and/or carbon-free energy requirements and objectives. Each state's target is expressed as a percentage of electric retail sales from qualifying resources by a certain date.

Specific targets are as follows:

- North Dakota and South Dakota each have a voluntary Renewable and Recycled Energy Objective to have 10 percent renewable or recycled energy by 2015.[1]
- Michigan – as of November 2023 – has a Renewable Energy Standard (RES) that requires 50 percent renewable energy by 2030 and 60 percent by 2035; and a clean energy standard requiring 100 percent clean electricity by 2040.
- Wisconsin has a Renewable Portfolio Standard (RPS) that requires Xcel Energy to have approximately 12.9 percent renewable energy by 2015 and to maintain that percentage for each year thereafter.
- Minnesota has a renewable energy standard (RES), solar energy standard (SES), distributed solar energy standard (DSES), and a carbon-free energy standard (CFS):
    - The RES requires 30 percent renewable energy by 2020; and 55 percent by 2035.[2]
    - The SES requires 1.5 percent solar energy by 2020, 10 percent of which must be met by solar energy from PV devices with capacity of 40 kW or less.
    - The DSES requires three percent distributed solar energy by 2030.[3]
    - The CFS requires 80 percent carbon-free energy by 2030; 90 percent by 2035; and 100 percent by 2040.[4]

[1] As defined in North Dakota Century Code, 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." South Dakota Codified Law 49-34A-94 contains a similar definition. For North Dakota, we sell renewable energy credits and return proceeds from the sale to North Dakota customers.

[2] Minn. Stat. § 216B.1691 Subd. 2a, "Eligible energy technology standard." Eligible energy technologies are solar, wind, hydroelectric, green hydrogen, and biomass.

[3] Minn. Stat. § 216B.1691 Subd. 2h states that projects must comply with eligibility requirements to count toward the DSES. Eligibility requirements stipulate that the project must be: 10 MW or less; connected to our distribution system; located in our Minnesota service territory; and constructed/procured after August 1, 2023 using a Commission-approved competitive bidding process; etc.

[4] Minn. Stat. § 216B.1691 Subd. 2g, "Carbon-free standard".

II. RENEWABLE STANDARDS

In 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy (see Minn. Laws 2023, chp. 7). First, the statute requires Xcel Energy to achieve a renewable energy standard of 55 percent by 2035. Second, subd. 2h of Minn. Stat. § 216B.1691 amended the distributed solar energy standard (DSES). This amendment mandates that at least three percent of the Company's retail electric sales in Minnesota must be generated from solar energy generating systems. To be counted towards this standard, the solar generating system must have a capacity of ten megawatts or less, be connected to the distribution system, be located in our Minnesota service territory, and be constructed or procured after August 1, 2023.

We plan and operate our NSP generation and transmission facilities as an integrated system, and in the most cost-effective way possible to benefit all our customers across our five Upper Midwest jurisdictions. We also plan our system to comply with the regulations of each state in which we operate. To meet each of the renewable energy objectives in those five states, we maintain a set of banked Renewable Energy Credits (RECs) for future compliance. We maintain our REC inventory in the regional Midwest Renewable Energy Tracking System (M-RETS), which was established for compliance tracking relative to state renewable energy standards. In M-RETS, one MWh of generation from a renewable source equals one REC.

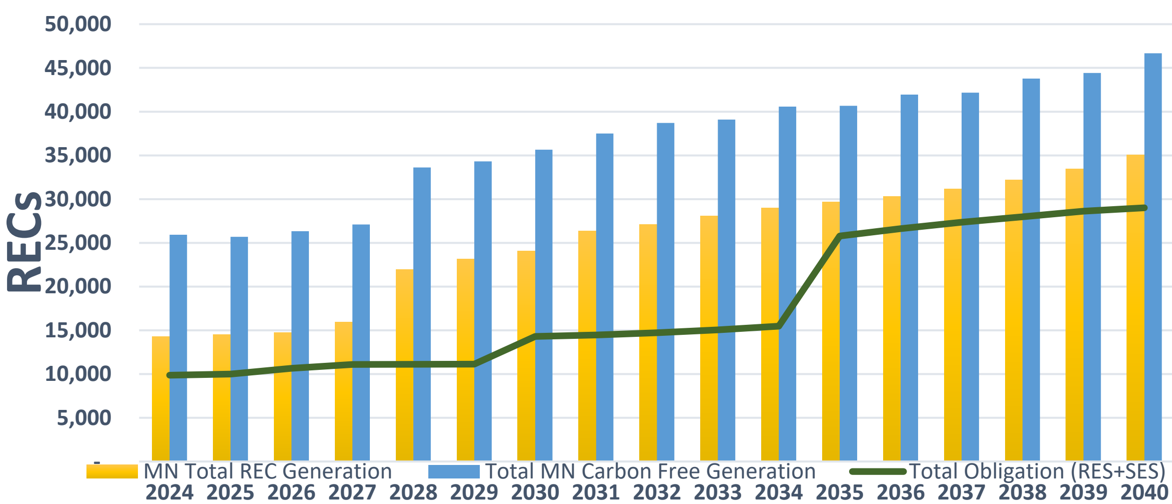
A. Renewable Energy Standard Solar Energy Standard and Compliance

The Company expects to generate a sufficient number of RECs throughout the planning period to satisfy our renewable obligations under our Preferred Plan. Figure N-1 below demonstrates our compliance through the Resource Plan planning period with the Minnesota Renewable Energy Standard and 1.5 percent Solar Energy Standard (SES). Figure N-1 also provides our total carbon-free generations.

Appendix N1: 2021 REO-RES-SES Report is the Company's most recent Minnesota biennial RES Compliance filing and was filed on June 1, 2022, in Docket Nos. E999/M-22-85, E999/PR-22-12, and E999/PR-02-1240.

Appendix N2: 2022 REO-RES-SES Report is the Company's most recent Minnesota SES Compliance filing, which was filed on Jun 1, 2023, in Docket Nos. E999/PR-23-12 and E999/PR-02-1240.

Figure N-1: State of Minnesota Annual RES and SES REC Obligation and Production



III. CARBON REDUCTION STANDARDS

As mentioned above, in 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to create new carbon-free energy standards (see Minn. Laws 2023, chp. 7). The new legislation requires Xcel Energy to generate or procure carbon-free energy equivalent to 100 percent of its Minnesota retail sales by 2040. The law, Minn. Stat. § 216B.1691, also requires Xcel Energy to achieve interim carbon-free standards of 80 percent by 2030, and 90 percent by 2035.

Further, both Wisconsin and Michigan's Governors recently put forward 100 percent by 2040 carbon reduction goals for their respective states' electric sector. Proceedings by those states' Public Utilities Commissions are still in the early stages and have not produced any final compliance requirements for electric utilities.

A. Carbon-Free Standards

The Company is well positioned to achieve compliance with the CFS based on our

Preferred Plan included with this IRP filing. Therefore, the assumptions used in this IRP will result in a plan that complies with the MN CFS for our system.

We note that Table N-1 does not rely on renewable energy credits (RECs), or partial carbon-free energy credits associated with market purchases to demonstrate compliance with the CFS, although it is our understanding that those represent acceptable compliance pathways per the legislation.

Table N-1: 2024 Preferred Plan Carbon-Free Energy

	2030	2035	2040
Carbon-Free Generation (GWh)	46,515	52,681	60,162
MN Allocated CF Generation (GWh)	35,644	40,668	46,666
MN Elec Retail Sales (GWh)	35,725	39,668	44,624
Carbon Free Standard Requirement	80%	90%	100%

The accounting for demonstrating compliance with the carbon-free standard is based on the ratio of the annual utility generation or procurement from carbon-free technologies allocated to Minnesota, and the annual retail electric sales in Minnesota. Compliance with the carbon-free standards is determined by the delta between carbon-free generation and the total of retail electric sales in Minnesota. For example, if a utility were to generate and procure 10,000 kWhs of carbon-free electricity in a year allocated to Minnesota and have 10,000 kWhs of MN retail sales that same year, the utility's generation/procurement would be 100 percent carbon free under the statute. If that utility were to have 12,000 kWhs of MN retail sales that year, the utility's generation/procurement to serve that load would be 83 percent carbon-free.

The Minnesota Public Utilities Commission has opened an Investigation docket[5] into the Carbon-Free Standard (CFS). Parties and the Commission will weigh in on several topics in that docket over the next couple of years, and the Minnesota Commission intends to issue several notices requesting comments on the changes made to Minn. Stat § 216B.1691. The current notice is focused on the clarification of new and amended terms added to Minn. Stat § 216B.1691, including carbon-free, partial compliance, and environmental justice areas.

[5] Docket No. E999/CI-23-151.