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July 1, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN
DOCKET NO. E002/RP-19-368

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, is pleased to submit our 2020-2034 Upper Midwest Integrated Resource Plan to the Minnesota Public Utilities Commission. This plan identifies the resources we will need to serve our customers over the next 15 years.

This Resource Plan charts the path toward achieving some of the most ambitious decarbonization goals of any utility in the U.S. Specifically, we aim to reduce carbon emissions from 2005 levels by 80 percent by 2030, and provide 100 percent carbon-free energy by 2050. This Resource Plan sets out our plan to reach the 2030 goal through retirement of our coal fleet, extension of nuclear, aggressive renewable additions and demand-side management including both energy efficiency and demand response, and a mix of load-supporting, firm dispatchable resources. Not only does this Resource Plan achieve these goals, it does so reliably and affordably.

We look forward to discussing this Resource Plan with the Commission, stakeholders, and the community.

Request for Protection of Trade Secret Information

The Company recognizes and supports the need for transparency in review of our Resource Plan. We also take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers.

Appendix J3: Y2 Study: King & Sherco Unit 3 Coal
Attachment J3 is marked as "Non-Public" in its entirety and is provided with Critical Energy Infrastructure Information (CEII) redacted. Attachment J3 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Allen S. King and Sherburne County Generating Plant (Sherco) Unit 3. While MISO has redacted all CEII from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 14, 2018

Appendix J4: Y2 Study: Monticello, Prairie Island, & All Coal & Nuclear
Attachment J4 is marked as "Non-Public" in its entirety and contains redactions to CEII for the same reasons noted for Attachment J3. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 27, 2018

Appendix N1: NSP 2013 Annual Electric Utility Forecast Report
Certain portions of Appendix N1 are marked as "Non-Public" as it contains private data on individual customers, including names, addresses, and energy usage data for our largest electric customers. This information is maintained by the Company as "nonpublic data" and "private data on individuals" pursuant to Minn. Stat. §§ 13.02 and 13.03. This report also contains forecast data of annual system consumption and generation. This information is trade secret information as defined by Minn. Stat. §13.37(1)(b). This information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use.

Appendix N3: 10-Year Plan: South Dakota
Certain portions of Appendix N3 have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information includes confidential pricing and other contract terms, as well as confidential forecast data. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report
Certain portions of Appendix N5 have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, this report contains forecast data of annual system consumption and generation. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Appendix N7: Annual Report: Solar Energy Standard
Certain portions of Appendix N7 contain information we have marked as "Non-Public" including information identifying customer names, locations, energy usage or bill credits. This information is maintained by the Company as "nonpublic data" and "private data on individuals" pursuant to Minn. Stat. §§ 13.02 and 13.03. We have also marked as "Non-Public" capacity factor information relating to specific Purchase Power Agreements (PPAs). The terms of the Commission approved PPAs require that this information be non-public. Further, this is considered to be "nonpublic data" pursuant to Minn. Stat. §13.02, Subd.9, and is

also "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Appendix R: Study: Interconnection Cost Estimates-CC (Excel Engineering)
Appendix R is marked as "Not Public" in its entirety as it includes information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). As set forth below, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by Excel Engineering.
3. **Importance:** The study contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The study was prepared during the fourth quarter of 2018.

Copies of the filing have been served on Commission staff, the Department of Commerce, and the Office of the Attorney General – Residential Utilities Division. We have also provided a copy to the Minnesota Environmental Quality Board. Interested parties will be able to obtain copies from our web site at xcelenergy.com/UpperMidwestEnergyPlan

Please contact Bria Shea at (612) 330-6064 or bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

/s/

CHRISTOPHER B. CLARK
PRESIDENT
NORTHERN STATES POWER COMPANY MINNESOTA

Enclosures
c: Service Lists

Xcel Energy®

UPPER MIDWEST INTEGRATED RESOURCE PLAN
2020-2034

Northern States Power Company
Docket No. E002/RP-19-368

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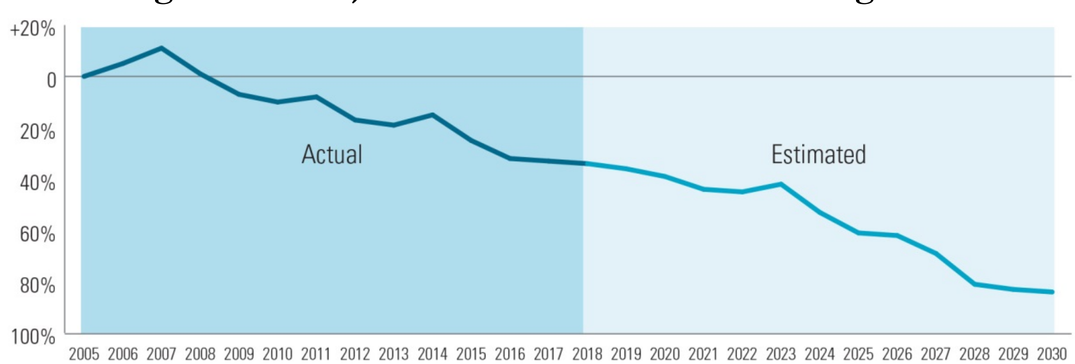
2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN

CHAPTER 1
EXECUTIVE SUMMARY

I. INTRODUCTION

This 2020-2034 Upper Midwest Integrated Resource Plan charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the U.S. Specifically – we aim to reduce carbon emissions 80 percent by 2030, and provide 100 percent carbon-free energy by 2050. This Resource Plan not only reaches the 2030 goal through retirement of our coal fleet, extension of nuclear, aggressive renewable additions, and demand-side management including both energy efficiency (EE) and demand response (DR), and a mix of load supporting, firm dispatchable resources – it embraces technology and innovation and is well-grounded in reliability and affordability. And while the last stretch of total carbon reduction – from 80 to 100 percent – will require technologies that have not yet been developed or deployed economically, we are confident that we can work with regulators, policymakers, and stakeholders to position ourselves so we are prepared to take advantage of the cost-effective solutions that emerge over the course of the next 30 years.

Figure 1-1: Projected Carbon Emissions Through 2030



Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of information sharing as we developed a Preferred Plan. As a result of those efforts, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process. That consensus is represented by an agreement signed by the Company, the Clean Energy Organizations,[1] Center for Energy and Environment,

[1] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

Sierra Club, and LIUNA Minnesota and North Dakota that resolves (among those parties) many of fundamental building blocks of our plan.

Those building blocks include the elimination of coal-fired generation from our system by 2030, as well as the reduced, seasonal dispatch of Sherco 2 until its retirement in 2023. The agreement also includes the acquisition of at least 3,000 megawatts (MW) of utility-scale solar by 2030, and a substantial increase in EE programs, representing an average annual savings of over 780 gigawatt hours (GWh). Finally, the agreement includes support for the Company's proposal to take ownership of the Mankato Energy Center (MEC) combined cycle (CC), which will be central to our reliability strategy as we retire 2,400 MW of coal and integrate several gigawatts (GW) of new renewable resources. The Company's Preferred Plan builds upon this agreement and adds proposals to operate our carbon-free Monticello nuclear plant for an additional 10 years beyond its current license, add a significant amount of DR resources, and construct a new CC at our Sherco site. In total, we have an ambitious plan that supports the Company's goal of reducing carbon emissions 80 percent by 2030, and it moves us toward our ultimate vision of 100 percent carbon-free energy by 2050.

Figure 1-2: Preferred Plan Highlights

Throughout this process, we have taken steps to ensure that we can meet these progressive carbon reduction goals while preserving the reliability our customers have enjoyed for decades. To that end, the Company's engineering and operations teams have conducted extensive analyses to ensure that we can continue to serve customers every hour of every day, even as we progress toward relying on intermittent resources for a majority of our generation. In this work, we have aimed to embrace change while addressing the physical realities of our system and the responsibility that comes with providing a genuinely essential service.

The addition of several gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time. Our Preferred Plan addresses these reliability issues in three ways. First, the extension of Monticello by an additional 10 years and the continued operation of Prairie Island will anchor our grid in around-the-clock, carbon-free energy. Second, we are proposing to take ownership of the Mankato Energy Center and build a new CC plant at our Sherco site in 2026. These dispatchable resources will be critical as we retire 2,400 MW of coal-fired baseload and transition to a system that is nearly 60 percent renewable and intermittent generation. Finally, we propose several firm dispatchable, load-supporting resources – but defer these additions until the latter part of the decade, in anticipation of technological advancements that will improve the functionality and drive down the cost of resources, like storage, that can take the place of traditional gas peaking units.

We also recognize that the achievement of our carbon reduction goals will depend on our ability to keep rates affordable. We believe that our Preferred Plan accomplishes this by keeping annual cost growth below the rate of inflation. The modest cost of our plan is facilitated by our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. Additionally, we believe technological improvements will continue to drive the costs of renewables down, which is a key element in our strategy of proposing significant solar additions in the latter half of the next decade.

We also know that our proposed plan includes impacts both on the communities we serve and our employees. We appreciate not only the challenge – but the stakes for those impacted – and we plan to build on our successful track record of working with our communities, policymakers, stakeholders and employees to successfully manage this clean energy transition.

We further recognize that the agreement underlying our Preferred Plan is simply the beginning of a process. And although elements of our Preferred Plan are captured by the Settlement, the parties to the agreement have not endorsed the entire plan and the Commission has not yet approved the plan. As a result, we look forward to a healthy discussion on the best way forward. That said, we view the agreement – which promises the elimination of coal and the new prominence of solar on our system – as a great foundation from which to work. We believe both the process and outcome of this collaborative effort are a testament to the regulatory landscape in the states we serve, and we look forward to continuing the discussion around this transformational plan and our collective energy future.

II. EXECUTIVE SUMMARY

In our last Resource Plan (Docket No. E002/RP-15-21), we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. We also noted that partnership among our stakeholders, communities, and the Company would become even more important to navigating these changes. In approving our prior plan, the Commission likewise noted that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders.

We are filing this 2020-2034 Upper Midwest Integrated Resource Plan following an unprecedented stakeholder process that included 13 public workshops with topics from the evolving resource planning process, to more technical considerations, such as transmission and system reliability. We also engaged a third-party consultant—Energy and Environmental Economics, Inc. (E3) to conduct independent, parallel analysis to inform the Company's future resource strategy. E3 presented its findings to a diverse group of stakeholders at a workshop in April 2019. We then presented our own preliminary Preferred Plan at our final stakeholder workshop in May 2019.

We believe this combination of a significant internal effort, extensive collaboration, independent expert analysis, and transparency has improved not only the process that led to the development of our Preferred Plan but also the plan itself. In fact, it was through this stakeholder engagement that the Company, the Clean Energy Organizations,[2] Center for Energy and Environment, Sierra Club, and LIUNA Minnesota and North Dakota were able to reach an agreement that addressed many of the cornerstones of our Preferred Plan, including: (1) retirement of our last two coal units by 2030; (2) seasonal dispatch of Sherco 2 until its retirement in 2023; (2) acquisition of the MEC CC; (3) acquisition of at least 3,000 MW of utility-scale solar by 2030; and (4) a substantial EE goal.

We acknowledge that this agreement is just the start of the process – a process that

[2] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

began with the Commission and its request to conduct a holistic review of our baseload resources. As we return to the Commission and begin to engage with the Commission directly in this Integrated Resource Plan docket, we look forward to the opportunity to demonstrate the substantial benefits of our Preferred Plan. It is also true that the terms of the agreement outlined above do not cover all components of our Preferred Plan, and we recognize that stakeholders continue to have wide-ranging perspectives on our collective energy future. We welcome those perspectives as part of this process, and we look forward to more collaboration and iteration as this docket moves forward. That said, we view the agreement as a very good start and a positive outcome from our stakeholder process; we appreciate the Commission setting us on the path; and, we believe the agreement demonstrates that stakeholders and the Company can find common ground and build consensus around key building blocks of a plan that satisfies the needs of our five-state Upper Midwest region – and meets individual state goals as well. Indeed, meeting the varied interests of our integrated system was an important foundation of our planning process.

Both the agreement and our overall Preferred Plan are consistent with the Company's environmental goals. For more than a decade, Xcel Energy has been a leading wind energy provider in the nation and has pursued a successful strategy to transition to clean energy. We have surpassed both national and international goals, including the U.S. commitment under the Paris Climate Accord of 26-28 percent reduction in carbon emissions by 2025. To-date, we have reduced carbon emissions 38 percent companywide from 2005 levels. We are proud of these achievements and grateful to our many stakeholders who have played a role in our journey.

In December 2018, the Company expanded on its commitment to clean energy by announcing industry-leading goals to reduce carbon emissions 80 percent Company-wide by 2030,[3] and to provide 100 percent carbon-free electricity across our service territory by 2050. This 2020-2034 Upper Midwest Integrated Resource Plan charts a path to accomplishing these goals through the elimination of all coal generation on our system by 2030, the addition of over 5,000 MW of renewables, and the expansion of our industry leading EE and DR programs. It accomplishes these environmental milestones while not sacrificing operational reliability or affordability. Specifically, we propose to do the following:

- ***Coal Resources -*** Retire our last two units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early). Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco Unit 2 into Midcontinent Independent System Operator (MISO) on a seasonal basis until its retirement.

[3] From 2005 levels.

- ***Nuclear Resources-*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[4]
- ***Renewable Resources –*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period.
- ***Combined Cycle Resources –*** Acquire and operate MEC and build, own and operate the Sherco CC to satisfy significant capacity and operational need created by coal closures.
- ***Firm Load Supporting Resources –*** Starting in 2031, add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources by 2034.
- ***Demand Side Management (DSM) -*** Include EE programs representing approximately 780 GWh of savings annually through 2034 (compared to average annual energy savings of 444 GWh in our last Resource Plan) and the addition of 400 MW of incremental DR by 2023 with a total of over 1,500 MW DR by 2034.

This plan demonstrates that we can achieve our 2030 goal with existing technologies and resources while maintaining both reliability and affordability.[5] However, it also creates opportunities to introduce emerging technologies as part of the solution. We see opportunities for innovation in our ongoing EE and DR programs. Likewise, we believe the industry will deliver new and improved technologies that will support our long-term need for firm, load supporting resources. The plan also advances a framework that achieves these goals in manageable steps as opposed to transitioning the entire system and grid all at once. By doing so, we can continue to ensure the reliability of our system and maintain flexibility to respond to future market trends, technology advancements, and changing regulatory policies
Below, we discuss our proposed resource mix further, as well as the priorities and considerations that drove the development of our plan.

[4] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[5] As we explained our December 2018 announcement, we recognize that serving customers with 100 percent carbon-free electricity will likely require technologies not yet commercial available, and we look forward to discussing these technological developments in future resource plans.

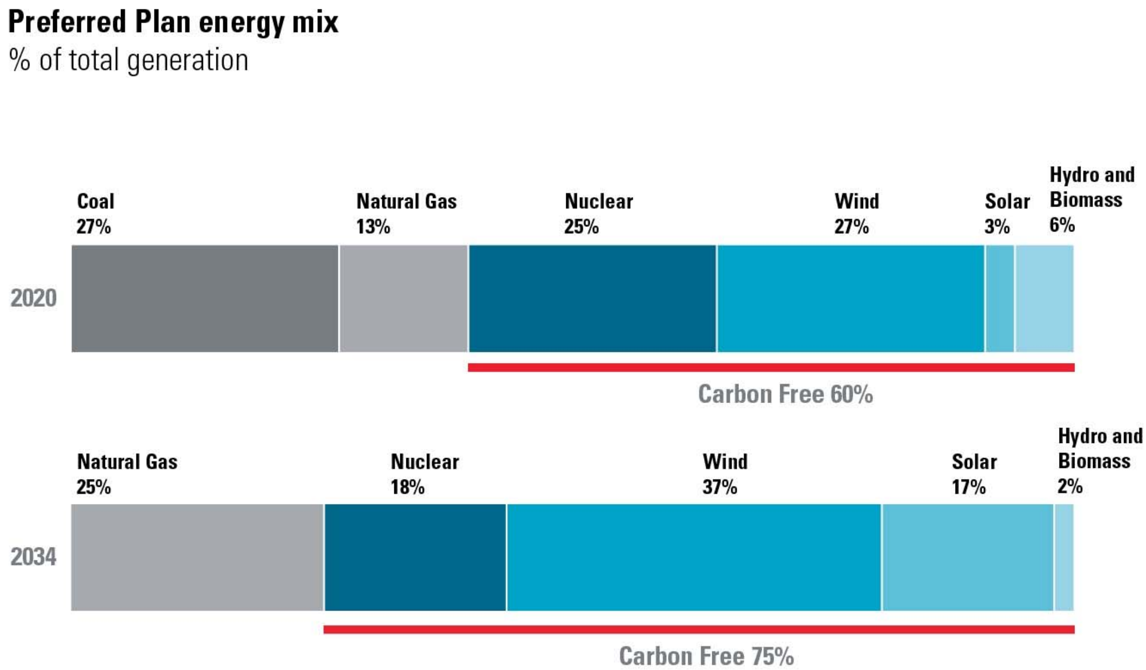
A. Proposed Resource Mix

Our Preferred Plan reflects a significant transformation of our resources. We have more than 1,300 MW of energy resources subject to power purchase contracts that are expiring. Our plan is also informed by an extensive study of all of our baseload resources, completed in response to the Commission's last Resource Plan Order. That study included seven Attachment Y2 studies by MISO and a more traditional NERC-based analysis of our fleet by an external consultant. All of these potential retirements were then studied in conjunction with the addition of significant renewable resources needed to meet our 80-by-30 goal, which identified reliability and stability issues that will need to be resolved as we move through the planning period.

As a result of this work, our Preferred Plan takes a measured approach to adding and retiring resources, and it prioritizes reliability and long-term system planning – as it must. In the first five years, we have no incremental capacity needs and propose only minimal additions.[6] In fact, there are no significant resource additions until 2025 when our first utility-scale solar is proposed. By relying on our existing resources in the near term, we preserve flexibility to respond to changing customer needs and regulatory policies, and we can monitor technological change to ensure we make future resource investments at the speed of value when they are in the best interest of our customers. We will continue our aggressive support of EE and DR and are looking to emerging resources to be part of that solution.

[6] Our actions in the next five years will address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer or program needs, community solar garden growth, and DSM programs.

Figure 1-3: Preferred Plan Energy Mix through 2034



That said, in light of the potential baseload retirements and expiring power contracts, we must address nearly 75 percent of the energy-producing resources on the NSP System during the 15-year planning horizon. We developed the Preferred Plan with an eye toward maximizing cost-effective renewable resources, backed by natural gas to support renewable integration and system reliability, in an effort to minimize market and commodity exposure. By doing so, our system will not be overly reliant on any one fuel source, and we will retain our trademark reliability – along with the flexibility to consider the economics of new resources as our baseload plants retire.

We discuss the components of our proposed resource mix in greater detail below.

1. Coal

With respect to coal-fired generation, our 2020-2034 Resource Plan represents a monumental step forward in transitioning our fleet. Today, as a result of our agreement with the Clean Energy Organizations, Center for Energy and Environment, Sierra Club, and LIUNA, we are proposing to retire our King plant in 2028 and Sherco 3 in 2030 – meaning that Xcel Energy will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan retire approximately 2,400 MW of coal-fired generation in the next decade.

The early retirement of these plants allows us to reduce and ultimately eliminate our reliance on coal, enable additional cost-effective renewable resources, and save customers money. In addition to these retirements and the early retirements of Sherco Units 1 and 2 approved in our 2015 Resource Plan, we are also proposing to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023, which we expect will reduce its carbon emissions in the near term.

This accelerated transition away from coal requires the Company to plan for the retirement of 2,400 MW of coal-fired generation in the next decade, which represents almost one-fourth of the total capacity in our current generation fleet. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing these MWs includes a combination of natural gas CC resources, continued reliance on nuclear generation, large renewable additions during the planning period, and a continued commitment to both EE and DR, all of which will be critical to maintaining reliability throughout this baseload transition. We discuss each in turn below.

2. Nuclear

Carbon-free nuclear generation has been a cornerstone of our generation fleet for nearly half a century. Today, our nuclear plants generate about half the carbon-free energy for our Upper Midwest customers – amounting to the avoidance of about 7 million metric tons of carbon dioxide annually. This is equivalent to removing 1.5 million cars from the road. Our nuclear fleet is therefore critical to meeting our "80-by-30" goal and maintaining that level into the future.

Our nuclear units enable the Company to achieve and maintain our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability. Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical piece of our reliability strategy, which we discuss below.

In light of these considerations and others discussed later in this filing, our Preferred Plan includes operating our Monticello nuclear plant until 2040, along with the continued operation of Prairie Island through its current operating licenses (which expire outside the planning period of this Resource Plan, in 2033 and 2034). By continuing the operation of these plants and extending our Monticello license, we can continue to enjoy the substantial carbon-free benefits these baseload units provide while saving our customers money by leveraging existing assets on our system.

Absent a Monticello operating extension, based on the reliability needs of the system, any suitable replacement resource would add carbon to our portfolio. We simply could not maintain our system reliably, or affordably, given the massive renewable additions and corresponding transmission infrastructure that would be required to replace our Monticello nuclear plant, if it were even possible by 2030, given MISO's current transmission expansion issues.

The recommendation to extend the Monticello unit is supported by its operational performance, which has achieved an average capacity factor of 96.5 percent over the past three years (including a record-setting 99.3 percent in 2018). Moreover, we achieved this performance all while reducing production costs by more than 20 percent since 2015. We believe this performance demonstrates that we can achieve deep carbon reduction along with industry-leading safety and reliability at an affordable cost. For all of these reasons, our nuclear strategy is sound and is in our customers' best interest and consistent with the public interest.

Procedurally, we intend to bring a petition for a Certificate of Need (CON) to address the Monticello license extension request to the Commission in the coming years. In that filing, we will provide detailed capital budgets and O&M forecasts, as well as economic modeling to justify our request. Given that the Prairie Island Units' licenses do not expire until 2033 and 2034, we believe we have time to address the future of these units in our next Resource Plan. We look forward to engaging with the Prairie Island Indian Community, Monticello, and Red Wing as we begin a discussion about the role of nuclear in our energy future.

3. Renewable Resources

Substantial renewable additions are a central component of our energy future and thus a cornerstone of this Preferred Plan – which proposes to add 4,000 MW of cost-effective, utility-scale solar generation and approximately 1,200 MW of cumulative wind resource additions. While the exact mix of wind and solar added to our system may vary (in concert with a variety of factors including technology advancements and price changes), our commitment to renewable energy will not.

In total, our Preferred Plan envisions a system that is approximately 60 percent renewable energy – a level that puts us among those leading the nation. And, while we are confident in our ability to deliver on our reliability commitment at this high level of renewable penetration, we are somewhat cautious at the same time about going much beyond those levels in light of our own experience, as well as recent industry studies regarding the complexity and complications of an exceedingly high renewable grid.[7] That said, some of our customers and municipalities have environmental goals that include the achievement of 100 percent renewable energy to meet their needs, and we are confident we can meet those needs given the substantial renewable additions proposed in this Resource Plan.

The capacity value of renewables combines with our cost-effective gas and nuclear generation to deliver safe and reliable service that will withstand the summer and winter peaks of the Upper Midwest. Significantly, with these additions, there would be enough solar generation to power more than 650,000 homes each year.

Wind generation also continues to play a prominent role in this Resource Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last Resource Plan and our 1,850 MW wind portfolio. By 2024, wind will provide approximately 35 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

4. *Combined Cycle Resources*

In addition to our carbon-free nuclear baseload resources, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables; we can ramp the output of these resources up or down in response to our system's changing needs throughout the day, as renewable resources generate more or less energy due to their variable nature. Finally, dispatchable generation will also help us plan for the expected marginal decline in load carrying capability from renewables as their penetration increases, which we believe could result in additional capacity needs.

To that end, our Preferred Plan includes our acquisition of MEC (a 760 MW two-unit CC), as proposed in Docket No. IP6949,E002/PA-18-702,[8] as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s. As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk

[7] *See* https://twin-cities.umn.edu/news-events/research-brief-planning-future-energy-demand-renewable-energy and MISO's *Renewable Integration Impact Assessment* (RIIA), which we discuss in Appendix J2: Reliability Requirement.
[8] We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy.

As discussed in our last Resource Plan, we propose to locate a CC at the existing Sherco site because it will allow us to cost-effectively address significant transmission issues identified by the MISO Attachment Y2 study, ensure the stability and reliability of the transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota.

Together, our MEC acquisition and constructing the Sherco CC will not materially impact the amount of gas generation on our system. As already discussed, MEC is already an existing resource on our system, and the Sherco CC will primarily offset the retirement of other gas generation on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). This additional gas generation is not only reasonable, but an operational necessity in light of the much larger coal retirements planned – and the large amounts of variable renewable additions we anticipate in the same period.

5. Load Supporting Resources

Reliability is the bedrock of any resource plan. We are particularly focused on the reliability of our system in this plan, however, as we plan for such a large turnover of our baseload fleet and transition to a portfolio that is approximately 60 percent renewable and intermittent generation. We recognize that our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses, so we are steadfastly committed to maintaining our performance when it comes to this core tenant of our business.

Based on the results of extensive reliability studies that we discuss further below, we are proposing approximately 1,700 MW of cumulative additions of firm dispatchable, load supporting resources from 2031-2034. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. That said, because these units are not needed until the out years of our current plan, we have not identified a specific resource type to meet this need. However, with the expected price declines and technology development, between now and the 2030s, we fully expect utility-scale storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced grid investments could position DR to better compete with traditional generation to fill some of this firm dispatchable need. We are committed to pursuing all of these options not only in the longer term, but in the near term as well in order to position ourselves to leverage this technology as it matures.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

By keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan but allow the market to advance as we file future resource plans and continue to collaborate with our stakeholders and the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. *Energy Efficiency*

Our Preferred Plan also proposes to add significant amounts of EE based on the December 2018 *Minnesota Energy Efficiency Potential Study: 2020-2029*. In fact, our proposal includes an annual average of over 780 GWh of savings for 2020-2034. Our last Resource Plan included 1.5 percent annual EE savings assumption, but our current proposal achieves much higher levels of savings – ranging from approximately 2 to 2.5 percent annually. Relative to a 1.5 percent assumed savings level, our proposal achieves more than 200 MW of additional demand savings by 2023, and more than 800 MW by 2034.

7. *Demand Response*

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023 (with a total of over 1,500 MW of DR by 2034). When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In the last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines. As can be seen in our analysis, however, no combustion turbines or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers solar additions as the most attractive resource in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another non-conventional DR program that automates control of various end-uses like HVAC and lighting. We believe the advancement of our grid and technology generally may take the form of less traditional DR, so we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

In this filing, our objective is to bring forward information on all of the viable options so the Commission, stakeholders, and the Company can engage in an informed exchange.

B. Plan Priorities

1. *Reliability*

The foundation of our business is providing safe and reliable electric service, and the purpose of a Resource Plan is to identify the appropriate resources to continue providing that service to our customers. Building on the reliability and stability issues identified as part of our Baseload Study and renewable integration work, and recognizing that many other utilities within the MISO planning area are also planning to retire their baseload units, we made reliability and resilience a primary consideration of this Resource Plan.

To that end, we have conducted a detailed analysis of what resources will be necessary over the full planning period – once many of our baseload units are retired and the renewable resources have taken their place as our primary source of generation. As part of that work, we have paid increased attention to analyses around our winter peak, when solar is diminished and wind facilities can also drop off as a result of extreme temperatures. That analysis points to a baseline operational level of firm resources needed to continue to support a reliable and resilient grid at all hours of the day, on all days of the year. This operational guidance was then used in our modeling tool, Strategist, to inform the resource decisions and ensure that all resource mixes we considered would be operationally feasible and reliable to meet our ongoing need to serve our customers. Below, we summarize how we determined the appropriate operational requirement.

Within a large pool of generation resources and an established wholesale energy market like MISO, there is a tendency for market members to project reliance on market resources based on the size of that pool, rather than the specific performance of those resources and the capabilities of the overall system to deliver additional resources. As we move further into a future that relies less on centralized and dispatchable generation resources, these operational considerations around system and resource capabilities become exponentially more important. In other words, as renewable penetration increases throughout the MISO footprint, it becomes increasingly important to consider the variable nature of these resources and their effect on the overall pool when considering reliability and market reliance. Thus, while we can, and do, still rely on the market, that reliance should be tempered during extreme events, because the nature of these events is such that they tend to impact a geographical footprint that is broader than a single plant or transmission line outage. While MISO is working to address these transmission needs, there is a clear need for more collaboration to enable transmission capability to help support the market's ability to facilitate carbon-free objectives going forward.

Due to the variability of renewable generation, the current generation fleet encounters times in which Net Load (defined as the difference between gross demand and renewable generation supply at a given point in time) is near, or even equal to, the gross demand on the system. This is evident in extreme cases, such as the 2019 polar vortex (when MISO used an average of 6,500 MW resource "reserves[9]" to remain operational), but also during normal winter operations like February 5, 2019, which was representative of conditions we typically experience throughout the winter season. For instance, on February 5th, the system encountered 16 hours of demand greater than 5,500 MW (60 percent of annual peak demand). During this same time, the Net Load was above 5,400 MW, with wind and solar together producing only 6 percent of their installed nameplate capacity (dipping at certain hours to 3 percent). Another example, on July 29, 2018, the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of minus 11 MW – meaning the wind turbines that were online, were taking more power than they were producing. This hour was part of an approximately 110 hour sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in

[9] These reserves consisted of non-firm resources offered by neighboring regional transmission organizations into the MISO market

present planning processes.

This real-world experience reveals several operational truths:

- First, variable resources cannot meet demand in all hours of the year; firm dispatchable resources are necessary.
- Second, simply increasing the level of renewables on the system cannot address resource shortfalls. With an increased level of renewables, we see some improved ability to meet demand but still encounter several hours in which the net load is very close to the gross load. In fact, the amount of additional renewable generation that would be required to meet customer demand in the above scenarios and without other resources could be in excess of 180,000 MW.
- Third, our ability to rely on the MISO market during winter peaking events is limited by periods of extremely low renewable generation across the MISO footprint and a shortfall of these resources compared to their accredited capacity.
- Finally, the current state of battery storage technology does not have the ability to match the duration of such events without significant (and very expensive) over-build of those resources, and DSM programs also lack the scale to significantly impact the analysis.

In light of these issues, we have determined that sufficient firm, dispatchable resources are required to meet the approximate 6,400 MW winter peak load obligation, and we have imposed this requirement in our Strategist modeling as part of this Resource Plan. Figure 4 below demonstrates the calculation of the firm resources used meet this need.

Figure 1-4: NSP System Reliability Requirement Calculation

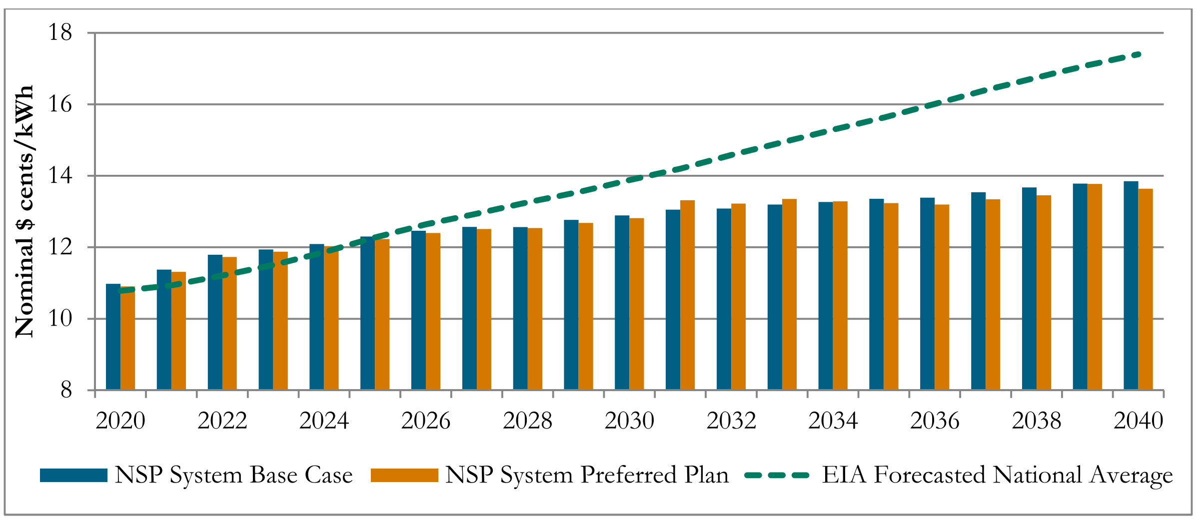
Peak Demand Proxy	6,400 MW
Firm Demand Response Proxy	-200 MW
Firm Market Supply Proxy	-500 MW
Reliability Requirement (Firm Dispatchable Resources)	5,700 MW

Our analysis shows that these resources will help us match the net load gaps discussed above by ensuring that we maintain a stable and reliable energy system for customers, while moving through our baseload transition and achieving our nation-leading carbon goals. We discuss our reliability and operational analysis in greater detail later in this filing.

2. *Affordability*

Another priority for Xcel Energy, and our Resource Plan, is energy affordability. Currently, the average monthly Minnesota Xcel Energy residential customer's electricity bill is below the national average. Our goal is to keep bill increases at or below the rate of inflation – and this Resource Plan positions us well for success. In fact, our Preferred Plan achieves over 80 percent carbon reductions (from 2005 levels) for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the plan period. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in cost is one of the principal benefits of our Preferred Plan. The following graph shows the relative cost growth of our Preferred Plan in comparison to the national average:

Figure 1-5: Preferred Plan Average Rate Impact for the NSP System



To be clear, the resources the Company needs to add over the next 15 years to continue providing safe and reliable service, to comply with state energy requirements, and to address plant retirements and PPA expirations come at some cost. But we believe that cost – which keeps rates at or below the level of inflation – is both modest and appropriate compared to the substantial benefits we have described here.

III. CONCLUSION

Our Preferred Plan – which accounts for more variables and changes than any other previous Xcel Energy resource plan – proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 2
PLANNING LANDSCAPE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this 2020–2034 Upper Midwest Integrated Resource Plan, which eliminates coal-based generation from our system by 2030, proposes to add thousands of megawatts of renewable resources – and charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the United States.

Northern States Power Company-Minnesota is a wholly-owned operating subsidiary of Xcel Energy, Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company-Wisconsin, the integrated NSP System of generation and transmission assets that serves more than 1.8 million customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This Resource Plan builds on our strong foundation of cost-effective environmental performance and the generating fleet transition we began in our last Resource Plan.

Our plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We analyzed numerous assumptions and sensitivities to identify the plan that best meets customer needs, achieves our obligations and goals, and ensures we maintain a resilient and reliable grid. The Preferred Plan we propose emerged as the best suite of resources that balances our planning objectives, as follows:

Figure 2-1: Xcel Energy Integrated Resource Plan Objectives

To understand our Preferred Plan, we first present a Reference Case. The Reference

Case is the baseline scenario identifying the resources necessary to continue meeting our customers' needs, comply with renewable energy requirements, achieve our 80 percent CO_2 reduction from 2005 levels objective, add 400 MW of incremental Demand Response (DR) consistent with the Commission's Order in our last plan, and achieve the significant EE targets identified in the *Minnesota Energy Efficiency Potential Study*.[1]

The Commission's Rules provide the factors to consider in issuing its findings of fact and conclusions.[2] In addition to considering the characteristics of the available resource options and of the Preferred Plan as a whole, resource options and plans must be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service,
B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints,
C. Minimize adverse socioeconomic effects and adverse effects upon the environment,
D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Our Preferred Plan meets these criteria, and provides the flexibility to address the evolving planning landscape, including the changes we expect to the NSP System to achieve our ambitious vision of a 100 percent carbon-free energy mix by 2050. That said, we respectfully request the Commission to approve our Preferred Plan, as follows:

- ***Coal Resources.*** Retire our last two units early: King in 2028 and Sherco Unit 3 in 2030. Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively.
    - Our plan also commits to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement, and working with our employees at, and the communities around, the Sherco and King plants to support them through the transition of our remaining coal fleet.
- ***Nuclear Resources.*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through

[1] Available at: http://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf
[2] Minn. R. 7843.0500, subp. 3

the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3]

   - We expect to initiate a Certificate of Need proceeding with the Commission within the next five years and begin working toward license extension with the Nuclear Regulatory Commission during this timeframe.

- ***Renewable Resources.*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period. We specifically request flexibility in the timing and amounts of renewable additions to take advantage of market and other conditions that we believe will provide value to our customers.
   - ***Wind.*** We are committed to pursuing repowering and/or contract extension opportunities for this resource and we intend to pursue incremental wind resources as needed to meet customer needs in growing customer programs like Renewable*Connect.
   - ***Solar.*** Our Preferred Plan proposes an initial planned addition of 500 MW in 2025. Our plan includes forecasted growth of distributed solar. If actual distributed solar capacity exceeds our expectations, we anticipate this will displace a portion of our proposed grid-scale solar resources.
- ***Combined Cycle Resources.*** Acquire and operate the Mankato Energy Center and build, own and operate (Sherco CC) to satisfy significant capacity and operational need created by coal closures.[4]
- ***Firm Load Supporting Resources.*** Extend the life of Blue Lake Units 1-4 through 2020-2023.[5] Add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources between 2031-2034. Because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe utility-scale storage will be an integral resource used to meet this need.
- ***Demand Side Management.*** EE programs representing 2-2.5 percent of savings annually (over 780 GWh for each of 2020-2034), compared to average

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[4] MEC is currently pending Commission consideration in Docket No. IP6949, E002/PA-18-702. For the Sherco CC, we expect to submit our plans in a separate proceeding.
[5] Pending decision in Docket E,G002/D-19-161.

annual energy savings of 444 GWh in our last Resource Plan, and the addition of 400 MW of DR by 2023. We are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

- ***Storage and Other Emerging Technologies.*** Pursue storage and other emerging technologies, on both a large and small scale.

Finally, as we have previously discussed, system retirements will impact our current blackstart plans, or our ability to restart the system in the event of a catastrophic failure. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

The balance of our Resource Plan discusses the evolving planning landscape, presents our Preferred Plan and the economic modeling framework from which it emerged, and estimated customer cost and rate impacts. We additionally provide Appendices that include the results of our Baseload Study, Load and Distributed Energy Resource (DER) forecasts, and discussion about our Supporting Transmission and Distribution Infrastructure, Environmental Regulations and Compliance, and numerous others.

II. PLANNING LANDSCAPE

Every business that conducts long term planning needs to account for both its internal goals and the external environment within which it operates. In this Chapter, we discuss some of the key internal and external market contexts that affect how we have developed, and plan to execute on, our Preferred Plan – which supports our ambitious carbon reduction vision, to reduce our carbon emissions to 80 percent below 2005 levels by 2030.

Specifically in this section we examine:

- Xcel Energy's Carbon Reduction Goals
- Regional Reliability and Market Constructs
- Distributed Energy Resources (DER)
- Community and Employee Considerations
- Customer Preferences
- Supply and Technology Trends
- Jurisdictional Updates

While all of these factors affect how we develop our plan, a few stand out above others as being particularly influential in this Integrated Resource Plan cycle – chief among them, regional market constructs and renewable integration. While the regional system operator that designs many of our market and planning requirements continues to examine the effects of high renewable adoption on the grid, it has not yet developed robust and forward-looking capacity accreditation constructs to account for how renewables' contributions to peak demand will change over time. This introduces complexity to designing a plan far into the future, and how we carry out those plans.

Likewise, while we are committed to substantially increasing renewables on our system to achieve our carbon reduction goals, we also anticipate facing challenges to integrating this new clean generation, given the delayed interconnection studies and current limited state of open transmission availability. Our ability to connect these new renewables in a cost-effective manner depends materially on constructs that enable careful management of our interconnection rights in the near-to-medium term as well as new transmission in the long term.

These and other factors, such as DER adoption rates, community and employee impacts, and satisfying the needs of five different states, all affect how we developed the Preferred Plan presented in this filing – and the issues we anticipate encountering as we pursue our goals to lead the energy transition while keeping our grid services reliable and affordable.

A. Carbon Reduction Goals

In December 2018, the Company announced its goals to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels companywide, and to serve customers with 100 percent carbon-free electricity by 2050. We believe our 2030 goal is achievable with the clean generation and energy storage technologies available today. We believe our 2050 vision, however, will be achievable only with advancements in new technologies such as: carbon-free dispatchable generation technologies and longer-duration storage that are not currently available at the necessary scale and cost, or carbon capture and sequestration. Until these or other technologies are further developed and commercialized, we will require a certain amount of conventional flexible and dispatchable generation to integrate increasing levels of renewables on the grid.

To achieve our 80 percent reduction by 2030 goal, we anticipate the following elements will be essential parts of future plans, across one or more of our service areas:

- Adding thousands of megawatts of additional renewable resources to our system and incrementally retiring emitting baseload generation, while also incorporating flexible, dispatchable generation to enable grid reliability throughout this transition;
- Operating our carbon-free nuclear units at least through the remainder of their licenses, with the potential for license extensions;
- Supporting the strategic electrification of certain end uses and enabling flexible demand, which will help to reduce carbon emissions in other sectors while also providing flexible loads to help integrate more renewables;
- Investing in critical infrastructure, such as transmission and advanced grid technology on our distribution system, to integrate the DER our customers choose, as well as improve reliability and the customer experience.

These goals, the science behind them, and the path we will take to achieving them, are all detailed further in Appendix E: Xcel Energy Carbon Report:Building a Carbon-Free Future.

With these aggressive carbon goals in mind as one of the main tenets of our Preferred Plan, below we discuss the key forces that affect how we have developed, and plan to execute on, our Preferred Plan.

B. Regional Reliability and Market Constructs

The Company's Upper Midwest system is part of the Midcontinent Independent System Operator (MISO) market. MISO is charged with several responsibilities, chief of which are overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix relying on more variable renewable resources.

1. Reserve Margin

One of MISO's core responsibilities includes administering resource adequacy requirements to enable utilities like us, and other Load Serving Entities (LSEs), across the region to fulfill their obligation to serve customers reliably. Trends are emerging, however, that raise questions regarding how planning constructs will adapt to ensure the system remains reliable as emitting, but stable, baseload generation continues to retire and be replaced by clean, but variable, renewable energy.

MISO and its system reliability oversight organization, the North American Electric Reliability Corporation (NERC) undertake studies to determine the appropriate level of reserve capacity that should be maintained, what affect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future.

MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 report, MISO established a reference planning reserve margin of 17.1 percent for the 2018-2019 planning year; in other words, they determined that the total installed capacity available on the system should be 17.1 percent higher than the system's peak load.[6] This reference threshold is provided to the NERC, which sets standards and studies

[6] MISO's PRM for the 2018-2019 Planning Year indicates a PRM for both installed capacity (ICAP) and a rating that derates capacity to account for potential outages (called UCAP). The UCAP PRM for the 2018 planning year is 8.4 percent These two measures of PRM are discussed further in the next section on Minimum System Needs.

reliability across the continent, and of which regional system and transmission operators like MISO are a part.

As part of its oversight and governance activities, NERC conducts a reserve margin analysis across all system operators in North America, in a report called the Long Term Reliability Assessment (LTRA). The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[7] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

It is important to note that retiring some baseload generation and transitioning to a cleaner grid with more wind and solar does not present an insurmountable challenge; indeed we are proposing to retire all of our coal by 2030. Rather, the transition will need to be actively and carefully managed, likely with incremental retirements and supporting transmission upgrades that are carefully studied.

2. *Renewable Integration Challenges*

In addition to challenges around baseload retirement issues, we also see planning issues developing around how renewable additions are evaluated for their reliability impacts. In the aggregate, when MISO has studied high levels of renewable penetration on the grid, grid instability increases and capacity values of variable resources decline, sometimes significantly. Retaining firm dispatchable generating units helps ensure the system will continue to operate reliably.

MISO has also recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, which creates uncertainty in the resource planning process. We discuss these renewable integration studies and specific capacity accreditation issues in more detail below.

[7] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

a. Renewable Integration Impact Assessment

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. The *Renewable Integration Impact Assessment* (RIIA) seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources, specifically by examining operational adequacy, transmission adequacy, system stability and resource adequacy limitations.

In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these scenarios; while they run for fewer hours than the current market constructs would warrant, they need to be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

Further, at high levels of wind and/or solar adoption, the RIIA study found that appropriate resource adequacy values to assign these resources degraded, sometimes significantly from current levels. As a key piece of planning our future system, these resource adequacy capacity accreditation values are discussed in more depth below.

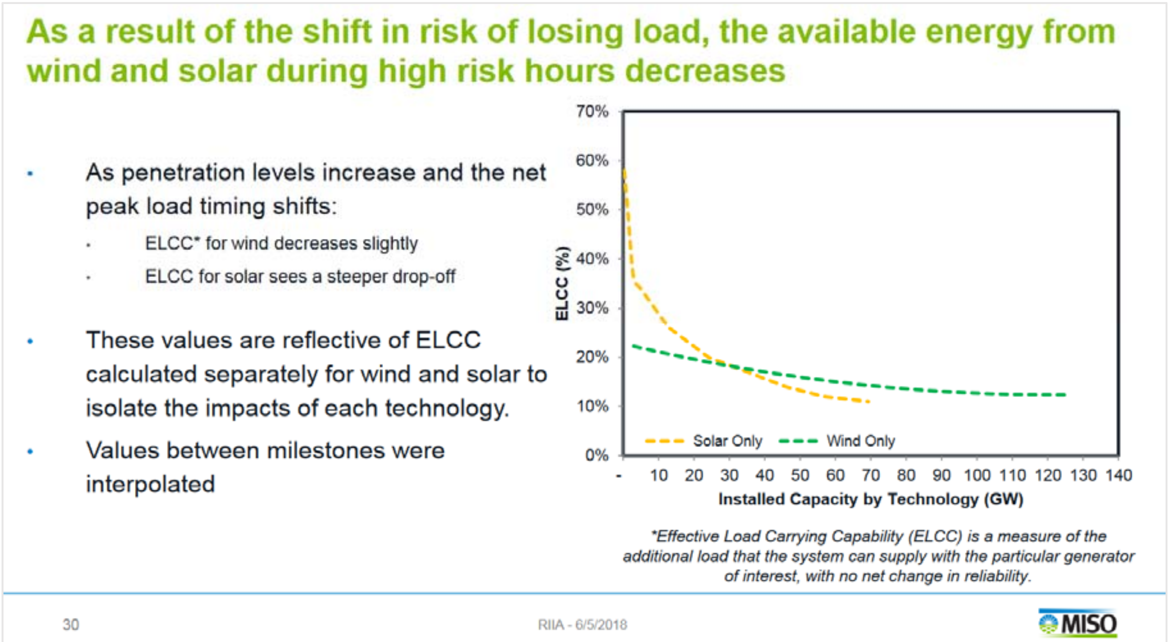
b. Capacity Accreditation Values

Variable renewable resources such as wind and solar are becoming more cost competitive and utilities across the region, including the Company, are increasingly adopting these technologies as important components of their resource mixes. This generation is largely displacing more traditional, thermal dispatchable units. As variable resources are dependent on natural resource availability in a given moment (i.e. wind blowing or sun shining), their capacity does not replace retiring dispatchable units one-for-one in terms of the amount of energy it produces, or assurance that this capacity will produce energy when needed. To account for this, MISO applies a certain accreditation discount to these resources to get a more appropriate probabilistic view of how much capacity can be counted on to contribute to peak demand across the year. This is captured in a measure called the Effective Load Carrying Capability (ELCC).

These administratively set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns wind generation an average ELCC value of 15.7 percent; meaning that for every 100 MW of wind installed, only 15.7 MW can be counted as capacity toward the planning reserve margin. For new solar resources, in the absence of an observed historical value, MISO assigns the current initial year default ELCC of 50 percent. The appropriateness of these values in reflecting actual grid conditions is dependent on the pace at which wind and solar penetration increases on the grid, and subsequently how MISO conducts review and adjusts the values. The ELCC is currently evaluated as an annual average, and forward values are not projected.

In reality, however, the capacity value these intermittent resources can provide are subject to diminishing marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the last unit. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed, and this value continues to drop off at higher levels of adoption. Further, in particular for these variable assets, the realized capacity value may change throughout the year, as the capacity value a wind or solar plant can provide reasonably changes in accordance with seasonally variable environmental conditions.

Figure 2-2: Modeled Wind and Solar ELCC as Penetration Increases[8]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the administratively-set annual average ELCC levels in our planning that MISO has established for today's market.

While we recognize that it is difficult for MISO to accurately project future wind and solar penetration levels and load shapes (two key variables in determining future ELCC values), this presents a key challenge as we plan our future system. As the ELCC construct does not currently provide forward-looking values, we have to apply current values to our resource modeling process, even though we are modeling 15 years into the future. However, we know in reality that these values will degrade as we and others add variable renewables to the MISO system, and so what appears to be a net capacity surplus today may look rather different in future assessments.

It is worth noting here that we may encounter changing assumed resource adequacy contributions for use-limited resources in the future as well. In general, resources such as DR and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[9] Notably, MISO is also considering changes to how it accounts

[8] MISO. *"Renewable Integration Impact Assessment"* Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf
[9] *See* the E3 Study in Appendix P2 for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

for DR's capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently depend on as a baseline resource in our portfolio, in addition to that which we may select in this or future resource plans, may not yield the same benefits in future years as we have historically expected.

c. Interconnection Queue

The current state of grid interconnection processes and transmission capabilities in MISO introduce complexity not only to our planning processes, but also how we execute on the plan.

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 a number of months behind, due to the large volume (including speculative requests) and a generator interconnection process that allows late withdrawals from the queue with limited consequences. Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And where projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the project's economic viability. MISO's interconnection challenge is multi-faceted.

First, there is a substantial volume of capacity currently in the queue requesting study and interconnection approval. As of early June 2019 there were over 100 GW of new capacity in the active MISO queue (although this number has fluctuated substantially), the vast majority of which is comprised of wind and solar projects.[10] Each cycle of the DPP is handling expanding levels of requested capacity; for example, the recently completed cycle for the MISO West region (started in August 2016) started out with 31 projects totaling just over 5,600 MW.[11] The April 2019 DPP study cycle,

[10] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Siemens (August 20, 2018). Available at: https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[12] While the level of proposed new renewable project is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development or representing duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and Multi-Value Projects (MVPs) were able to integrate large quantities of new renewable power and socialize transmission infrastructure costs across a larger swath of benefitting MISO customers. However, wind power in particular expanded on the MISO grid faster than expected, and the interconnection capacity afforded by these projects has been largely used. Since then, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this means that, if new generation projects in the queue want to interconnect, the generation interconnection study process identifies substantial additional transmission system upgrade costs and assigns them to the generation owner(s). In the aforementioned MISO West DPP cycle that recently completed, for example, the approximately 5,600 MW of proposed projects were expected to incur approximately $3.2 billion in transmission upgrades, if all were to interconnect to the system.[13] These assigned high-cost transmission system upgrade requirements can sometimes render projects uneconomic, forcing a queue withdrawal and additional MISO study on the remaining projects.

d. Regional Seam Issues

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges.

Within MISO, the transmission system is showing constraints and the resulting curtailment slows our progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east such as the Minneapolis–St. Paul area and load centers across the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times, operating at its limit.

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[12] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf
[13] "MISO DPP 2016 August West Area Phase 1 Study." Siemens, September 2018, at xvii.

The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient, keeping us from fully utilizing the inexpensive and clean energy to which we have access; but, without additional transmission capacity, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to bringing onto the system, and utilizing, more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost.

Second, although our load and generation sit within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. Mitigation Efforts

In response to direction from FERC and in recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, they allow generation owners to leverage existing interconnection agreements to maximize utilization and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near term challenges to additional renewable capacity, they do not address all challenges (in particular our ability to depend on neighboring regions for renewables and maintaining reliability) and we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially viable, but also to generation owners that are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if we retire existing assets without the ability to re-utilize that interconnection capacity. Recognizing these issues, MISO filed and received approval for a proposed Replacement Generator Process that would allow current generation owners to retain and re-utilize these interconnection rights where a resource plans to retire, within certain technical limitations on the new generator's attributes. The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new MISO tariff provisions, the new generation resource would need to have an in-service date not later than three years after the existing generator ceased operation. Importantly, these projects would be studied outside the traditional DPP timeline, with the intention of avoiding the significant delays associated with that process, as described above.

b. FERC 845

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*[14] that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process. The Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection, as the addition of this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site.

While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage). We expect that generator replacement, Net Zero, and other FERC Order

[14] See Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043 (2018) (Order No. 845).

implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[15] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be resolved in the near term.

C. Distributed Energy Resources

At the same time as we work to clean our power supply, we also recognize that customers are now exercising more choice around how and from where they consume energy. This is a key consideration as we plan our resource mix for the next 15 years.

Some customers are choosing DER that can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the EE enabled by a smart thermostat or time of use electric rate. To-date, community solar gardens makes up the clear majority of the DER on our system in the Upper Midwest.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to enable load shifting away from peak hours.

There are also DER coming onto our grid, in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options

[15] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076

to encourage that adoption.

The transportation electrification initiatives we have implemented and continue to develop are not only enabling customer choice, but also to the broader economy in helping to meet greenhouse gas (GHG) emissions reductions goals. The transportation sector is now the leading contributor to Minnesota's overall emissions,[16] and as our system (and the state's electric sector more broadly) continues to transition to a cleaner energy mix, transportation's share of GHG emissions will continue to expand. This shift highlights an opportunity for the electric sector to facilitate GHG reductions in the transportation sector, as electricity is increasingly used for transportation fuel.

While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduce uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

One tool we have to mitigate this DER and electrification uncertainty is our Integrated Distribution Plan (IDP) and grid modernization efforts. Our IDP process and proposed investments will help us leverage DER and new load to enable more flexible demand management, improve reliability and, we anticipate, enable better decision-making about large-scale investments as well. In our last IDP we discussed these enabling technologies, which include: Advanced Distribution Management Systems (ADMS), which will allow us to better integrate DER onto our grid and maintain reliability; the Field Area Network (FAN), which enables two-way communication from field devices and Company back office operations; Advanced Metering Infrastructure (AMI), which enables time of use rates by metering consumption at smaller time intervals; and automated, remote reliability-sensing and enhancing technologies such as and Fault Location, Isolation, and Service Restoration (FLISR). Many of these investments will help us develop capabilities to use load more flexibly. We also hope to enhance the customer experience by creating new programs and offerings that fit their needs and preferences based on the capabilities these investments provide.

Our Preferred Plan is substantially dependent on anticipated customer load, which incorporates the best estimates we have about customer adoption of DER, as well as robust statistical forecasting methods. We have also modeled sensitivities to address some of this uncertainty. But we still often do not have visibility into which

[16] See the Minnesota Pollution Control Agency's statewide GHG inventory data, available at https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.

technologies, and at what pace, customers will adopt and thus, how that changing load will affect our grid needs in the future.

D. Community and Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. This is particularly true of our coal facilities, where the plants are prominent places of employment and contributors to the property tax base in the community. This is why we make efforts to spur economic development in locations where our current units will eventually be phased out.

For example, since our most recent Resource Plan, where we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with local units of government, community stakeholders, and the State to draw new development to support the local economy. This includes a planned CC generating unit at the Sherco site, the relocated Northern Metal Recycling facility, and, prospectively a new Google data center with energy matched by a wind facility. Some of that activity (e.g. the Google data center) is also anticipated to spur new renewable energy development on our system.

Related, we are participating in a study overseen by Center for Energy and Environment (CEE) that will examine the impacts of the large baseload generation plants in Minnesota on the host communities. The other participants in the study include the Coalition of Utility Cities, Minnesota Power, and the Prairie Island Indian Community. The study will consist of a quantitative and qualitative component. The quantitative component of the study is similar to the study we conducted for Sherco 1 and 2 in our last Resource Plan. For the qualitative component, CEE will engage with host community residents and business to gauge awareness, opinions and concerns around potential power plant closures. Efforts on both components are underway and we will supplement this Resource Plan filing when each component is completed. As this docket progresses, we expect to be able to incorporate further findings and hold additional discussions incorporating the finalized report outcomes. Further discussion of the scope and status of this study is included as Appendix O2.

In addition to community impacts, we are also aware that these plant closures impact our employees and their families. With this in mind, and consistent with our past practices, we will work with these impacted employees to transition them to other Xcel Energy plants or areas of the company. In the past, when plants have been closed or converted (and impacted headcount) we have provided résumé writing services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job relocations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to-date.

Moving forward we will work with local unions and set a course to negotiate multiskilling for our impacted sites. This skill set will position our employees for other job opportunities within Xcel Energy. As we get closer to closure dates, temporary workforce will be utilized to back fill benefit employees who have relocated to other positions within the company. This strategy lessens the burden and stress for benefit employees to find positions, as plants near closure dates. In addition, plant management, Work Force Relations and Human Resources will work together with other business organizations within the company to help coordinate interviews for affected employees.

And, as we continue toward achievement of our aggressive carbon goals, we will continue to make significant investments in clean energy in the states we serve. As we do so, we will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

E. Customer Preferences

Our Upper Midwest system continues to serve a diverse mix of customers with varied interests and preferences. While most customers continue to prioritize affordability, we have seen increasing interest in sustainability, carbon reduction, and clean energy objectives. Again, these are important considerations to keep in mind while planning our resource mix for the future.

1. Municipal

Cities and municipalities are increasingly setting and developing strategies around sustainability and climate goals. In fact, there are 11 cities in our Upper Midwest jurisdiction that have set carbon reduction or renewable energy goals. Minneapolis is the most prominent example, as evidenced by the Clean Energy Partnership that had just started when we filed our last Resource Plan. Since then, the partnership has flourished and advanced, helping to achieve progress toward the city's sustainability goals. Other municipalities and communities are also developing goals and action plans around renewable energy and climate goals. We work with many of these communities through our Partners in Energy program to support achievement of these goals.

2. *Commercial and Industrial Customers*

Our commercial and industrial customers place a high priority on keeping costs low to remain competitive in their own markets. This is particularly true of large industrial customers, where energy costs can make up a substantial portion of their operating expenses. However, corporate efforts to achieve sustainability goals are also increasing, both in the US broadly and within our system. And as the cost of renewable energy declines, affordability and sustainability goals increasingly go hand in hand. Within our system, several of our corporate customers are co-members of the Minnesota Sustainable Growth Coalition, which is a business-led public-private partnership working to advance clean energy and other sustainability and circular economy objectives. We hear from these and other corporate customers across our Upper Midwest system that sustainability and clean energy are important to them, and they want us to offer products that meet these needs, and Renewable*Connect is one such product.

In 2015 we worked with customers to develop Renewable*Connect. The program achieved full subscription in its first year, and in January 2019 we filed for an expansion of this program, and included an option for high load factor customers (i.e. those that operate continuously during the day) to be served primarily with competitively priced wind and a smaller portion of solar. Significantly, this program advances the sustainability goals of the participating companies without creating additional costs that must be carried by other, non-participating customers. In 2019, we also developed a new program called Certified Renewable Percentage (CRP). The CRP is a new Renewable Energy Certificate (REC)-based accounting methodology that clarifies the percentage of our system energy delivered to customers that is renewable. The CRP is not a subscription service or program customers need to enroll in. Instead, the Company will retire sufficient RECs on behalf of all our retail customers such that the total RECs retired annually reflects the portion of delivered energy that is renewable. This will allow all retail customers to claim the percentage of renewable energy on the system as the starting point towards their sustainability goals.

Our willingness to work with customers to balance clean energy objectives and affordability needs, while facilitating economic development opportunities, has also attracted new customers to the service area. The new Google Data Center slated for development in Becker is a clear example. Google has an objective to match 100 percent of its energy consumption needs with renewable energy purchased from incremental projects, and has future plans to go even further by sourcing carbon-free energy for its operations on a 24/7 basis. We were able to work together with Google to develop a proposal to help it achieve its renewable energy goals.

3. *Residential Customers*

Residential customers likewise tell us that they value choices and clean, affordable, reliable energy. In response, we have developed programs that offer more convenient payment options, rebates for EE upgrades, and the chance to reduce the environmental impact of their consumption by choosing renewable energy. Customers are taking advantage of these programs in large numbers – and they have expressed strong satisfaction with their ability to select programs that best meet their individual energy needs.

F. Supply and Technology Trends

Trends around the supply of generation and energy storage equipment we need to fulfill our resource plan have a significant impact on the mix and timing of our resource proposals.

In the years since our last Resource Plan, wind and solar technology costs have continued to improve overall; solar in particular has experienced significant cost declines, with installed costs falling over 35 percent on average since 2015.[17] Consistent with past years, we generally expect wind and solar capital costs will continue to decline, although at perhaps a slower pace as these technologies advance on their respective maturity curves. We also expect technology advancements improve capacity factors. These two factors continue to improve the cost competitiveness of wind and solar resources in real terms, changes to incentive policies notwithstanding, relative to the other resource options we may consider. For example, the National Renewable Energy Laboratory projects that large-scale solar prices could decline 17 percent in real terms over the next 10 years.[18] For modeling purposes, however, our generic representations of these resources are static in terms of capacity factor and accredited capacity, and we have represented the combined future cost and performance trends through the levelized energy cost forecast for these technologies.

We also continue to examine the role energy storage can play in meeting our system needs. The Company has been developing our experience around the type of services energy storage can provide to our system, through the operation of an existing

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[17] Bolinger, Mark and Seel, Joachim. *Utility Scale Solar 2018 Edition.* Lawrence Berkeley National Laboratory September 2018. Available at: https://emp.lbl.gov/utility-scale-solar

[18] This projection reflects data provided by the NREL's *Annual Technology Baseline* report, which we use in our modeling. This trend reflects changes in projected solar levelized costs in real terms (2016$) and are not adjusted for the potential impact of tax credits.

pumped hydro facility in Colorado and several pilot battery energy storage installations across Xcel Energy's service areas. Technologically, we expect grid-scale energy storage will support our clean energy goals in the future, by helping us maintain grid stability and supporting peak management while integrating the higher quantities of intermittent renewable generation we envision on our system. We are committed to pursuing this technology although challenges remain, in particular for battery energy storage, to managing seasonal renewable energy variability and longer duration demand-shifting needs.

From a cost perspective, battery energy storage has experienced significant improvements over the last few years and we would expect battery energy storage costs to further decline going forward. There are also other battery chemistries and different types of storage that may emerge as technology research and development continues. While we are confident utility-scale battery storage will be a part of our long-term resource mix, we are also evaluating the potential for near-term battery storage around our service territories to fulfill distribution system or other needs.

Finally, as we have noted, achieving our 100 percent carbon-free electricity by 2050 goal will require further development of technologies that have not yet been identified and commercialized. While not included in our resource planning optimization, we continue to monitor industry activity around other emerging technologies that may contribute to achievement of our goals. In addition to potential new battery chemistries mentioned above, potential emerging clean energy technologies include advanced nuclear reactors, carbon capture and storage applications, hybridized gas-hydrogen generators, other types of energy storage technologies beyond batteries, and others. As new technologies achieve commercialization, we will remain technology agnostic as we consider including them in our future resource planning analyses.

G. Jurisdictional Updates

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest system – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. Below we provide a brief overview of key prevailing and emerging energy policy in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan, where these objectives may affect our future planning for the Upper Midwest system as a whole.

1. *Minnesota*

In 2007, Minnesota passed the Next Generation Energy Act, which set successive, economy-wide greenhouse gas reduction goals relative to 2005 levels; 15 percent below reduction by 2015, 30 percent below by 2025, and 80 percent below by 2050. Since that time, the electric sector has outpaced emissions reductions in all other sectors, achieving a 29 percent reduction below 2005 levels by 2016 (the most recent year reported). However, the state has missed its economy-wide goal, achieving approximately 12 percent reduction over the same time period.[19] This data drives our view that the electric sector can, and likely must, facilitate reductions in other sectors, such as transportation and building energy use, if Minnesota is to meet its economy-wide carbon reduction goals.

Specific to the electric sector, the Minnesota Renewable Portfolio Standard, passed in 2007, remains our prevailing clean energy requirement. The 2019 session included passage, however, of energy storage provisions that (1) enable utility-owned energy storage pilot projects, and clarifying cost recovery for such pilots, (2) requiring resource plans to include an Energy Storage Systems Assessment, including how storage may contribute to generation and capacity needs and ancillary services, and (3) requiring a cost-benefit study of energy storage systems by the Department of Commerce.[20] We provide our Energy Storage Systems Assessment in Appendix F7.

2. *North Dakota*

Since our last Resource Plan, we submitted a Resource Treatment Framework (RTF) simultaneously to the Minnesota Public Utilities Commission (MPUC) and the North Dakota Public Service Commission (NDPSC). The RTF filing was submitted to the NDPSC in compliance with a Commission Order adopting the Negotiated Agreement in the Company's last rate case,[21] with the purpose of establishing a framework to address the costs and benefits of the Company's Upper Midwest system resources in a way that was both fair to all customers and aligned with North Dakota's policy objectives.

In the RTF, we developed a proposal that evaluated four potential implementation structures: (1) legal separation of the North Dakota portion of the system; (2) pseudo

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[19] *See* Minnesota Pollution Control Agency "Greenhouse Gas Emissions Data." Available at: https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data

[20] "19-5227 – Omnibus Jobs, Economic Development, Comerce and Energy." Available at: https://www.senate.mn/committees/2019-2020/3098_Committee_on_Jobs_and_Economic_Growth_Finance_and_Policy/19-5227.pdf

[21] See North Dakota Case No. PU-12-813. In Minnesota, the Company submitted the RTF consistent with our commitments made in MPUC Docket No. E002/M-16-223

separation, applying generator-specific cost/benefit allocations; (3) proxy-pricing, which would replace the cost of a disputed generation resource with a proxy price deemed acceptable; or (4) gaining regulatory alignment in the selection of resources, so that all states could fully participate in the integrated NSP system. Our intent was to seek a framework solution that can not only address current resource disputes, but also those that may arise in the future.

Our initial proposal would have legally separated the North Dakota portion of our service area into a separate operating company, with pseudo-separation identified as a second best option. Under the legal separation framework, we felt confident we could retain the benefits of economies of scale in our resource planning, yet be able to customize resource portfolios for certain states, to the extent necessary. Pseudo-separation could also prove feasible, if each state agreed to the method by which we would propose to conduct these cost allocations.

In response to this proposal, the North Dakota Staff recommended against legal separation, instead preferring a solution that used a form of proxy pricing to determine appropriate resource cost allocations for resources in the Upper Midwest system. Further, Staff was interested in pursuing the Company's proposal to institute a formal resource planning process in the state, in order to provide the North Dakota Commission with more information about planned resource additions earlier in the process, and to provide the Company more certainty regarding the state's policy objectives and deemed customer needs.

While we do not see proxy pricing as a viable forward-looking solution for reconciling resource treatment, we continue to believe that instituting a formal resource planning process is beneficial and will provide more clarity to the Commission and the Company on what resources may work as system resources. In response to the Commission's request for a more detailed proposal, we submitted a framework outlining essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion, and a proposed timeline for filing that is consistent with the Minnesota process. We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year, where the Commission confirmed that it is interested in a more formalized resource planning process.

Currently, we do not recover the full PPA costs of the Aurora, Marshall, and North Star solar PPAs, the Community Based Energy Development (C-BED) PPAs, or the Renewable Development Fund (RDF) PPAs from our North Dakota customers.

3. South Dakota

We have also faced challenges in recovering the costs of certain resources in South Dakota. In December 2016, the South Dakota Public Utilities Commission (SDPUC) suspended the fuel clause adjustment in order to investigate the costs of certain disputed resources recovered through the fuel clause.[22] The Company worked with South Dakota Commission Staff to development a Settlement to address these concerns. In September 2017, the Commission approved a Settlement Stipulation that addressed the costs recovery for the Aurora solar resource and several biomass resources. The Settlement also required the development of proxy prices for several remaining disputed resources, which include the Marshall and North Star solar PPAs, C-BED PPAs, and Renewable Development Fund PPAs. The Company submitted a proxy price proposal to the South Dakota Commission which provided eight potential proxy pricing options for the Commission's consideration and recommends a combination of market-based and index-based pricing, depending on the particular resource.[23] We are engaging in ongoing discussions with South Dakota Staff as we work toward a resolution of these outstanding issues. While we are working to develop proxy prices as a resolution for past resources, when disputes arise in the future we would work to develop a cost allocation mechanism to allocate the costs and benefits of new resources to the participating jurisdictions.

Currently, we do not recover the full PPA costs of the Aurora solar project from our South Dakota customers and we are recovering the costs of the PPAs for the disputed resource subject to refund based on the resolution of the proxy price proceeding.

4. Wisconsin

In Wisconsin, the Company is subject to a Renewable Portfolio Standard (RPS) equal to 12.89 percent of its three-year average in-state retail energy sales. In 2018, excluding renewable energy used for voluntary renewable programs, NSPW provided 24.3 percent of its retail energy sales from RPS-eligible renewable-based energy sources, and the Company is in compliance with its 2018 RPS requirements.[24] This requirement has not changed recently. However, the state's newly elected governor has identified climate objectives as one focus of his administration. In line with these goals, the administration has proposed carbon reduction goals for the state's electric sector that are broadly consistent with our objectives to reduce emissions by 80 percent from 2005 levels by 2030, and 100 percent by 2050. It is not yet clear

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[22] *See* South Dakota Docket No. EL16-037.
[23] *See* South Dakota Docket No. EL18-004.
[24] *See* Docket 5-RF-2018 *Renewable Portfolio Compliance Plan for CY 2018. Northern States Power Company, a Wisconsin Corporation.*

whether these proposed goals will result in additional mandates for the electric sector.

5. Michigan

In Michigan, the Company is subject to a Renewable Energy Standard (RES) equal to 15 percent of retail sales by 2021, with a goal of 35 percent renewables and 25 percent energy waste reduction by 2025. We are ahead of schedule on both these goals, already exceeding the 2021 RES requirements and expecting to meet the 2025 goals by 2020.

This year will also be the first time we are required to submit a Resource Plan to the Michigan Public Service Commission, in accordance with Public Act 341 of 2016. Michigan's new Resource Plan process allows us to file the same resource plan in Michigan as we are filing with the Minnesota Commission, and on a similar timeframe, with the understanding that the Michigan Commission may ask for additional supplemental information to help them evaluate the plan as it relates to Michigan.[25] We plan to file this multi-state Resource Plan in Michigan on July 31.

H. Conclusion

We believe our progressive carbon reduction goals are the right path forward for the our customers, our employees, our Company and the State. We are confident in our ability to achieve these goals while maintaining the reliability and affordability our customers count on. This transition, while exciting, is not without challenges. We will continue to navigate significant market and regulatory uncertainty, jurisdictional differences, technology changes and more. That said, we are optimistic that these challenges also present opportunities to engage with customers, regulators, market operators, communities, and employees on our goals in a way that meets multiple stakeholders' objectives.

[25] *See* U-15896/U-18461 at 11.

CHAPTER 3
MINIMUM SYSTEM NEEDS

Our resource planning process focuses on deep carbon reductions while serving our Upper Midwest customers reliably and affordably. In this Chapter, we describe in more detail how we arrived at the minimum amount of resources our system will need through the planning period. The system needs and existing resources evaluated here formulate the baseline upon which we have developed the Reference Case, our modeling scenarios, and ultimately our Preferred Plan.

We have made the following changes to aspects of our Minimum System Needs approach with this Resource Plan:

- *Supply-side Resource Treatment for DSM.* In this Resource Plan we are treating both EE and DR as supply-side resources, rather our previous treatment of EE as an adjustments to future load. Supply-side resources available to the model now include incremental EE and DR in "bundles," or amounts of achievement that we formed from the *Minnesota Energy Efficiency Potential Study* and *Brattle Demand Response Potential Study*, respectively.
- *Reliability Requirement.* We have developed and applied a threshold requirement for firm dispatchable resources. This Requirement is needed to ensure system reliability and resilience until MISO evolves its capacity accreditation construct to better recognize the variability and declining incremental electric load carrying capability of wind and solar resources.

I. MEETING CUSTOMER NEEDS

Forecasting customers' needs for electricity is a key component of any resource plan, and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. The first step is forecasting the amount of electricity our customers will need over the planning period. To this, we add a reserve margin that is prescribed by MISO. We then subtract the resources we already have or expect to have (with some adjustments), to determine our net surplus or need.

We illustrate this concept and discuss each of the components below.

Figure 3-1: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

A. Customer Needs Forecast

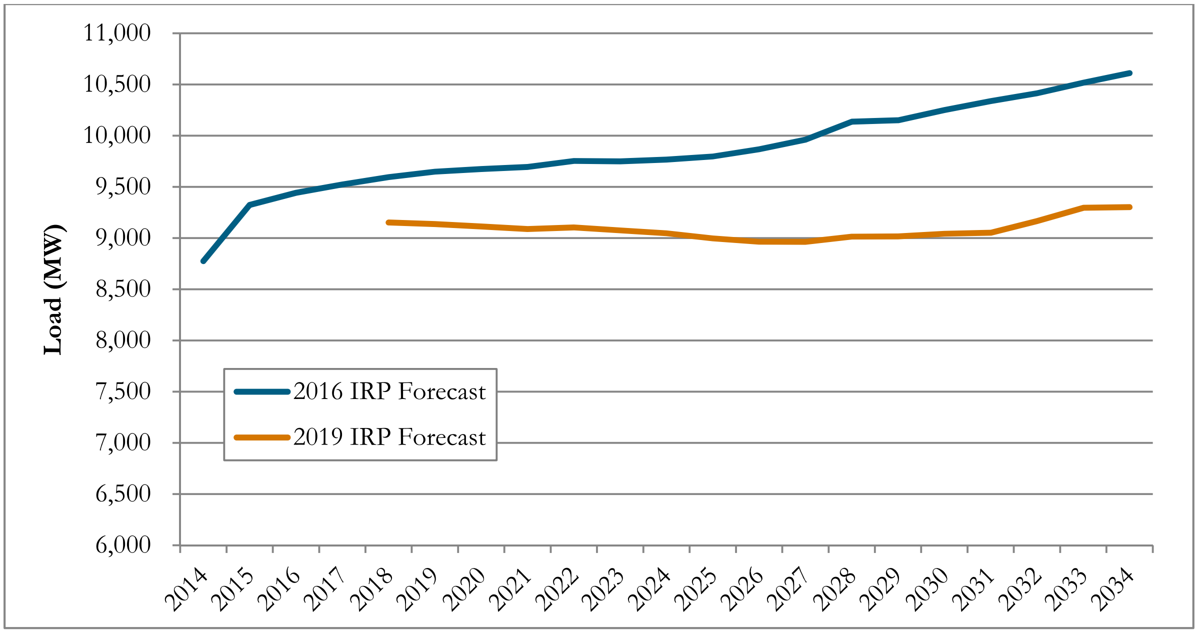
Forecasting our customers' energy needs starts with a capacity, or peak demand, assessment, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

1. *Peak Demand Requirements*

We use econometric analysis and historical actual coincident net peak demand data to determine system capacity requirements for each year. We provide a detailed discussion about our peak demand forecasting methodology in Appendix F1.

Our current forecast shows essentially flat load relative to current levels, with an average annual growth rate of less than 0.2 percent, after accounting for EE. Figure 3-2 below shows the current forecast in relation to the forecast from our last Resource Plan.

Figure 3-2: Forecasted Peak Load, After Energy Efficiency Adjustments (MW)[1]



We have changed our approach to how we present our peak forecast from our last Resource Plan based on our treatment of EE as a supply-side resource in this Plan. The peak forecast in our previous Resource Plan included both a demand reduction associated with historic EE, as well as from the impact of future incremental EE as approved in the previous Resource Plan.

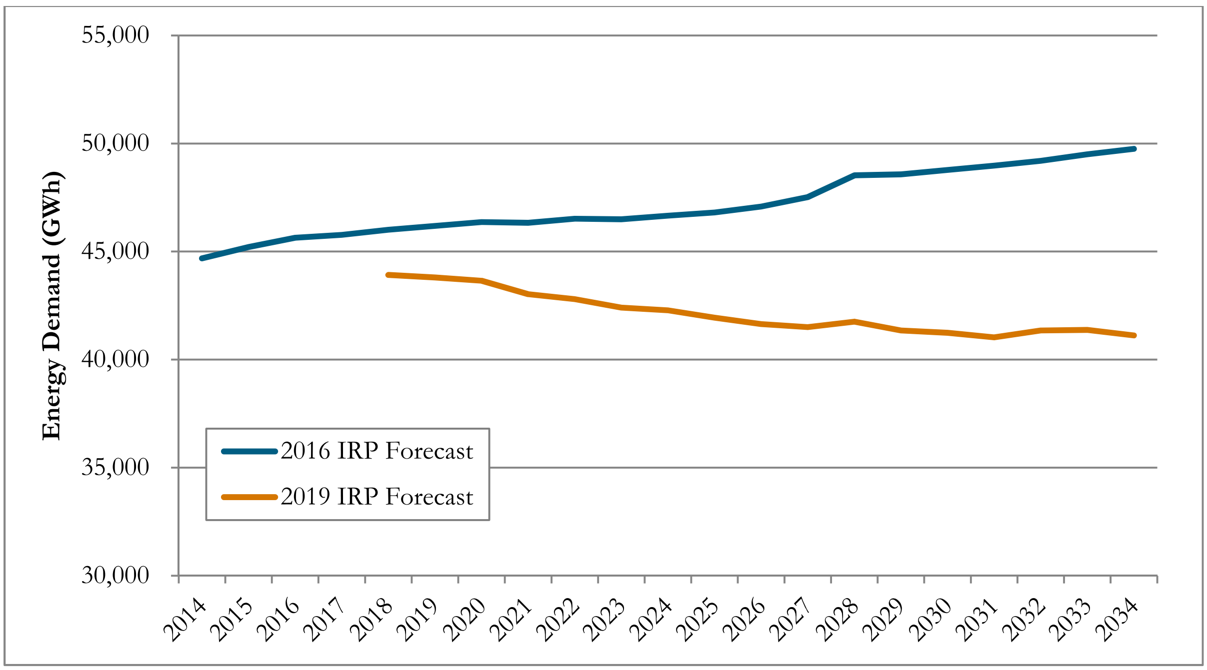
For this Resource Plan, we have changed our approach to addressing EE in two ways. First, the load forecast used in our Strategist modeling no longer has embedded incremental EE, although it is shown in that manner in the charts above for comparison purposes with previous Resource Plans. Instead, we treat EE as a supply-side option that the Strategist model can select in its resource optimization. To do so, we developed EE "Bundles," which we describe in Part III below and in more detail in the Strategist Assumptions Appendix F2. As a result, rather than adjust our peak forecast based on an assumed level of future EE adoption (this would have been 1.5 percent per the level approved in our last Resource Plan), we are reflecting our commitment to *higher* levels of EE achievement (approximately 2.5 percent reduction) in our Reference Case. This level of EE reflected in the Reference Case is representative of two of the EE Bundles available for Strategist to select.

[1] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a load reduction from gross load for purposes of the chart above.

2. *Energy Requirements*

We forecast declining energy needs of approximately 0.4 percent over the 2020-2034 planning period, after accounting for EE included in the Reference Case. As discussed above, the inclusion of two incremental EE Bundles reflects achievement of approximately 2.5 percent EE, which leaves our Net Demand substantially lower than forecast in our last Resource Plan. Figure 3-3 below compares our estimated net energy demand adjusted by the two EE Bundles, to the energy forecast in our last Resource Plan.

Figure 3-3: Forecasted Net Energy Requirements, After Energy Efficiency Adjustments[2] (GWh)



3. *Forecast Adjustments*

After determining the base peak capacity and energy demand forecasts, we make certain forecast adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. We summarize our key adjustments below:

DSM. In past Resource Plans, the load forecasts used by Strategist were adjusted for

[2] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a demand reduction from gross demand for purposes of the chart above.

the expected effects of existing DSM programs. In this Resource Plan, based on feedback from stakeholders, incremental EE is no longer embedded in the load forecast, rather EE is treated as potential supply-side resource in our modeling, like DR. Both EE and DR are shown as separate line items in our Loads and Resources table below, though in an effort to maintain consistency with Load and Resource reporting between this and previous Resource Plans, we show EE "above the line" as a subtraction from gross load. We further discuss the EE and DR (collectively, DSM) in the context of our resource planning process in Appendix G1.

Distributed and Small Scale Customer Solar Generation. We have historically considered customer adoption of distributed solar (i.e. DG solar as well as CSG) installations as a modification to load in the resource planning process. In this Resource Plan, we have accounted for DG solar including CSG resources as a supply-side resource with assumed adoption levels, as shown in the Loads and Resources calculation below. Reference Case assumptions currently take into account interconnection requests and expectations based on policy-driven programs. However, we also conduct sensitivity testing around potential increased levels of adoption and are working to develop new tools that improve our understanding of how key market drivers will affect customer distributed solar adoption going forward. We note that our methods for projecting distributed solar installations are currently evolving. As our tools and methods mature, we will increasingly incorporate them into both our Resource Plan and IDP processes.

Expected Customer Changes. We also make adjustments to account for known changes in load on our system. These typically reflect expected changes in specific large customers' electricity usage, either as a result of increased behind the meter energy generation (decreasing demand) or increased production activities (increasing demand).

Light Duty Electric Vehicle Adoption. We adjust our residential energy and peak demand forecasts to account for increasing use of plug-in electric vehicle charging. These forecasts are based on expectations around current stock and future adoption (including the effect of financial incentives to facilitate adoption), and the expected electricity consumption per vehicle.

We use standard statistical modeling techniques to reflect these and other potential sources of variation around our expected forecasts. We discuss our forecasting process, inputs, assumptions, adjustments and results in more detail in Appendix F1: Load and Distributed Energy Resource Forecasting.

II. MISO RESOURCE ADEQUACY REQUIREMENTS

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSE) like the Company to maintain resources that exceed their level of demand by a specific margin (planning reserve margin or PRM) to cover potential uncertainty in the availability of resources or level of demand.[3] The RA requirements are fundamental to the resource planning process, and inform the level of capacity we need in our portfolio to adequately serve customers over a long-term planning process. We describe the various aspects of the calculation below, and note that our effective reserve margin is 2.98 percent.

MISO's RA requirements are set based on an annual planning period; the 2018/2019 planning period covers June 1, 2018 through May 31, 2019. Prior to each planning year, MISO determines two different capacity obligations for each LSE; one for the entire MISO footprint as a whole, and one for the Local Resource Zone (LRZ or Zone) where the LSE resides.[4] For any particular planning year, an LSE's PRM is the greater of the LSE's capacity obligation for the MISO footprint or its capacity obligation for its LRZ.

A. MISO Footprint Capacity Obligation

By November 1 prior to a planning period, MISO issues the finalized PRM applicable to all LSEs within its footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM needed to achieve a Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2018 through May 31, 2019 the overall MISO PRM was 17.1 percent on an installed capacity (ICAP)[5] basis and 8.4 percent on an unforced capacity rating (UCAP) basis.[6] The study also provides

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[3] The factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

[4] Almost all of the NSP system load is located within LRZ 1, which includes almost all of Minnesota, western Wisconsin, and the Dakotas. Approximately 7 MW of load along the Minnesota-Iowa border is located in LRZ 3.

[5] ICAP refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.

[6] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "Planning Year 2018-2019 Loss of Load Expectation Study Report" at 5. Available at: https://www.misoenergy.org/api/documents/getbymediaid/80578

forward-looking PRM values, through 2028. Over the planning period MISO examined in the 2018-2019 LOLE study, the UCAP PRM remained relatively constant between 8.3-8.4 percent.

Each LSE is required to have resources sufficient to meet the forecasted demand at the time of MISO's peak demand, plus its PRM margin. MISO's tariff acknowledges a state regulatory body's authority to establish a PRM for LSEs within its jurisdiction, which would override the PRM otherwise determined by MISO. None of the NSP System states have established a PRM separate from MISO.

B. Zonal Capacity Obligation

Additionally, MISO makes an annual determination regarding the amount of capacity required within each of MISO's Zones, called the Local Clearing Requirement (LCR). The LCR is determined as a function of each Zone's Local Reliability Requirement (LRR) and its Capacity Import Limit (CIL). The LRR represents the necessary resource requirement in order for a Zone to achieve an LOLE of 0.1 day per year, without relying on resources outside of the Zone. Each Zone, having a smaller footprint than the overall MISO footprint does not benefit from the same level of peak load diversity as does the larger, more diverse MISO footprint. Thus, it can be expected that a Zone's LLR is greater than the sum of its LSEs' MISO footprint obligations. If a Zone within which an LSE operates has import capacity, however, the resulting LCR is reduced. As a result, LSEs usually plan their minimum system needs based on the MISO-wide PRM rather than the zonal requirement.

For the 2018-2019 planning year, Zone 1 was assigned an LRR of 114.8 percent, which, in capacity terms equates to an LRR of 20.2 GW. However, when accounting for Zone 1's CIL of 4.4 GW, Zone 1's LCR is 15.8 GW. This is less than the MISO footprint PRM of 18.4 GW. Thus, Zone 1's import capabilities allow LSEs within Zone 1, including the Company, to plan to the MISO-wide UCAP PRM of 8.4 percent rather than the higher LRR value.

C. Capacity Obligations Derived From Forecasted Demands

After determining the relevant PRM, each LSE can derive its MISO-wide and zonal capacity obligation from its forecast of peak demand (peak load). While LSEs typically forecast the peak demand for their individual system, the resource adequacy process requires the LSE to also forecast:

- The LSE's demand at the time of the MISO footprint's peak demand (MISO Coincident Peak Demand, or MISO CPD), and

- The LSE's demand at the time of the LRZ's peak demand (Zonal Coincident Peak Demand, or Zonal CPD).

Again, because each LRZ footprint is smaller than the MISO footprint, the LRZ's load diversity is lower than the load diversity of the MISO system, and an LSE's Zonal CPD is equal to or greater than its MISO CPD.

The NSP System CPD factor measures how closely our system peak matches the MISO system peak. A coincidence factor of 95 percent indicates that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. In other words, the timing of our peak and the MISO peak does not match exactly, so we are able to reduce the amount of reserves we carry as a result. After accounting for the coincidence factor, our effective reserve margin drops from 8.4 percent to 2.98 percent. We illustrate this calculation in Figure 3-4 below.

Figure 3-4: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2018 to May 31, 2019

$$(95\,percent\ coincidence\ factor)x\ (1 + 8.4\,percent) - 1 = 2.98\,percent\ effective\ reserve\ margin\ for\ NSP$$

Putting these pieces together, we used our effective reserve margin, in combination with our annual load forecasts over the planning period, to determine our overall capacity obligation for the same period. For 2020, this calculation results in the following approximate obligation:

Table 3-1: Capacity Obligation Calculation – 2020 Example

Total Capacity Obligation Component	Value
Forecasted load	9.1 GW
NSP Effective Reserve Margin	x (1+ 2.98%)
NSP Obligation	**= 9.4 GW**

Our estimated obligation for all planning period years can be found in the Load and Resources table in Section VI. below.

D. Capacity Accreditation of Resources

After these obligation levels have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements. While there are different requirements among the various types of resources, common characteristics require resources participate in the annual registration process, requiring annual testing and reporting of capability or reporting of historical output. Each resource must have firm delivery to load, and resources must be available throughout the entire planning period.

Resources used to achieve MISO's RA requirements are referred to as "Planning Resources." Planning Resources include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO's resource accreditation represents a measure of a resource's reliable contribution to the system's resource adequacy needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating recognized as an accredited resource. Therefore, instead of using installed or nameplate capacity (i.e. ICAP), MISO calculates the unforced capacity value (i.e. UCAP) for each resource to determine its expected contribution to RA. These are calculated differently depending on the resource's dispatchability or variability:

- *Dispatchable generation resources, DR and EE* – MISO assigns a UCAP value for dispatchable generation resources by discounting their installed capacity by an anticipated forced outage rate. Resources where availability depends on other factors are measured differently; for example, MISO has a process to determine the UCAP for DR resources using a documented process of assessing the resource's observed responsiveness and load reduction effectiveness.
- *Variable resources* – MISO assigns variable resources, such as grid-scale solar and wind, a UCAP value that is a function of the individual unit's historical performance during the peak hours of the planning period. Currently, these units are measured on historical performance during the operating hours of

1500 to 1700 in the months of June-August over the three most recent summers. Each site must have one complete historic period of data prior to unit accreditation. If sufficient operating history is not available, MISO assigns a proxy value.

Our modeling selects resources based on their UCAP values, to ensure we maintain adequate capacity on our system over the planning period. Additionally, as discussed below in Section IV, we included a further Reliability Requirement in our planning process to address MISO's evolving processes.

III. DEMAND SIDE MANAGEMENT

DSM programs offer our customers opportunities to lower their energy use and manage their peak demand, in particular through our Conservation Improvement Programs. As noted previously, these programs include both EE and DR. We base our forecasts and potential incremental additions on historic achievements through our programs, as well as external studies about expected and potentially achievable adoption rates.

As previously discussed, we adjusted the customer capacity and energy forecasts in this Resource Plan to distinguish incremental EE from the load forecast. We modeled incremental DR and EE achievements as "Bundles" to be evaluated alongside other resource options. Each Bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost.

For EE, these Bundles include measures that work to reduce a customer's overall energy usage throughout the year. The DR Bundles, on the other hand, reflect a customer's commitment to discrete reductions in demand (e.g. on a day when peak load is expected to be high otherwise). These actions are expected to reduce the anticipated annual system peak demand, as well as smooth demand on specific days when weather or other conditions lead to high demand at a certain point in time. In the Order approving our last Resource Plan,[7] the Commission directed that the Company "shall acquire no less than 400 MW of additional DR by 2023." In this Resource Plan, we included one DR Bundle in our modeling for both the Reference Case and Preferred Plan.

We discuss the studies that informed our expected EE and DR levels, our analysis,

[7] *See* E002/RP-15-21 Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (January 11, 2017), Order Point 10.

and the changing DSM landscape in more detail in Appendix G1.

IV. RELIABILITY REQUIREMENT

A new planning element we included in this Resource Plan is a Reliability Requirement which, in short, will ensure that we can serve customers with reliable energy every hour of every day.

The need for the Reliability Requirement stems from the inherently variable nature of renewable resources and availability of any time limited resource. Further, as the penetration of these resources increases, their value to meet peak customer needs decreases. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. Until MISO determines how best to address these gaps, we believe it is incumbent on us as the utility to take steps to ensure that our system is resilient and that our customers will be reliably served. Fundamentally, we have a responsibility to ensure we have access to a sufficient level of firm dispatchable resources in all grid conditions that can flexibly adapt to variable renewable resource performance to meet our customers' needs.

To develop the Requirement, we analyzed industry insights and data from case studies, including the 2019 polar vortex and normal winter and summer days. From this information, we developed a method determine a threshold level of firm dispatchable resources needed to serve customer loads, that reflects a reasonable level of reliance on MISO resources and DR to meet a portion of the need.

Figure 3-5 below demonstrates the calculation of the Reliability Requirement we applied in our modeling for this Plan.

Figure 3-5: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6.4 GW
Minus Firm DR (Winter) Proxy – (0.2) GW
Minus Firm Market Supply Proxy – (0.5) GW

Reliability Requirement - 5.7 GW
(Firm dispatchable resources)

To implement this Requirement, we applied it as a threshold in our Strategist modeling to ensure that our firm dispatchable resources do not fall below this level – even while our Preferred Plan achieves an 80 percent carbon reduction by 2030. In the 2020-2034 planning period, the Requirement ranges from approximately 5.6 GW early in the planning period, to about 6.0 GW by the end of the planning period. We clarify here, however, that while this concept is essential to include until MISO evolves its capacity accreditation constructs, the Requirement as applied in our modeling has little effect for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until near the end of the planning period, in 2031. This long runway leaves ample time for MISO and its stakeholders to address this aspect of its planning and provide additional direction.

V. EXISTING RESOURCES

Our current generating resources[8] comprise a diverse portfolio including nuclear, coal, wind, biomass, solar, hydro, natural gas and oil-fueled facilities. Physical generating assets owned by the Company have a net maximum capacity of over 9,500 MW, including 850 MW of wind.[9] In addition to these assets, we maintain PPAs representing a net maximum capacity of over 3,700 MW.[10] Together, these provide over 13,200 MW of generation resources, of which over 4,300 MW[11] is supplied by renewables. A total of over 6,000 MW[12] is supplied by carbon-free resources.

A. Renewable Resources

In total, we currently have over 4,300 MW of renewable capacity serving the NSP System, including:[13]

- Over 2,600 MW of wind
- 840 MW of solar, including community solar programs and grid-scale solar[14]
- 680 MW of hydroelectric power[15]
- 160 MW of biomass and landfill gas

[8] As of July 2019; excludes some resources included in modeling that are expected to be online by the end of 2019.
[9] Maximum capacity represented here reflects capacities included in Strategist modeling. It approximates Net Maximum Capacity, which is defined as the units Gross Maximum Capacity, less any capacity that is used for that unit's station service or auxiliary load.
[10] This total excludes 425 MW of renewable diversity capacity credit from contracts with Manitoba Hydro.
[11] *Id.*
[12] *Id.*
[13] Note: these values are approximate.
[14] Per Docket No. E002/RP-15-21 Order Point 4a (January 11, 2017), our solar acquisitions will exceed the 650 MW through CSG resources or other cost-effective acquisitions. The CSG program is on track to exceed the ordered 650 MW by year ending 2019, per the most recent forecast CSG Monthly Report (filed June 14, 2019) and included in this filing as Appendix N8.
[15] Excluding capacity associated with diversity agreement contracts with Manitoba Hydro.

B. Nuclear

Our Monticello and Prairie Island nuclear plants provide nearly 1,740 MW of clean energy and capacity to our customers and play an important role in achieving our goal of an 80 percent reduction in system carbon emissions by 2030, while maintaining reliability and affordability. The monthly capacity factors of our nuclear facilities are historically 90 percent or higher. Together, our nuclear plants currently provide nearly 30 percent of our energy mix. In terms of production costs (fuel plus O&M), both plants have achieved reductions of more than 20 percent since 2015, with average costs now below $30/MWh.

C. Coal

Our coal fleet includes our Sherco Units 1, 2, and 3 in Becker, Minnesota and the Allen S. King plant in Oak Park Heights, Minnesota. This coal fleet provides almost 2,400 MW of baseload and cycling generating capacity, and supports system reliability. In our last Resource Plan, the Commission approved our proposal to retire Sherco Units 1 and 2 in 2026 and 2023, respectively. These retirements are reflected in our Reference Case discussed below. Our Preferred Plan further proposes to retire the King plant in 2028 and Sherco 3 in 2030, after which coal would no longer be part of our energy mix.

D. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of both intermediate and peaking generation. We have five owned or contracted intermediate-type generating assets that provide just over 2,400 MW of capacity. We have peaking-type resources located at seven sites, providing another 2,350 MW of capacity. Combined, these facilities provide valuable load following capabilities for our system, cycling as necessary to provide important flexibility to our generation operations and support to our growing renewable resources. Our Reference Case also includes pending and proposed capacity resource additions including MEC as proposed in Docket No. IP6949,E002/PA-18-702, and the Sherco CC that the Commission acknowledged in its Order in our last Resource Plan.[16] These pending resources appear in separate line items in our net resource calculation below.

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[16] The Commission approved our proposed schedule to retire Sherco Units 1 and 2, and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026. *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point Nos. 7 and 8, Docket No. E002/RP-15-21 (January 11, 2017).

VI. NET RESOURCE SURPLUS/DEFICIT

As described above, our forecast of customers' peak demand and MISO Resource Adequacy requirements are used to determine our overall total generating capacity obligation. From this, we deduct our expected load management achievements and UCAP generating capacity of the various resources we have included in our Reference Case to determine our net generation capacity surplus or deficit. We anticipate a net surplus through 2026 and a deficit thereafter.

Table 3-2: Reference Case Load and Resources,[17] 2020-2034 Planning Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load	10,499	10,559	10,621	10,684	10,755	10,820	10,886	10,954	11,140	11,232	11,320	11,418	11,518	11,619	11,717
Forecasted EE[18] (reduction to load)*	(1,386)	(1,472)	(1,517)	(1,609)	(1,707)	(1,822)	(1,921)	(1,992)	(2,125)	(2,215)	(2,278)	(2,366)	(2,352)	(2,324)	(2,415)
Forecasted net load	**9,112**	**9,087**	**9,103**	**9,075**	**9,048**	**8,998**	**8,965**	**8,963**	**9,014**	**9,016**	**9,042**	**9,052**	**9,166**	**9,295**	**9,301**
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,657	8,633	8,648	8,621	8,595	8,548	8,517	8,514	8,564	8,565	8,590	8,599	8,708	8,831	8,836
MISO PRM	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
NSP Obligation	**9,384**	**9,358**	**9,374**	**9,345**	**9,317**	**9,266**	**9,232**	**9,230**	**9,283**	**9,285**	**9,312**	**9,321**	**9,439**	**9,572**	**9,579**
Reference Case resources (UCAP)															
Load Management *(existing)*	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management* *(potential study)*	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,390	2,390	2,390	2,390	1,699	1,699	1,699	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017
Nuclear	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	992	992	992	484
Natural Gas/Oil	3,295	3,295	3,295	3,295	3,141	2,829	2,624	2,136	2,018	2,018	2,018	2,018	1,765	1,765	1,765
MEC*	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sherco CC*	0	0	0	0	0	0	0	727	727	727	727	727	727	727	727
Biomass/RDF	110	110	110	86	86	63	63	63	22	22	22	22	22	22	22
Hydro	877	997	989	989	989	162	162	162	162	162	162	162	156	152	152
Wind	596	650	696	670	659	642	637	622	616	594	593	578	575	511	492
Grid-scale solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Solar*Rewards Community Solar	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Existing Resources	**11,267**	**11,486**	**11,571**	**11,559**	**10,746**	**9,634**	**9,460**	**9,040**	**8,913**	**8,905**	**8,920**	**8,311**	**8,066**	**8,026**	**7,521**
Net Resource (Need)/Surplus	**1,884**	**2,128**	**2,196**	**2,213**	**1,429**	**368**	**228**	**(190)**	**(370)**	**(380)**	**(392)**	**(1,010)**	**(1,373)**	**(1,546)**	**(2,058)**

While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a Certificate of Need. *See* Laws of Minnesota 2017, chapter 5 – H.F. No. 113, section 1.

[17] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case.

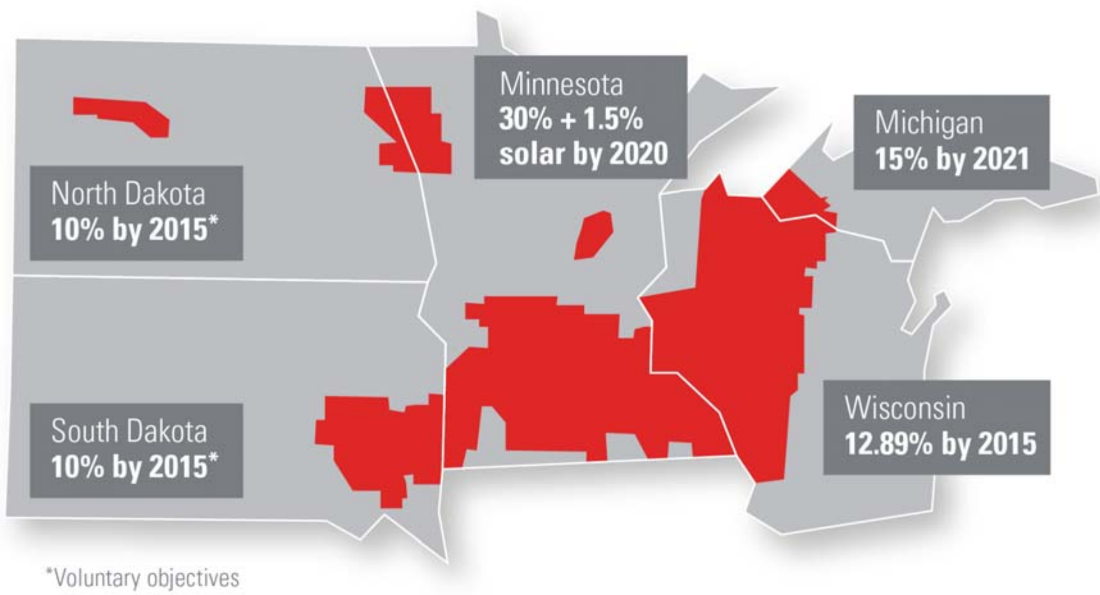
[18] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels. Also includes minimal EV and coincidence adjustments.

VII. MEETING RENEWABLE ENERGY REQUIREMENTS AND GOALS

A. Minimum Compliance Requirements

Each of the states in the NSP System has a different public policy with respect to renewable energy requirements or objectives. Figure 3-6 below illustrates each state's renewable energy standard (RES).

Figure 3-6: Renewable Energy Requirements and Objectives – NSP System



Three of our states have renewable standards expressed as a percentage of electric retail sales from qualifying resources by a certain date. Minnesota's RES is the highest, requiring that 30 percent of the Company's energy come from renewables, with at least 24 percent of the electricity we provide to retail customers coming from wind energy by 2020[19] Legislation passed in the 2013 session also established a Solar Energy Standard (SES) for Minnesota that requires that investor-owned utilities in the state generate 1.5 percent of 2020 retail sales, net of customer exclusions, from solar energy resources. Of that 1.5 percent, 10 percent must come from systems with

[19] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards an overall 25 percent wind and solar requirement (amounting to 1% of total sales). The SES is assessed separately. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691.

capacity less than 40 kW.[20] The legislation also established a goal of 10 percent of energy sales from solar by 2030.

North Dakota and South Dakota each have a voluntary objective that includes renewable or recycled energy.[21] Further, our North Dakota regulators have indicated that compliance with the North Dakota Renewable Energy Objective should be accomplished with competitively-priced energy.

To-date we have implemented a strategy to have the entire NSP System comply with, at the very least, the highest of renewable energy requirements across our jurisdictions; in this case, the Minnesota RES. This strategy also places us in compliance with the specific requirements in each of our other jurisdictions. As a result, we have been planning for renewable energy additions, and allocating their benefits, to all of our jurisdictions (with certain exceptions as discussed in the Planning Landscape). As state energy policies continue to evolve, however, we will continue to examine whether this requires a strategy change going forward, and engage our Commissions as needed on that topic.

B. RES Compliance

Given existing and previously approved resources, we project continued compliance with the renewable energy goals and standards in each of our NSP states. The Company currently maintains a set of banked Renewable Energy Credits (RECs) for future compliance.[22] In the past, we have leveraged our REC bank to manage the size, type, and timing of renewable energy additions on our system, to ensure that we identify and acquire the renewable generation resources that provide our customers with the greatest value at the lowest cost. Given our recent focus on adding renewable capacity, however, we now generate RECs in excess of our baseline obligations each year. We currently generate sufficient RECs annually from eligible renewable resources to account for over 40 percent of the energy we provide our NSP System customers, which outpaces our annual requirement

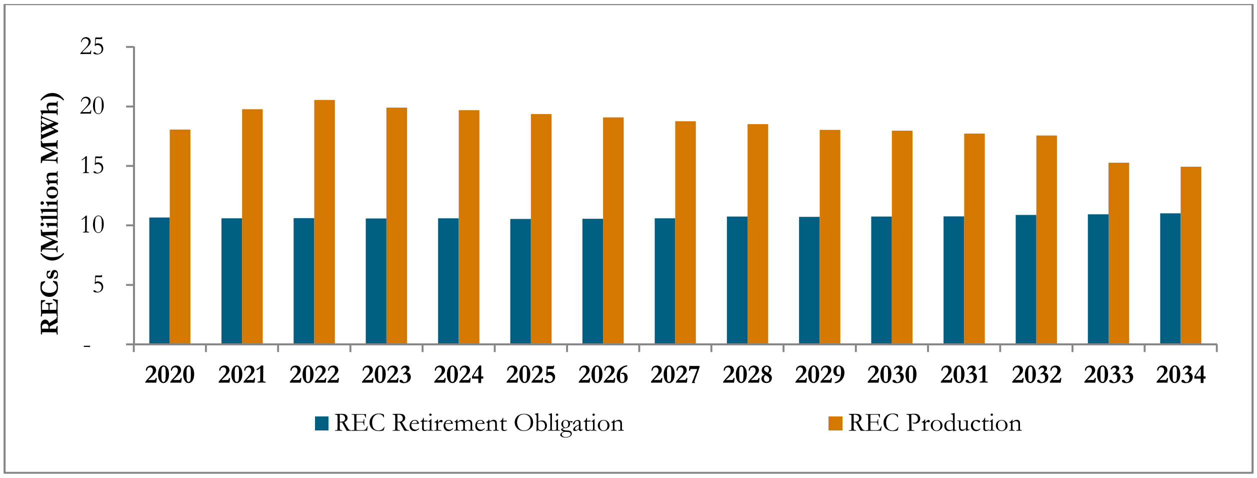
[20] The original legislation set a threshold of 20 kW, but was increased to 40 kW in 2018, per HF3232. *See* "Minnesota Renewable energy Standard: Utility Compliance." Minnesota Department of Commerce (January 2019) at 7. Available at: https://www.leg.state.mn.us/docs/2019/mandated/190330.pdf

[21] 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.

[22] A REC is an accounting device designed to reflect the renewable energy attributes of a particular MWh of renewable energy generation. RECs are the currency for compliance with state renewable targets.

Figure 3-7 below illustrates annually generated RECs across the NSP System in the Reference Case scenario. In this scenario, we will have sufficient RECs to comply with the current renewable energy goals and standards of all of our NSP jurisdictions through 2034, even without securing additional renewable resources.

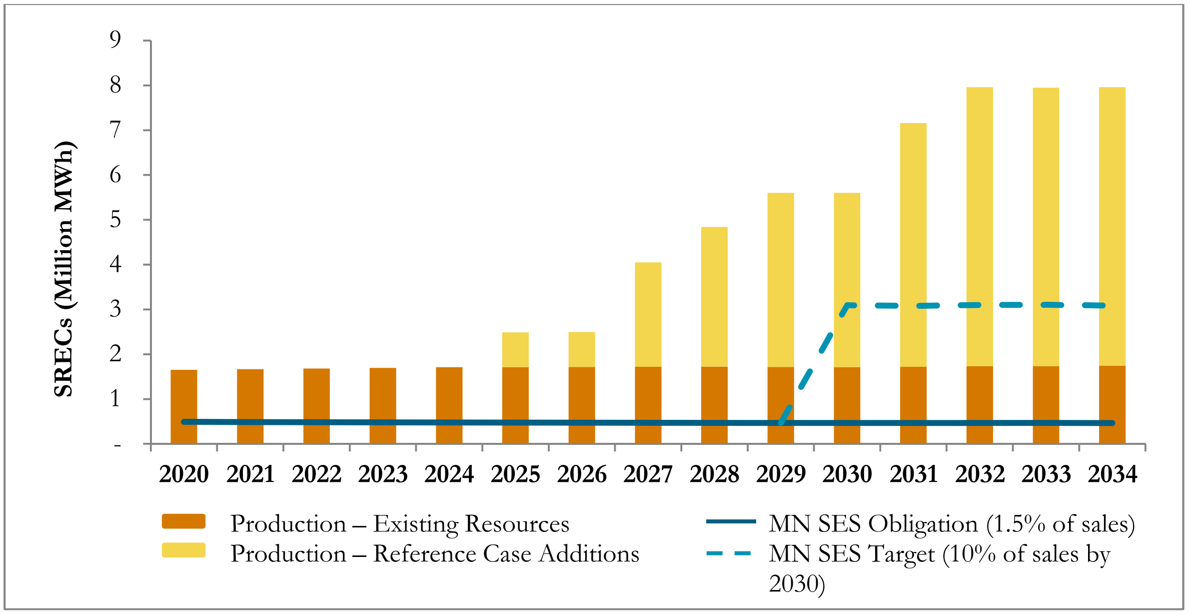
Figure 3-7: REC Production and Retirement Obligations for NSP System – Existing Resources Only



C. SES Compliance

As previously mentioned, Minnesota law requires us to provide our customers with solar-generated energy equal to at least 1.5 percent of our annual customer demand by 2020, and a goal of 10 percent by 2030. We have developed a portfolio of programs to provide solar options to residential and commercial customers, and have also grown our utility-scale solar profile. As a result, we expect to meet the SES requirements through the planning period, per our Reference Case. We also expect the solar capacity additions included in our Reference Case to provide sufficient energy to meet the 10 percent goal by 2030. Figure 3-8 below demonstrates our annual estimated SREC production relative to Minnesota requirements and goals, for the Reference Case scenario.

Figure 3-8: NSP System SREC Production and Minnesota Annual Requirements



We discuss our renewable energy standard compliance further in Appendix N4: Renewable Energy Compliance Positions.

VIII. ENERGY POLICY AND COMPANY GOALS

As demonstrated, we believe that we are well positioned to meet minimum system needs. At least through 2024, we expect that we will be able to meet those needs with existing and already-approved resources. However, in 2018, we committed to an ambitious carbon reduction vision, to achieve 80 percent below 2005 carbon emissions levels by 2030 and 100 percent carbon-free energy by 2050. We are committed to achieving this goal, and as such, have modeled our Reference Case, Preferred Plan, and all other scenarios using our 80 percent carbon reduction target as a guidepost.

IX. REFERENCE CASE

We incorporate all of the aforementioned elements into the Strategist modeling tool, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analysis by individually changing key assumptions and re-running the plans under these changed assumptions. Our analysis resulted in the following Reference Case Expansion Plan, depicted in Tables 3-3 and 3-4 below:

Table 3-3: Reference Case Annual Expansion Plan (UCAP)[23]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	250	0	500	250	250	0	500	250	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	727	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	206	330	330
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	20	7	11	10	11	2	17	2	9	5	82	247
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**184**	**188**	**468**	**196**	**1,453**	**442**	**443**	**179**	**685**	**630**	**579**	**745**

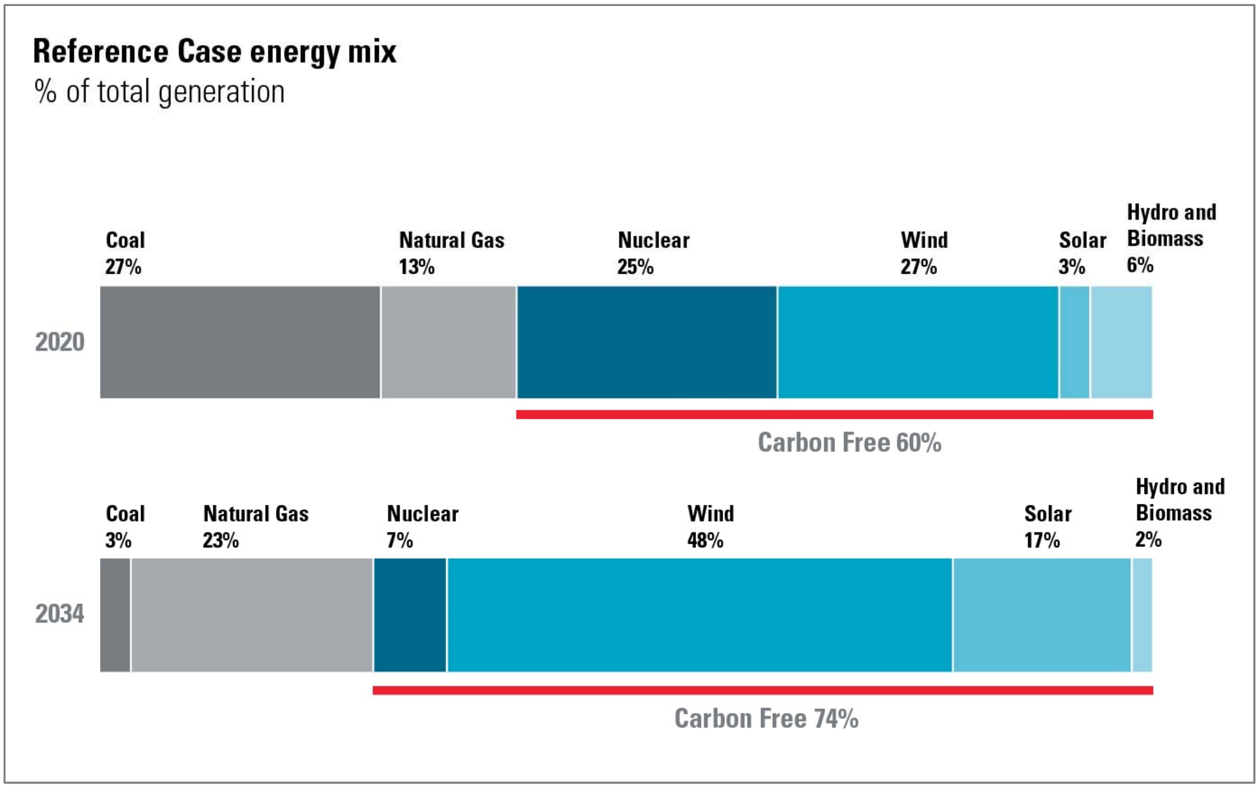
Table 3-4: Reference Case Annual Expansion Plan (ICAP)[24]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	0	1000	500	500	0	1000	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	232	374	374
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	1581
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	540	172	159	290	226	777	252	2,098	700	784	193	1,232	932	1,065	2,123

The Reference Case presented here would result in the following energy mix:

[23] Note: This table includes CC, EE, DR, and Distributed Solar resources that are also reflected in the Load and Resources Table.
[24] Note: This table shows ICAP values of the resources indicated in Table 3-4 above.

Figure 3-9: Reference Case Energy Mix in 2020 and 2034



We outline and discuss the starting assumptions, scenarios, and sensitivities that formed our Strategist analysis, and resulted in our Preferred Plan, below and in Appendices F2 and F3.

CHAPTER 4
THE PREFERRED PLAN

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. It supports our states' clean energy goals and the Company's goal of reducing carbon emissions 80 percent by 2030 – and our ultimate vision of 100 percent carbon-free energy by 2050.

Key components of our Preferred Plan include:

- Retiring nearly 2,400 MW of remaining coal-fired capacity by 2030, including previously approved Sherco 1 and 2 retirements and newly proposed accelerated retirement timelines for Sherco 3 and King. We also plan to implement seasonal dispatch at Sherco 2 prior to its retirement.
- Adding thousands of megawatts of new renewable resources, including substantial solar additions and replacement of expiring wind PPAs.
- Continuing to operate our nuclear plants at least until the end of their licenses, and extending operation of Monticello to 2040, as these resources anchor the grid in around the clock carbon-free energy.
- Significantly increasing our EE and DR resources, which will reduce our overall system demand.

Maintaining grid reliability and resilience through this transformation – as we must – will require firm and dispatchable load supporting resources and potentially significant transmission development. Accordingly, in order to meet reliability needs and support renewable integration as we retire legacy coal units, our Plan includes continued operation of our nuclear units (including a proposed 10-year extension of Monticello), acquisition of the MEC CC, and construction of a CC at Sherco, which we proposed in our last Resource Plan.

At the same time, we believe there may are exciting opportunities to pilot batteries, DER, and other clean, innovative technologies in the Upper Midwest. With respect to DR, in particular, we are seeking the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies that may go beyond conventional DR.

We have also sought to retain strategic flexibility by deferring decisions on certain generating units such as Prairie Island, which can be addressed in the next planning cycle. Doing so leaves room for innovation and allows for reassessment of technologies, costs, and capabilities before making substantial investments. It is also consistent with our longstanding belief that a deliberate and well-thought-out fleet transition is critical to facilitating successful community and employee transitions.

Finally, our Preferred Plan comes at a reasonable cost to our customers – with estimated rate impacts that are at, or below, the rate of inflation. In other words, we can achieve industry-leading reduction to CO_2 emissions at a cost that is consistent with the expected national average increase in electricity prices.

In summary, the course we have charted in this Preferred Plan drives toward our goal of achieving significant carbon reductions by 2030 and positions us to deliver on our longer term vision of a carbon-free electricity mix by 2050 – all without sacrificing our ability to deliver the reliable and affordable power that our customers count on every day. In this section we discuss: (1) our primary planning objectives and how they are reflected in our Preferred Plan, (2) the key components of the Plan and the actions we intend to take to achieve it, (3) the estimated customer cost impacts of our Preferred Plan, and (4) how this Plan meets the Commission's public interest objectives. We take each in turn.

I. PLANNING OBJECTIVES

When we began this Resource Plan process more than a year ago, we framed key planning objectives that would set the framework for development of our plan. The objectives are complex. They sometimes overlap and conflict, but each played a critical role in guiding our thinking and analysis which ultimately culminated in a plan that achieves substantial environmental benefits, maintains reliability, keeps costs low, and minimizes risks to our customers.

Figure 4-1: Xcel Energy Integrated Resource Plan Objectives

A. Environmental and Innovation

Environmental benefits and the technological innovations that will help us achieve them are front and center in this Resource Plan process. We have made a bold commitment to achieve 80 percent carbon reduction from 2005 levels by 2030, and have considered this target a modeling pillar for all of our potential scenarios. Our Preferred Plan achieves this goal in several ways. First, our Preferred Plan eliminates coal from our system by 2030, extends our carbon-free Monticello nuclear plant to 2040, adds at least 4,000 MW of new renewable resources, including substantial new solar capacity additions, maintains the wind levels committed to in our previous resource plan, and replaces renewables with renewables when they reach the end of their life.

It is important to note that, because many of these resource additions are not needed for a number of years, maintaining flexibility in how we achieve our carbon goals is essential. We have watched the planning landscape evolve at a remarkable rate over the last decade and we expect the rapid pace of innovation to continue. In fact, we expect technological advancements and innovations will create opportunities that we can seize upon in future procurement processes and integrated resource planning cycles if we retain the flexibility to do so. For example, future technology costs and transmission considerations may influence our mix of wind, solar and other non-emitting resources. Likewise, the need for firm and dispatchable load supporting capacity additions beyond 2030 may be better filled by battery storage and other advanced technology solutions. Where appropriate, we aim to be technology agnostic and open to what is coming next.

B. Reliability

Our responsibility to ensure a reliable electricity supply for our customers is a fundamental underpinning of our Preferred Plan. We therefore developed a Reliability Requirement that establishes a minimum level of firm dispatchable resources that is required to serve our customers' needs in every hour of every day. The Reliability Requirement was developed through analysis of industry trends and careful study of our system's performance (and the broader MISO system's performance) during both winter and summer days when renewables were unavailable, sometimes for lengthy durations. We discuss the development of the Reliability Requirement in greater detail in Appendix J2.

This Requirement does not drive any resource additions in our Preferred Plan until after 2030. Prior to 2030, our Preferred Plan relies on two primary sources to ensure reliability: (1) the MEC and Sherco CCs and (2) our nuclear units. With respect to the CC units, intermediate gas resources efficiently address reliability challenges because they can vary output to adapt as demand for electricity changes over the course of the day and year. The CC units are large rotating machines, so also provide important grid stability benefits and can also play an important role in our blackstart plans.[1] With respect to nuclear generation, our proposed Monticello extension not only represents a carbon-free workhorse of a resource, it also enhances fuel diversity and provides a generation resource that is not subject to seasonal fuel supply limitations.

C. Cost

Along with leading the clean energy transition and enhancing the customer experience, keeping customer costs low is one of Xcel Energy's central, guiding objectives. Since our last Resource Plan, renewable technology costs – and in particular, solar costs – have continued to decline; we expect this trend to continue going forward. Taking advantage of technological advancements is one reason that we can deliver a Preferred Plan that delivers deep carbon reductions for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the planning period. And over the long run, our Preferred Plan is expected to yield net present value savings. In comparison to the Reference Case, which does not

[1] As previously discussed, upcoming generation retirements will impact our current blackstart plans (*i.e.,* our ability to restart the system in the event of a catastrophic failure). While we do not propose any specific action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

include accelerated coal retirements or an extension of the Monticello nuclear unit, the Preferred Plan yields $203 million of benefits on present value revenue requirements (PVRR) basis and $461 million of benefits on a present value societal costs (PVSC) basis.

D. Risk and Flexibility

Finally, while holding environmental, reliability, and cost objectives in balance, we also seek to mitigate customer risk by ensuring fuel diversity, maintaining appropriate capacity length in our portfolio, and maintaining flexibility in our plans. Portfolio fuel diversity is essential to risk mitigation – especially so, as we transition away from coal. Incorporating a mix of nuclear, load management, intermediate and peaking natural gas capacity, and renewables into our long-term plans ensures that our portfolio is adequately diverse and mitigates the risk associated with overdependence on any one fuel source. Further, the proposed resource additions identified in our Preferred Plan result in a capacity position that is between 500 to 1,000 MW long in any given year. We believe this modest length is prudent, particularly as we propose to substantially increase renewable resources – adding more than 4,000 MW of incremental new renewable capacity, much of which we anticipate will be grid-scale solar – in addition to our already large wind fleet.

Both MISO and independent analyses suggest that capacity accreditation for solar in particular will decline substantially as more capacity is added. We expect MISO will ultimately recognize this conclusion from its ongoing study of issues associated with integration of high levels of renewables in its planning construct.[2] Therefore, what we believe today to be a long capacity position may actually erode over time.

Maintaining a significant amount of flexibility in our future plans is essential to reliably and affordably navigating the transition of our fleet. To that end, we are deferring a decision on pursuing a license extension at the Prairie Island nuclear plant to subsequent resource plans, thereby preserving flexibility to respond to market conditions at that time. We are also optimistic that the firm dispatchable, load supporting resources needed in the post-2030 timeframe could be provided by new non-emitting technologies rather than traditional gas CTs. In addition, as we look to add solar resources to meet capacity needs in the mid to late 2020s, we are also open to allowing other resource types to compete, to ensure that we secure the most cost-effective resource solutions for our customers. As the industry and technology

[2] We discuss MISO's *Renewable Integration Impact Assessment* (RIIA) in more detail in our Baseload Study, provided as Appendix J1.

continue to rapidly evolve we will evaluate opportunities to bring these potential alternative solutions onto our grid.

E. Our Employees and Communities

Underscoring all four of our objectives is our commitment to our employees and the communities within which we operate. We do not make plant closure decisions lightly, and we are committed to supporting our employees at the Sherco and King plants as we prepare to retire these facilities. In the past we have provided career support services to our employees facing plant closures, and we expect to continue providing this support in the future. We also know that the Company is a major presence in terms of employment and local tax revenues in Becker and Oak Park Heights and the surrounding areas. We also have partners at our Sherco site with Liberty Paper and SMMPA (Southern Minnesota Municipal Power Agency). We are currently participating, alongside Minnesota Power, in a Host Community Impact study, to better understand the potential impact of power plant retirements on host communities. A similar study helped inform our work with the communities surrounding our Sherco 1 and 2 Units, and their planned closure as approved in our last Resource Plan. Since that time, we have worked with Becker and Sherburne County, as well as existing and prospective customers to spur economic development in the area, which also includes our plans to build, own, and operate the Sherco CC. As discussed in Appendix O1: Summary of IRP Stakeholder Engagement, we are committed to continue to work with our employees and communities to navigate this transition together.

II. THE PREFERRED PLAN

Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of analysis and information sharing. As a result of those efforts – as well as the significant engagement of our stakeholder community over the past year, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process.

Significant consensus has emerged around the following components of our Preferred Plan:

- Elimination of coal-fired generation from our system by 2030,
- Reduced, seasonal dispatch of Sherco Unit 2 until its retirement in 2023,
- Acquisition of at least 3,000 MW of utility-scale solar by 2030,

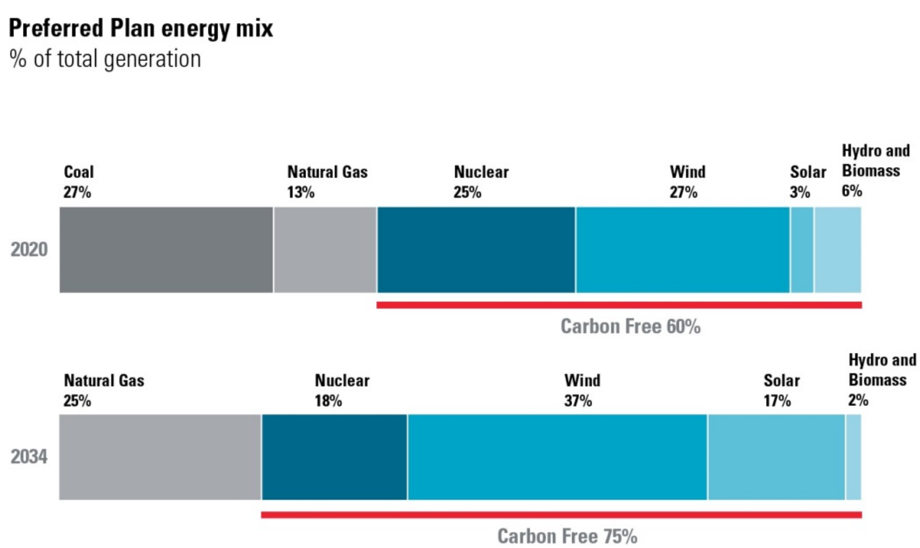
- A substantial increase in EE savings, and
- Support for the Company's proposal to take ownership of the MEC.

Our Preferred Plan builds upon this foundation and includes even more renewable resources, additional DR resources, continued operation of our carbon-free Monticello nuclear plant for an additional 10 years, and a new CC at our Sherco site. In the balance of this section, we present the change in our Energy Mix that will result from our Preferred Plan, and discuss key aspects of the transition below.

A. Transforming Our Energy Mix

From an energy mix perspective, the Preferred Plan eliminates the coal energy contribution and increases the renewable energy contribution by over 20 percent by 2034, rising to approximately 56 percent.

Figure 4-2: Preferred Plan Energy Mix



The fleet transformation underlying our Preferred Plan achieves a nearly 84 percent reduction in CO_2 emissions from 2005 levels by 2030, and maintains at least an 80 percent CO2 reduction through 2034.

Table 4-1 below presents the amount and timing of the resource additions that comprise our Preferred Plan.

Table 4-1: Preferred Plan Resource Additions (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**290**	**226**	**777**	**752**	**2,098**	**700**	**784**	**693**	**838**	**700**	**1,065**	**997**

In the next section, we discuss key aspects of our Preferred Plan and our fleet transition in more detail.

B. Fleet Transition

Our 2020-2034 Resource Plan represents a progressive step forward in transitioning our fleet – meaning that the Company will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan to retire approximately 2,400 MW of coal-fired generation in the next decade. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing this capacity includes a significant amount of additional renewable generation supported by natural gas CC resources, continued reliance on nuclear generation, and large EE and DR additions during the planning period.

1. Renewable Resources

Substantial renewable additions are a central component of our energy future and a cornerstone of this Preferred Plan. Although the quantities of future wind and solar additions may shift somewhat in concert with technology and market fluctuations, our commitment to renewable energy will not. In total, our Preferred Plan envisions a system that is approaching 60 percent renewable in 2034. High levels of renewables combined with cost-effective gas and nuclear generation will combine to create a safe and reliable system that will withstand the summer and winter extremes of the Upper Midwest. Our Preferred Plan proposes to add at least 4,000 MW of cumulative utility-scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of wind by 2034, to replace wind that would otherwise retire from our system during that period.

With these additions, there would be enough solar generation to power more than 650,000 homes each year. Wind generation also continues to play a prominent role in this Preferred Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last resource plan and our 1,850 MW wind portfolio. By 2034, wind will provide 37 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

2. *Coal Resources*

Large coal-based generating units have been an important baseload resource to stable grid operations for many decades. As we and other utilities move away from coal for economic, environmental and public policy reasons, we must do so with the maintenance of a resilient and reliable grid at the forefront of our minds.

In our most recent Resource Plan, the Commission approved our proposal to retire our Sherco Units 1 and 2 in 2026 and 2023, respectively. Our proposal to retire these units early was informed by technical analyses that also determined the Sherco CC included in this Preferred Plan is essential to mitigate grid issues. Similarly, our proposal in this Resource Plan to retire our remaining two coals units early – King in 2028 (nine years early), and Sherco 3 in 2030 (ten years early) – is informed by technical and other analyses discussed in our Baseload Study, provided as Appendix J1. As also described in the Economic Modeling Framework Chapter of this Resource Plan, we have included estimated grid reliability mitigation costs into our Strategist modeling underlying the Preferred Plan.

Finally, our Preferred Plan also includes a commitment to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023 and Commission consideration.

3. *Nuclear Resources*

Our Preferred Plan proposes to operate our Monticello nuclear unit through 2040 (10 years longer than its current license), and continued operation of both of our Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3] Nuclear is central to achieving our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability.

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.

Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical component of our reliability strategy. Finally, the continued operation of Monticello contributes to the affordability of our plan by leveraging an existing, high-performing asset on our system. We discuss the benefits of nuclear, as well as the performance of our nuclear fleet, in greater detail in Appendix K.

4. *Combined Cycle Resources*

In addition to our carbon-free nuclear baseload, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables, because we can ramp the output of these resources up or down in response to our system's changing needs throughout the day as renewable resources generate more or less due to their variable nature. To that end, our Preferred Plan includes our proposed acquisition of MEC,[4] which is a 760 MW two-unit CC, as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s.

As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy. As discussed in our last Resource Plan, siting a CC at the existing Sherco site will cost-effectively address grid issues identified by the MISO Attachment Y2 study of the Sherco Unit 1 and 2 retirements. Additionally, the Sherco CC will primarily offset the retirement of other gas units on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). Replacing this capacity is not only reasonable but operationally necessary in light of the much larger coal retirements planned and the large amounts of variable renewable additions we anticipate in the same period. The Sherco CC will also mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota. We discuss the Sherco CC further in Appendix L.

[4] As proposed in Docket No. IP6949,E002/PA-18-702. We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

5. *Firm and Dispatchable Load Supporting Resources*

Reliability is central to resource planning. We are particularly focused on the reliability of our system in this Resource Plan, however, as we embark on a complete transformation of our baseload fleet, and transition to a portfolio of variable renewables that approaches 60 percent of our overall generation. Our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses by ensuring a resilient grid that enables us to meet our obligation to provide reliable service.

To this end, our Preferred Plan proposes to begin adding approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources in the 2031 to 2034 timeframe. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis underlying this Resource Plan demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired.

That said, because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced grid investments could position DR to better compete with traditional generation for this purpose. We are committed to pursuing all of these options not only in the longer term, but also in the near-term in order to leverage this technology as it matures. Generally, by keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan, but allow the market to advance as we submit future Resource Plans, continue to collaborate with our stakeholders, and engage with the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. *Energy Efficiency and Demand Response*

Demand Side Management (DSM, which collectively is EE and DR) resources empower our customers to control their energy usage and their monthly electric bills. Load control DR programs are an important part of our resource mix as they can be used during periods of peak demand, helping maintain system reliability. EE reduces the consumption of energy all together, which has both system and environmental benefits. Taken together, DSM resources are an important part of maintaining system reliability as well reaching our environmental goals.

The DSM aspects of our Preferred Plan includes average annual energy savings of over 780 GWh in each of 2020-2034, compared to average annual energy savings of 444 GWh in our last Resource Plan. In addition, our Preferred Plan also incorporates an incremental 400 MW of DR by 2023 and grows to over 1,500 MW total by the end of the planning period. Importantly, this Resource Plan also signals a change in how we approach EE. In previous plans, we have treated EE as a reduction to customer load. In this Resource Plan, EE is considered a supply-side resource that the economic modeling considers alongside other resource types.

In our last Resource Plan, the Commission approved 1.5 percent annual EE savings on a go-forward basis. The level of EE we propose in this Plan is based on the 2018 *Minnesota Energy Efficiency Potential Study,* and proposes to achieve savings levels ranging from approximately two percent to 2.5 percent annually. This level of EE achieves more than 800 MW of additional demand savings by 2034 compared to the 1.5 percent level approved in our last Resource Plan.

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023, and grows our total portfolio to over 1,500 MW total by the end of the planning period. When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In our last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines (CTs). As can be seen in our analysis, however, no CTs or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers solar additions in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another non-conventional DR program that automates control of various end-uses like HVAC and lighting.

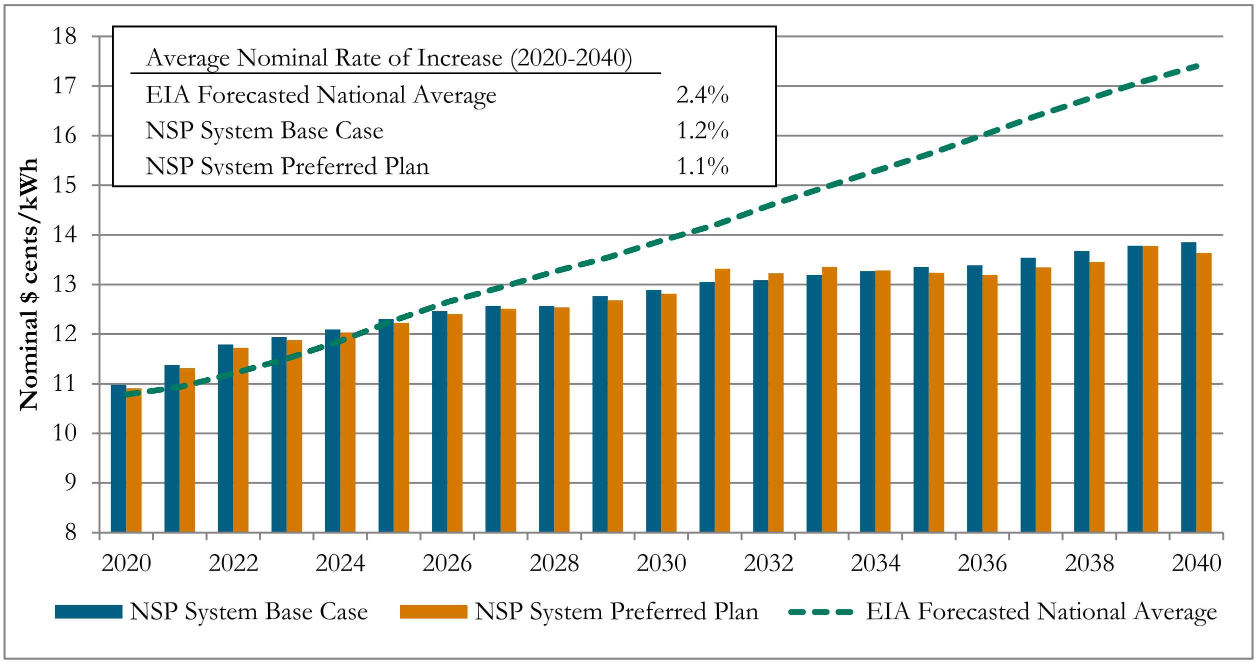
We believe the advancement of our grid, and technology generally, may take the form of less traditional DR, so with this Resource Plan we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years. Our objective with this resource type is to bring forward information on several viable options so the Commission, stakeholders, and the Company can engage in an informed exchange. We provide an analysis and detailed discussion of EE and DR in Appendix G1. We also discuss how we applied EE and DR as supply-side resources in our Strategist modeling in Chapter 5. Economic Modeling Framework.

C. Keeping Rates Affordable for Customers

Our Preferred Plan keeps annual cost growth at or below the rate of inflation. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly consistent with the expected national average increase in electricity prices.

To show the cost impact of our Preferred Plan over the long-term, we provide as Figure 4-3 below, a CAGR comparison to the national average nominal cost CAGR.

Figure 4-3: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[5] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model. The modest cost increase associated with our plan is attributable, in large part, to our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. We believe technological improvements will continue to drive the costs of renewables down, which is a key driver in our strategy of proposing significant solar additions in the latter half of the next decade.

We provide our full analysis and discussion regarding customer cost and rate impacts in Chapter 6: Customer Cost and Rate Impacts.

[5] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

In the next section, we discuss the actions we plan to take over the next five years, and in the longer term, to achieve our Preferred Plan and deliver on our goals to achieve deep carbon reductions in our electricity mix.

III. ACTION PLANS

A. Five-Year Plan

Our Preferred Plan does not identify any incremental capacity needs through 2024. Thus, our actions in the next five years primarily address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer needs, and continuing to achieve reductions in energy demand and load through ambitious DSM programs. We also plan to make targeted investments in supporting infrastructure to accommodate increased renewable energy and DER on the grid, and to gain operational experience with technologies that may play a larger role on our grid in the future.

Wind. We expect that the 1,850 MW of wind generation resulting from our recent acquisitions and RFPs will achieve commercial operation by 2022. These additions were assumed across all of our scenario analyses. Further, we expect to replace the approximately 170 MW of wind capacity that will expire in the next five years. We are committed to pursuing repowering and/or contract extension opportunities for this capacity, as part of our "no going back" renewables strategy. Further, we intend to pursue incremental renewable resources as needed to meet customer needs in growing customer programs like Renewable*Connect.

Solar. Our Preferred Plan includes significant amounts of large scale solar resources. However, the initial planned addition of 500 MW does not occur until 2025, which is just outside of our five-year Action Plan window. In order to procure this initial tranche of solar, we expect to implement a competitive acquisition process in the 2023 to 2024 timeframe. We expect this timeline will allow us sufficient lead time to acquire these solar resources and bring them online by the end of 2025.

On the distributed solar side, we have included forecasted growth in our plan. If actual distributed solar capacity additions exceed our expectations, we anticipate this will simply displace a portion of our proposed utility-scale solar resources.

Hydro. We anticipate adding 125 MW of energy and capacity through a PPA with Manitoba Hydro in 2021. This incremental contract with Manitoba Hydro is in addition to our existing PPA and diversity exchange and was executed in 2010.

Nuclear. Our Preferred Plan includes a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. While the license does not end until 2030, we expect to begin a Certificate of Need proceeding with the Commission within the next five years. We also expect to begin working toward license extension with the NRC during this timeframe.

Natural Gas/Oil Peaking. We anticipate extending the life of Blue Lake Units 1-4 through 2020-2023,[6] which provides 153 MW of peaking capacity to the NSP System. Our Preferred Plan further includes our acquisition of MEC, which is currently pending Commission consideration. Finally, we plan to continue development activities associated with the Sherco CC during the next five years.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 1, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

Demand Response. Our Preferred Plan proposes to acquire 400 MW of DR resources by 2023, which we intend to evaluate and pursue through a variety of means and technologies over the coming years.

Supporting infrastructure. Aside from the grid-scale and DER additions included in our Plan, sufficient supporting infrastructure is essential to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. For example, we anticipate completing transmission investments, such as the Huntly-Wilmarth project, in late 2021. We expect further and substantial transmission infrastructure development will be necessary over the long-term, which will involve planning in the near-term. We also are continuing to refine our advanced grid strategy and intend to propose implementation of foundational grid modernization investments – and continue our work to integrate

[6] Pending decision in Docket E,G002/D-19-161

planning processes at all levels of the grid.

Gaining technology experience. As discussed above, we know that energy storage will be essential for our future grid, in order to integrate variable renewable energy without the use of traditional firm dispatchable generation. In the near term, we plan to take steps to gain additional experience with energy storage in the NSP system. For instance, we are co-investing in a microgrid project with Fort McCoy in the NSPW system that will pair solar with storage as a resiliency solution, supplementing traditional diesel backup generators. This project, slated to come online in 2021, will not only support resiliency at Fort McCoy, but will also help us gain valuable experience in maintaining and operating an energy storage facility, especially in the context of new market guidelines in MISO. We anticipate that it will produce income streams to the benefit of all customers through energy price arbitrage, ancillary services, and using the battery as a capacity resource.

Resource treatment across states. We continue to explore options with the North Dakota Public Service Commission to create a resource planning process that can more formally accommodate generation portfolio preferences. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address differing energy policies and changes in cost allocations that may result.

B. Long-Term Plan

By 2025 we expect we will have achieved approximately 60 percent CO_2 reduction from 2005 levels, per the measures highlighted in our Preferred Plan. In the 2025 and beyond timeframe, there are several key aspects of our system that we will need to address to ensure we can achieve both our 2030 carbon reduction goals, and ultimately, our longer term goals to achieve 100 percent carbon-free electricity. For instance, we anticipate that increasing levels of variable renewable energy and additional baseload unit retirements will necessarily affect the way MISO plans for the broader grid in the future. Notwithstanding the rapid pace of change occurring in our industry, there are several action items on our long-term planning horizon.

New Transmission Infrastructure. Increasing renewable energy on the broader MISO grid is nearly a certainty; wind and solar projects make up over 85 percent of proposed capacity currently in the MISO generator interconnection queue.[7] However, as noted

[7] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

previously, the queue process is mired with delays and high interconnection cost estimates, in large part due to a lack of available transmission capacity. While generator replacement processes will help us place renewables on our system using existing interconnection rights to an extent, we will need more transmission capacity to come online to effectively achieve the level of renewables we envision on our system – and more broadly within MISO – by 2030 and beyond.

Increasing energy storage on our system. As previously noted we expect that battery energy storage system costs have room to decline over the next several years. We also know that, as variable renewable adoption on the grid increases and more baseload capacity comes offline, we will need a mix of low and non-emitting technologies that can address renewable variability and ensure reliability cost effectively for customers. Battery energy storage holds substantial promise for meeting these needs, and given expected cost declines, we anticipate that we will be able to install cost effective energy storage on the NSP System in the future.

Prairie Island. Our Preferred Plan continues the operation of both Units to the end of their current operating licenses – 2033 for Unit 1 and 2034 for Unit 2. Our baseload scenario modeling results presented in the next Chapter show that there may be value in extending the life of this plant. However, given our operating licenses extend nearly to the end of the planning period, we do not yet need to begin pursuing relicensing. Therefore, we plan to continue working with our stakeholders and evaluate Prairie Island in the context of our future system in subsequent resource planning cycles, rather than locking into a decision at this time. In the meantime, however, Prairie Island continues to serve an important function on the grid and in providing cost-effective and carbon-free baseload power through the planning period.

North Dakota CT. As discussed further in Part IV below, the Company agreed to take steps to locate a natural gas CT in the state of North Dakota, to be operational by December 31, 2025. We remain committed to locating more generation in North Dakota in the future, and we expect to address this resource in our next Resource Plan.

Meeting Statewide Statutory Environmental Goals. Minnesota's Next Generation Energy Act contains a goal for statewide carbon reductions of 80 percent (from 2005 levels) by 2050. While the statewide goal is for all sectors, the Preferred Plan we propose in this Resource Plan achieves over 80 percent reduction by 2030. We know that the electric sector has a unique role to play in achieving the statewide goals. E3's Minnesota PATHWAYS Report, included as Appendix P3, indicates that reducing carbon emissions in the electricity sector enables beneficial electrification to further mitigate emissions in other sectors – in particular the transportation and building sectors. As we discuss in this Resource Plan, our path to achieving 80 percent carbon reduction from 2005 levels in our system relies on retiring baseload coal units, increasing renewable energy, extending nuclear operating licenses, and implementing incremental DSM, and including energy storage. To be sure, all electric utility systems are different and will encounter different challenges on their path to carbon reduction – and there remain challenges to maintaining that level of carbon reduction if current barriers (e.g. transmission constraints or lack of cost effective long-duration storage options) are not mitigated. However, the analysis findings that led us to our current Preferred Plan give us confidence that the electric sector as a whole can help achieve Minnesota's 80 percent carbon reduction by 2050 goal. We further discuss our outlook regarding this statewide goal and potential barriers in Appendix H.

Meeting Company Goals to Achieve 100 Percent Carbon Free Electricity by 2050. As noted throughout this Resource Plan, our Preferred Plan charts a path toward achieving our 2030 carbon reduction goals, and positions us to address our longer term vision of achieving 100 percent carbon-free electricity by 2050. This goal, however, is not one we can achieve cost-effectively or reliably without substantial technological breakthroughs. This includes, in particular, carbon-free dispatchable energy resources that will help us balance variable renewables' output relative to customer demand. Significant research and development is required to bring potential new technologies to commercialization stage; these could include solutions such as longer-duration battery energy storage, other types of energy storage, hydrogen-fired generation, advanced nuclear technologies, carbon capture and storage, and others.[8] We continue to monitor potential emerging technologies and are excited to see what applications will emerge to help make our vision a reality in the long term.

IV. NORTH DAKOTA PLAN

As discussed in the Planning Landscape, we plan and operate a single Upper Midwest system that serves customers in five states. Consistent with the terms of the Settlement in Case No. PU-07-776, since 2008 we have filed our Upper Midwest Resource Plans with the North Dakota Commission, and included in each of them an analysis of a Resource Plan scenario compliant with Federal and North Dakota laws only. As with the previous 2016-2030 Upper Midwest Resource Plan, the current Plan refers to this scenario as simply the "North Dakota Plan."

[8] Selected emerging technologies are discussed further in Appendix F6.

A. Plan Components

Our Preferred Plan for our Upper Midwest system is designed to support the Company's goal of an 80 percent reduction in carbon emissions by 2030. Our 2030 goal is not driven by a particular policy directive from one of our jurisdictions. We believe planning to meet this goal is in the best interest of all our customers. Therefore, this objective is reflected in our North Dakota Plan. The North Dakota Plan differs from the Preferred Plan in the following ways:

1. All CO_2 costs have been removed;
2. Incremental Demand Response (DR) was removed; and
3. Community Solar Garden (CSG) program costs are excluded.

When we developed our Preferred Plan we included the externality and regulatory costs of CO_2 approved by the Minnesota Public Utilities Commission. Removing the CO_2 in the North Dakota Plan had only minor impacts as shown below:

Table 4-2: Expansion Plan Comparisons
Preferred Plan – North Dakota Plan – Summary of Differences

Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	542
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

North Dakota Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	500	0	1000	1000	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

Difference - North Dakota Plan Compared to Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	0	0	-500	-500	500	500	0	0	0	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	-270	-20	-21	-10	-17	-41	-12	-14	-15	-17	-19	-20	-21	-22	-23	-542
EE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the modeling for the North Dakota Plan, solar additions for 2027-2029 in the Preferred Plan are delayed to 2029-2030. As discussed previously, our Preferred Plan also includes a large incremental addition of DR in recognition of the Minnesota Commission's Order in our last Resource Plan requiring 400 MW of additional DR by 2023. While we expect most of these DR programs to be implemented in Minnesota, as we continue to develop additional DR programs for our system we would consider proposing to add cost-effective DR programs for our North Dakota customers as well.

The exclusion of the costs of CSG does not impact the resources additions for the North Dakota Plan. Instead, the costs of CSG are allocated so that North Dakota customers pay a market rate for the energy from the CSG resources. The allocation of the costs to North Dakota will also reflect previous cost-recovery decisions that exclude costs related to the disputed resources identified in the rate case Settlement of Case No. PU-12-813 and subsequent cases.

B. Resource Planning Framework Status

On December 21, 2018 we proposed a framework that outlined essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion.[9] We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year. The North Dakota Commission confirmed that they are interested in a more formalized resource planning process. We look forward to working with the North Dakota Commission and Staff to further develop a North Dakota planning process.

C. North Dakota Combustion Turbine

Pursuant to the Settlement in Case No. PU-12-813, the Company agreed to take steps to locate a system natural gas CT in the state of North Dakota, to be operational by December 31, 2025. Specifically, Xcel Energy agreed to:

> *…develop, own, and operate (or alternatively, cause to be developed and operated on its behalf through a power purchase agreement or other contractual arrangement) a combustion turbine with a capacity of at least 200 MW in eastern North Dakota, no later than December 31, 2025. The costs of the generating facility will be allocated to all state jurisdictions served by the Company in a manner consistent with other NSP System resources. Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to in this paragraph reasonably 1) addresses a system capacity need and 2) represents a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota.*

The five-year Action Plan associated with this 2020-2034 Resource Plan runs through

[9] *See* North Dakota Case No. PU-12-813.

2024. Thus, the Commission will not find specific mention of a North Dakota natural gas CT addition in the current short-term Action Plan; rather, proposed resource additions in 2025 will be within the Action Plan developed in the next Resource Planning cycle and addressed directly in that filing.

While the longer-term plan for resource additions do not reflect a firm peaking addition until 2031, we acknowledge the above-stated Settlement commitment and will continue to assess NSP System capacity needs over the next couple of years, the likelihood of gaining the necessary approvals in all NSP System states, and the operational feasibility and cost-effectiveness of a peaking plant located in eastern North Dakota. Given the long planning horizons, many things can change in the next 5 to 10 years in terms of energy policy, technology, and economic conditions. We remain committed to locating more generation in the state and a more timely and beneficial option may become evident over time.

V. PUBLIC INTEREST ANALYSIS

Based on our detailed analysis, we conclude that the Preferred Plan is in the public interest. We believe it best balances our goals to ensure reliability, achieve significant carbon reduction, and maintain reasonable costs to customers.

The Commission's Rules identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest.[10] Specifically, these Rules require that resource options and resource plans are to be evaluated on their ability to:

- Maintain or improve the adequacy and reliability of utility service,
- Keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints,
- Minimize adverse socioeconomic effects and adverse effects upon the environment,
- Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
- Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

[10] Minn. R. 7843.0500, subp. 3.

Our Preferred Plan is best able to meet these criteria, especially when analyzed on a comprehensive basis in light of the planning landscape the Company and the broader industry operate within.

A. Reliability

Our Preferred Plan is designed to allow us to continue to provide safe and reliable service to our customers as we take steps to achieve deep carbon reductions in our electricity mix. We know that as we, and other utilities in Minnesota, the Upper Midwest, and the broader MISO market retire baseload units and continue to add substantial variable renewable generation capacity to the grid, planning processes will need to adapt to ensure a reliable and stable grid. We have done the work to understand potential grid impacts from the orderly fleet transition we propose. We have also developed a Reliability Requirement that will ensure we continue to serve our customers' energy needs every hour of every day in the interim until MISO updates its planning construct to recognize the changes underway. We discuss the work we have done to we meet our obligation to provide reliable service in our Baseload Study, provided as Appendix J1.

Related, in connection with our pursuit of vast new quantities of renewables, we have included the proposed MEC acquisition and planned Sherco CC as resources in our Preferred Plan in order to ensure new renewable resources can be adequately integrated. We also leave open the possibility that future firm, dispatchable needs identified in the Plan could be met with non-emitting alternatives such as DR or energy storage. Finally, we discuss other supporting infrastructure that will support our goals to integrate additional variable renewable energy in Appendix I. By including these various elements, our Preferred Plan positions us to ensure the continued adequacy and reliability of the NSP system throughout the planning period and beyond.

B. Impact to Customer Bills

Affordability is one of the key objectives that framed our analysis. Our Preferred Plan achieves significant carbon reductions while ensuring reliability at a cost in line with expected inflation rates, or an annual cost increase of just over one percent, on average, over the planning period. The fact that we do not need to take any actions in the near-term supports the flexibility that we seek with this plan, which we believe is more beneficial now than ever – given the pace of technological innovation and cost reductions we have observed and expect to continue into the future. Therefore, we believe that our Preferred Plan will keep our rates as low as practicable, given future market and other uncertainties as we have described in this Plan.

C. Environmental Effects

Xcel Energy is leading the nation with an ambitious goal of serving our customers with a completely carbon-free resource mix by 2050 – and on our way to reaching this goal, reducing our carbon emissions by 80 percent from 2005 levels by 2030. Our Preferred Plan is a critical step in planning to meet these ambitious carbon reduction goals, while also keeping in mind the socioeconomic impacts of retiring large baseload generation units. We have proposed to close all of our remaining coal units by the end of 2030, which will significantly reduce the amount of carbon attributable to our system. At the same time, we are also planning to vastly expand the amount of renewable energy capacity on our system, and continue to operate Monticello through 2040 – both of which will provide substantial amounts of clean energy to serve our customers. All of these actions work to ensure we achieve our environmental goals and carbon-free vision.[11]

D. Socioeconomic Impacts

We recognize that plant closures can have a significant impact on our plant employees and the communities that have hosted our plants for many years – and we bore this in mind when developing our Preferred Plan. By announcing our plans to retire Sherco 3 and King far in advance of proposed retirement dates, employees will have time to build additional skills and transition to other parts of the Company, if desired. Like we have in the past, we will work with these employees to support their transitions. We will also continue working with the host communities and other stakeholders around those communities. We are currently working, in conjunction with CEE and Minnesota Power, to understand the socioeconomic effects of the plants and their closure on host communities. This commitment is evidenced in the work we have been doing in the Sherco area, after closure of our Sherco Units 1 and 2 was approved in our last Resource Plan. Among others things, we plan to develop our own gas CC plant on the Sherco site. We have been working to draw new development to the area, and with existing and prospective large industrial customers to locate facilities in the area, which will help to offset tax and other impacts from the closure of the coal units. These efforts will generate socioeconomic benefits through facility construction and ongoing operations. Our clean energy efforts also generate socioeconomic benefits, both in preserving key nuclear jobs through the Monticello

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[11] Note that resources we include our Preferred Plan meets and exceeds Minnesota greenhouse gas reduction goals under 216H.02, the renewable energy standard under 216B.1691 and the solar energy standard under 216B.1691, 2f.

life extension, and spurring a large amount of new renewable construction over the planning period.

E. Flexibility to Respond to Change

Our Preferred Plan positions the Company well in the current planning landscape – meeting near-term needs and creating flexibility for the future. As we have described, planning constructs, policies, and technology costs are all creating uncertainty, which lead us to prioritize strategic flexibility in our plans to preserve the most value for our customers. For example, even though our modeling results show that extending the operating life of Prairie Island would be cost-effective under today's market conditions, we also know those conditions can change rapidly. Thus, we have deferred a decision regarding Prairie Island extension until the next Resource Plan. We also have said that we are open to meeting our firm and dispatchable capacity needs in the out-years of our Plan with options other than natural gas units, to the extent technologies sufficiently develop and are economically-favorable at that time. This flexibility enhances our ability to respond to changes in our planning landscape that would affect our operations during the planning period and preserves some agility for us to respond and adapt to these factors

F. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Preferred Plan limits the risk of adverse effects on the Company and our customers from factors beyond our control. For example, the Reliability Requirement we developed and incorporated into our modeling ensures that we have planned for adequate firm and dispatchable energy to meet our customers' needs until current planning constructs adapt.

Our Preferred Plan represents the best option to meet customers' needs in light of the planning landscape for the planning period, presents the best path forward for the Company, our customers, and the energy future of our Upper Midwest system, and is thus in the public interest.

VI. CONCLUSION

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. Our Preferred Plan proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 5
ECONOMIC MODELING FRAMEWORK

We have used the Strategist Resource Planning model to perform our economic analyses since 2000. We use Strategist as our primary resource planning software to estimate the costs of various resource expansion plan options, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. Strategist results are a decision support tool to guide development and selection of a Preferred Plan and test the robustness of the Plan under a variety of assumptions and sensitivities.

To ultimately identify and refine our Preferred Plan, we created 15 scenarios that examined different combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We refer to these scenarios as "baseload study scenarios."

As we developed the various baseload study scenarios, we also conducted DR and EE Bundle analyses. This is the first Resource Plan in which DR and EE Bundles are considered supply-side resources, and as such, we had to undertake iterative analysis alongside our scenario analysis to analyze these options appropriately. Finally, after this analysis was completed, we used the outcomes and sensitivity tests to select and refine a Preferred Plan.

We discuss our assumptions, scenarios, sensitivities and how these inputs guided selection of our Preferred Plan in more detail below.

I. ASSUMPTIONS

There are several assumptions included in our baseline data inputs that are common across all scenarios studied. These factors may, in some cases, be varied within sensitivities, but are largely kept constant across the default study of each scenario.

Important starting assumptions in our analysis include:

Load Forecast. The Company employs standard probabilistic analyses to determine our load and energy demand forecasts. Our resource planning process takes the 50 percent probability level forecasts for both peak demand and energy requirements as an input, we provide a detailed description of our load forecasting methodology as Appendix F1.

In the past, these forecasts have included adjustments to account for the effects of EE as a load modifier. In order to accommodate modeling EE as a supply-side resource in this Resource Planning process, we have not included any going forward EE impacts in the load forecast for the 2020-2034 period. These energy and demand savings are now included in the three EE Bundles that we evaluate as supply-side resources.

We also incorporated an effective planning reserve margin of 2.98 percent, per MISO requirements. As discussed in Chapter 3, MISO instituted an 8.4 percent planning reserve margin requirement in the 2018-2019 planning year, and our system has a 95 percent MISO system coincident factor. Thus, our effective reserve margin is calculated in the following manner:

Figure 5-1: Effective Reserve Margin Used in Strategist Modeling

$$(95\, percent\ coincidence\ factor)\ x\ (1 + 8.4\, percent) - 1 = 2.98\, percent\ effective\ reserve\ margin$$

Existing Fleet. We develop forecasts to model our existing fleet's cost and performance assumptions (such as variable O&M, heat rate, forced outage rate, maintenance requirements, etc.) based on historical data, with adjustments for known future changes where applicable. Additional operational and performance assumptions include:

- Retirement of Sherco Units 1 and 2 in 2026 and 2023, respectively, as approved in our last Resource Plan;
- Remaining coal units are dispatched economically beginning in 2028, reflecting our expectations that MISO transitions to a multi-day commitment approach that more efficiently commits resources in accordance with load serving needs over a longer time horizon;
- Retirement of all other facilities at their current expected end of life if within the resource planning period, unless we have specifically included costs of life extension (e.g. for nuclear units in scenarios that include life extension);
- Continuation of our existing PPAs until their contractual termination dates, and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Additional cost –related assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Costs associated with early retirement of the existing baseload coal units (King and Sherco 3), as well as costs for early retirement or re-licensing the nuclear plants were developed for use in the Baseload Study modeling.

Renewable Energy. In addition to the 1,850 MW of wind we are in the process of adding to the NSP System since our last Resource Plan, we have assumed:

- Currently approved and/or operating renewable facilities (including both those facilities we plan to own and those we plan to contract) are assumed to be replaced at their end of life or contract expiration with the equivalent amount of similar energy from generic wind and solar resources (i.e. wind would replace wind, solar would replace solar). We refer to this as "no going back;"
- Accreditation of wind resources based on the 2018-2019 Planning Year 15.6 percent MISO ELCC, accreditation of solar resources at the default 50 percent ELCC. For modeling purposes we assume these values remain the same throughout the modeling period;
- No extension of the federal production tax credit (PTC) or investment tax credit (ITC)[1] past the expiration dates as per current law.

Markets. We run scenarios in Strategist both with "markets on" (i.e. where we can buy and sell energy in the MISO wholesale market) and "markets off" (i.e. where we cannot sell to the market, but purchases are still modeled). We use the "markets on" view as a default assumption because this is more reflective of our realistic operations. Sensitivities with markets off help us test the effects of this assumption on the various scenarios.

Wholesale electricity price forecasts. Our electric power market prices are developed from fundamentally-based forecasts from external analysts Wood Mackenzie, CERA and PIRA. The forecasts we receive from these third party analysts provide monthly average on- and off-peak market pricing at the Minn Hub. We then use that market data to create an hourly shape for each month, based on the amount of thermal generation dispatched on our system. The methodology results in lower hourly locational marginal prices (LMPs) during times when a significant amount of renewable energy is on the system and higher hourly LMPs when amounts of available renewable energy are lower. Shaping the hourly prices in this manner provides a more conservative view of potential benefits we may realize from selling excess generation to the market.

[1] The ITC reverts to 10% in 2022 and beyond, per current law.

Purchase and sales limits. In our Strategist model, we include a limit as to the amount of energy that we are able to either purchase from or sell into the MISO market. This limit was developed using results from the 2018 MISO Transmission Expansion Plan (MTEP) model results and evaluating maximum levels of market interaction achieved in that modeling. For 2020-2023 we assume a market interaction limit of 1,800 MW which grows to 2,300 MW after 2023, based on the anticipated in service of the Cardinal to Hickory Creek transmission line which is expected to increase transmission outlet in our region.

Emissions rates and costs. Emission rates for existing and planned resources are consistent with historical and expected performance. We assume the following costs[2] and apply them to emitting resources as relevant:

- Achievement of an 80 percent reduction in CO_2 serving retail customers, as measured from 2005 levels, by 2030. The overall carbon emissions are allowed to increase slightly from these levels at the retirement dates of the nuclear fleet, which vary by scenario;
- $ 25.00 per ton CO_2 as a regulatory cost, starting in 2025 and escalating at inflation, with the high CO_2 externality value used prior to 2025. The societal value of CO_2 as an externality and other combinations of externality and regulatory costs were included as sensitivity cases;
- The Minnesota Commission's high externality values for other specified emissions.

Generic Resources. Strategist uses generically-defined resources to meet future demand when our already existing and approved resources are not sufficient in a given year. Generic resources are modeled as incremental units of a certain installed capacity size, but these sizes are chosen based on the amount of UCAP, or the MISO accredited capacity value the units would yield. For example, although the generic unit size for solar is rather large (500 MW installed capacity), the resource adequacy or MISO capacity credit value we would expect to receive for a plant of that size is half that (250 MW), which is more comparable to a generic thermal or storage plant we may assess. Similarly, wind UCAP values are discounted to 15.6 percent of ICAP.

[2] Note: As further discussed below, these costs are not used in evaluating the cost of our Preferred Plan for North Dakota. See our discussion regarding the North Dakota Plan in Chapter 4: Preferred Plan.

Generic units ICAP values included in modeling are as follows:[3]

- 331 MW gas-fired combustion turbine peaking unit (CT),
- 206 MW gas-fired combustion turbine peaking unit (CT),
- 856 MW gas-fired combined cycle intermediate unit (CC),
- 331 MW energy storage project, with costs and performance comparable to lithium-ion battery technology,
- 750 MW wind project
- 500 MW grid-scale single-axis tracking solar project
- 100 MW distributed solar project

Appendix F2: Strategist Modeling Assumptions & Inputs, provides more detail on Strategist assumptions. Please see Appendix F6: Resource Options, for additional discussion on supply-side resource options included in the analysis.

Customer Programs. Incremental customer programs for DR and EE were included as potential resources in the Strategist model. The derivation of these three DR and three EE "Bundles" are described in Appendix F6.

It is important to note that these Bundles represent generic DSM additions and therefore may not perfectly align with the size and timing of actual DR or EE additions to the system in the future. These Bundles were developed immediately after receiving third party studies for incorporation into modeling, without the benefit of time to develop detailed implementation plans to achieve the levels of DSM in each Bundle. Therefore, for incremental DR resource additions in particular, while the size and timing of the first Bundle generally achieves the ordered 400 MW by 2023, the actual implementation plans which detail the specific size, type, and timing of incremental additions will likely differ. Procurement plans are illustrated in Appendix G1: Demand Side Management.

DER is modeled with base and high adoptions assumptions, using similar levels as provided in our 2018 IDP filing. We discuss our DER forecasts in Appendix F1: Load and Distributed Energy Resource Forecasting.

[3] The cost and performance data for these units are based on consultant's estimates, publicly available third-party data, and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction.

II. SCENARIOS

As noted above, we created 15 scenarios to examine combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We describe key parameters of these scenarios below.

A. Reference Case Scenario

We describe the development of our Reference Case in Chapter 3: Minimum System Needs. The Reference Case (Scenario 1) is an extension of our 2015 Resource Plan, in that all of the baseload units retire at their currently scheduled retirement dates, and serves as our starting point. The approved 1,850 MW wind portfolio that is in progress is included, along with generic wind and solar units added to the plan to ensure that we do not fall below the current level of renewables we have on our system (i.e. a "no going back" portfolio). Additional renewable units are evaluated and optimized in the modeling and added where economic. In the original phases of the modeling, the DR and EE Bundles were evaluated as optimized economic alternatives, as were distributed solar, storage, and thermal CT and CC resources. The Sherco CC unit and owned MEC CC unit were included in the Expansion Plan. Firm peaking resources were included in the plan as needed to maintain the Reliability Requirement criteria.

To determine the optimal strategy regarding the future of the baseload fleet, we developed additional scenarios with varying combinations of baseload resource retirement dates. The resulting system needs were then met with a Strategist model-optimized portfolio of new resources. Internal finance, energy supply, and nuclear subject matte experts worked to develop a robust set of assumptions and potential retirement dates for the baseload units. These input assumptions include: ongoing capital expenditures, O&M expenses and decommissioning and/or life extension costs. We also incorporated the planning level estimates from the MISO Y2 studies performed as part of our Baseload Study that informed our Preferred Plan. See Appendix J1 for more details regarding this study. The scenarios we evaluated can be generally grouped into families, as described below.

B. Early Coal Family

This family of scenarios is designed to evaluate the economics (i.e. revenue requirement impacts) of retiring King and/or Sherco 3 early. We did not study life extension for coal facilities. For the early coal retirement scenarios, the early retirement date for King was assumed to be the end of 2028, and for Sherco 3 the early date was the end of 2030. We chose these retirement dates because they generally allow an orderly and staged transition, with a major coal retirement every two to three years. In the all early coal scenarios, for example, the retirement schedule is Sherco 2 in 2023, Sherco 1 in 2026, King in 2028 and Sherco 3 in 2030.

- Scenario 2 **(Early King)** – King is retired at the end of 2028. Sherco 3 and the nuclear units are unchanged.
- Scenario 3 **(Early Sherco 3**) – Sherco 3 is retired at the end of 2030. King and the nuclear units are unchanged.
- Scenario 4 **(Early All Coal)** – King is retired at the end of 2028, Sherco 3 is retired at the end of 2030, and the nuclear units are unchanged.

C. Early Nuclear Family

This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together, and with the combination of early coal retirements. For the early nuclear retirement scenarios, the early retirement date for Monticello was assumed to be the end of 2026 and for Prairie Island 1 and 2 it was the end of 2024 and 2025, respectively. We chose these retirement dates as we felt they best balanced the need for adequate lead time to enable an early major nuclear retirement with the desire to evaluate retirement scenarios that occur well ahead of the existing retirement dates in the 2030s.

- Scenario 5 **(Early Monticello)** – Monticello is retired at the end of 2026. Coal and Prairie Island is unchanged.
- Scenario 6 **(Early Prairie Island)** – Prairie Island is fully retired by the end of 2025. Coal and Monticello is unchanged.
- Scenario 7 **(Early All Nuclear)** – Prairie Island and Monticello are both retired early per the years above, the coal units are unchanged.
- Scenario 8 **(Early All Baseload)** – All baseload units, including coal and nuclear, are retired early per the years indicated above.

D. Extend Nuclear Family

This family of scenarios is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending operational life by 10 years over the current retirement dates. For the extend nuclear scenarios, the revised date for Monticello was assumed to be the end of 2040 and for Prairie Island 1 and 2 was the end of 2043 and 2044, respectively.

- Scenario 9 (**Early Coal, Extend Monticello)** – All coal was retired at the early dates and Monticello is extended for 10 years. Prairie Island is unchanged.
- Scenario 10 (**Early King, Extend Monticello)** – King was retired at the early date and Monticello is extended for 10 years. Sherco 3 and Prairie Island are unchanged.
- Scenario 11**(Early Coal, Extend Prairie Island)** – All coal was retired at the early dates and Prairie Island is extended for 10 years. Monticello is unchanged.
- Scenario 12 **(Early Coal, Extend All Nuclear)** – All coal was retired at the early dates and both Monticello and Prairie Island are extended for 10 years.
- Scenario 13 (**Extend Monticello)** –Monticello is extended for 10 years. King, Sherco 3 and Prairie Island are unchanged.
- Scenario 14 **(Extend Prairie Island)** – Prairie Island is extended for 10 years. King, Sherco 3 and Monticello are unchanged.
- Scenario 15 **(Extend All Nuclear)** –Both Monticello and Prairie Island are extended for 10 years. King and Sherco 3 are unchanged.

III. FUTURES SCENARIOS AND SENSITIVITIES

To determine how changes in our assumptions impact the costs or characteristics of different plans, we have historically evaluated how the plan responds to changes in individual input assumptions. This testing helps us assess the "robustness" of each scenario in the face of future uncertainty, meaning that we want to test how resilient the scenario is to changes in one or more key assumptions. Generally, if a given plan is extremely sensitive to changes in assumptions, it would not represent a prudent course of action for the Company to pursue, because it would subject our customers to excessive risk. While we believe there is value in evaluating the individual sensitivities, and have provided a comprehensive analysis of those sensitivities in Appendix F3, we took a slightly different approach to stress test our results in this particular Resource Plan.

A. Futures Scenarios

Consistent with the MISO MTEP Process, we adopted a scenario-based planning approach to our sensitivity analysis that we have incorporated for the first time in this Resource Plan. Since many of the input assumption variables in our modeling are correlated, we believe there is more value in looking at a combination of variable sensitivities as opposed to "one-off" sensitivity runs. Evaluating one sensitivity at a time may isolate the impacts of the variable in question, but may not necessarily reflect a realistic future scenario.

We developed four Futures Scenarios, using the 2018 MTEP Futures as guideposts. The first two Futures Scenarios (Base PVSC and Base PVRR) represent our base assumptions, with and without carbon costs, as we have consistently provided this view as part of previous Resource Plans and are required to provide the PVRR view for our North Dakota stakeholders. The High Electrification and High Distributed Solar cases represent our new approach, in which we adjusted multiple sensitivities in each Futures Scenario to assess the combined effect of these changes. While there are certainly many assumptions we could have adjusted, we focused on the four most important variables which include fuel price forecasts, load forecasts (or variables impacting the load forecast like distributed solar), carbon and externality costs, and new resource capital costs. The assumptions made for each Futures Scenario can be seen in Table 5-1 below:

Table 5-1: 2019 Resource Plan Futures Scenarios

Futures Scenario	Description	Gas, Power, Coal Prices	Load Forecast	Carbon & Externality Costs	New Resource Capital Costs
Base Scenario (PVSC)	Base Case with Carbon Costs, Similar to MISO MTEP Continued Fleet Change (CFC) Scenario	Base	Base 50/50	High/High	Base
No Carbon (PVRR)	No Carbon Costs	Base	Base 50/50	**None**	Base
High Electrification & Low Tech Costs (PVSC)	Similar to MISO MTEP Accelerated Fleet Change (AFC) Scenario	**High**	**High Electrification Forecast**	High/High	**Low**
High Distributed Solar Deployment, Low Tech Costs (PVSC)	Similar to MISO MTEP Limited Fleet Change (LFC) Scenario	**Low**	**High DG Solar Forecast & Higher EE Levels**	High/High	**Low**

Note: bolded and underlined parameters indicate assumptions that have been modified from the Base Scenario

For the High Electrification Scenario, we examine a case in which higher load levels are expected to stimulate higher fuel demand and consequently higher overall fuel prices. To construct this Scenario, we used a high electrification forecast provided by E3, informed by their Minnesota PATHWAYS study provided as Appendix P3 to this Resource Plan, to assess the impacts of high load, high fuel price, and a low technology cost environment.

Conversely, for the High Distributed Solar Deployment Scenario, lower load levels driven by higher levels of offsetting distributed solar could reasonably be expected to drive down fuel demand and result in lower overall fuel prices. To construct this Scenario, we used an internally developed high customer adoption based distributed solar forecast to assess the impacts of low load, low fuel price and low technology cost environment. We also forced in all three EE Bundles to further reduce the load forecast and evaluate a future that truly stresses our baseload decision options.

In both the High Electrification and the High Distributed Solar Scenarios, we assumed low new resource capital costs. We believe this is an appropriate assumption to test, because trends have indicated that the market has previously underestimated realized cost reductions in renewables and other new technologies, and we feel this could continue to occur going forward. Likewise, in both these Futures Scenarios, we included carbon and externality costs, consistent with resource planning principles in Minnesota.

Figure 5-2: Peak Demand, Net of EE Impacts, by Futures Scenario (MW)

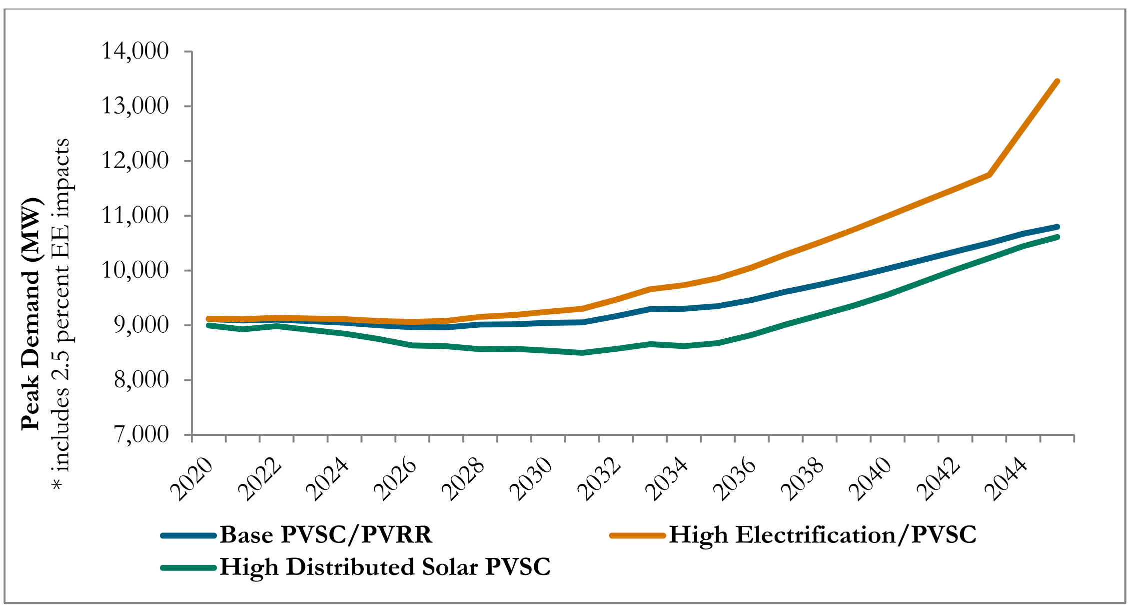


Figure 5-3: Fuel Price Assumptions, by Futures Scenario

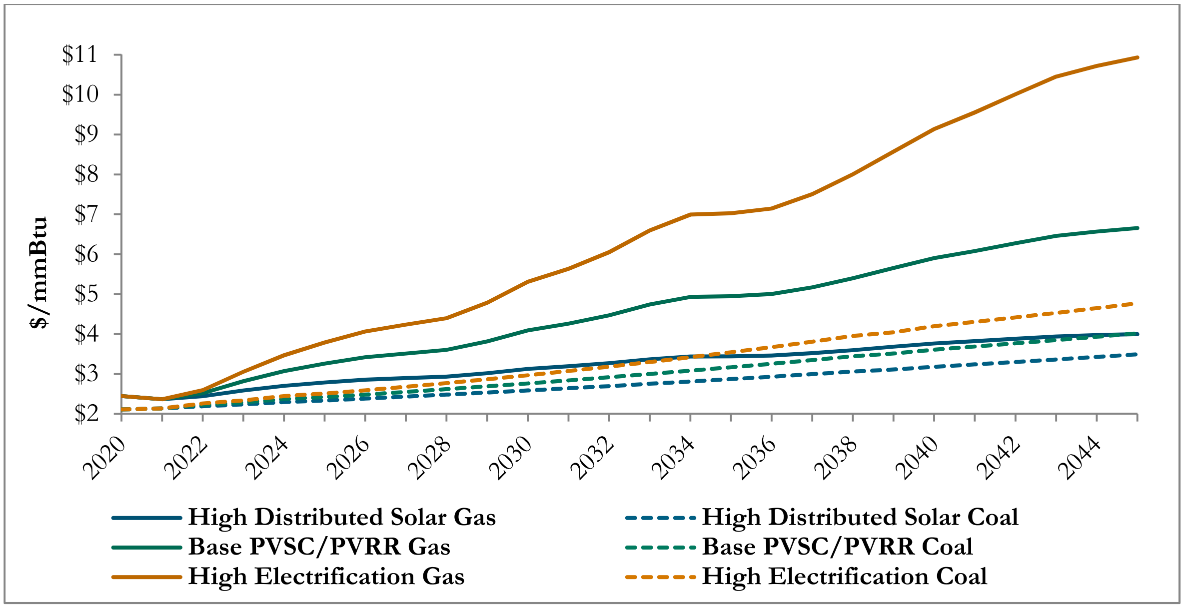


Figure 5-4: New Resource Cost Assumptions, by Futures Scenario ($/MWh; $/kW-mo)

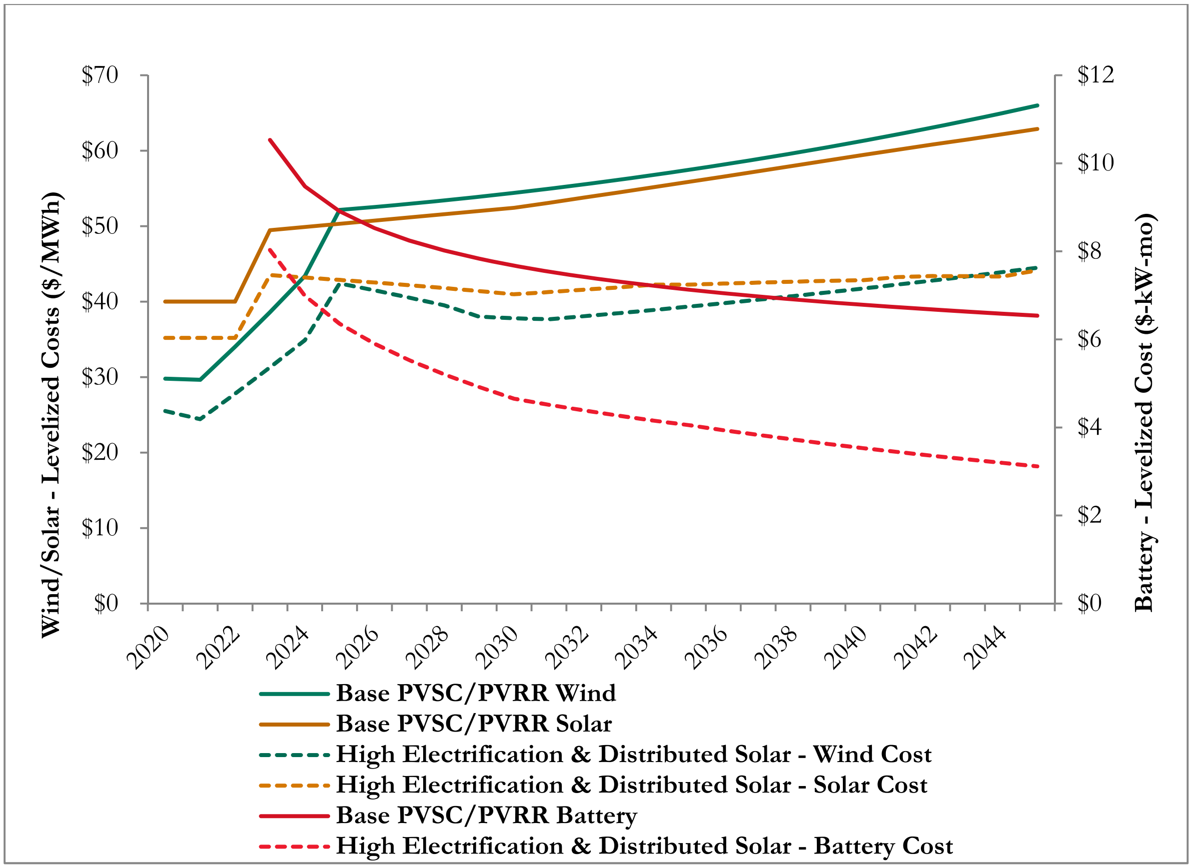
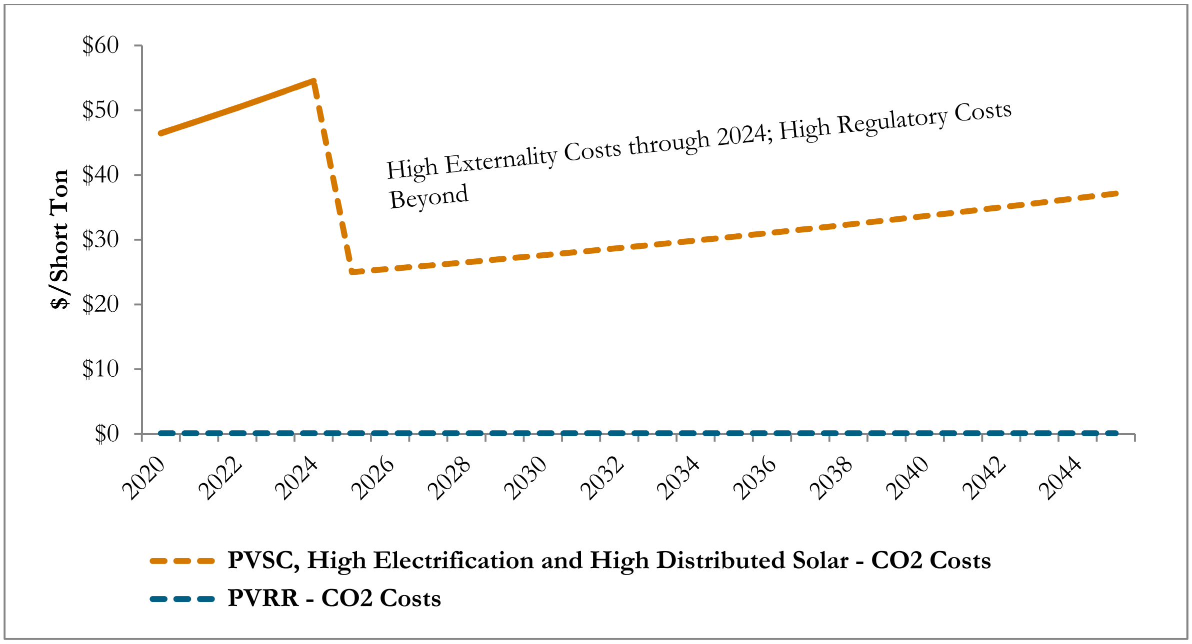


**Figure 5-5: Carbon Emissions Cost Assumptions
($/Short Ton)**



It is important to note that these Futures Scenarios were designed to test the performance of our baseload retirement decisions under plausible future states. These Futures Scenarios are not, however, intended to test which future is overall least cost for our system. We do not have full control over the level of distributed solar or electrification growth on our system, and have no control over variables such as fuel prices and new resource capital costs. As demonstrated in the next section, the Futures Scenario analysis shows that our Preferred Plan baseload decisions to retire all coal by 2030 and extend Monticello are likely to yield customer benefits relative to the Reference Case, even in a future where multiple key assumptions change simultaneously.

B. Traditional Sensitivities

While our primary focus has shifted to Futures Scenarios as opposed to the traditional single sensitivities, we still believe the individual sensitivities provide insights on potential plan performance. Therefore, consistent with previous Resource Plans, we tested the following individual sensitivities. Detailed results for these sensitivities can be found in Appendix F3.

- *Load.* The low load sensitivity includes high customer adoption-based DER growth and higher EE savings (i.e. it includes all three EE Bundles), which reduces load. The high load sensitivity includes high electrification load.

- *Fuel Price/Market Costs.* High and low price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast starting in year 2022.
- *CO_2 Values.* To examine the effect of CO_2 pricing, we tested high and low cost sensitivities. We also performed a sensitivity evaluating no CO_2 cost. The PVSC Base Case CO_2 values are based on the high externality cost values for CO_2 as determined by the Minnesota Commission through 2024.[4] The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs.[5] Below is the list of carbon sensitivities.
    - Low Externality
    - Low Externality, Low Regulatory
    - Mid Externality, Mid Regulatory
    - High Externality
    - PVRR, or No Externality or Regulatory
- *Externalities.* Criteria pollutants values are derived from the high and low values for each of the three geographic locations in the Minnesota Commission Order,[6] with existing plants assigned the appropriate area and generic units assigned to "rural." The midpoint externality costs are the average of the low and high values. The high, low and midpoint externality costs are used in conjunction with the CO_2 sensitivities described above.
- *Resource Costs.* For wind, solar and battery energy storage we use NREL's *Annual Technology Baseline* (ATB) 2018 report to provide high and low technology cost sensitivity inputs. For wind and solar, we use the costs projected by the ATB directly. For batteries, we take a slightly different approach. Low and high battery costs are based the percent difference in the NREL ATB base, low and high battery cost forecasts, with this percent difference applied to the Company's base battery cost forecast. We did not adjust capital costs for thermal resources such as the generic CC or CTs, so all scenarios include our base cost assumptions for those resources.
- *Markets Sales Off.* As previously discussed, we assume that markets are "on" for each scenario. The "markets off" sensitivity represents a view in which we

[4] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.) at 31.
[5] Minnesota Commission Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Docket Nos. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018) at 12.
[6] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

cannot access the market to sell energy outside our system.

IV. STRATEGIST ANALYSIS AND RESULTS

After identifying the scenarios and sensitivities for analysis, we used Strategist to identify the expansion plans for each of the 15 primary scenarios, and their resulting cost and emissions impacts. We faced a number of challenges as we tested the full capabilities of the model and attempted to be responsive to stakeholder requests to include a robust set of supply-side and demand-side resource options for consideration. As described below, we undertook an extensive process which attempted to balance the inclusion of a comprehensive set of resource options with the model's limitations, to arrive at a plan that demonstrates a high level of diligence and investigation. This analysis was performed iteratively in several rounds, as we refined the process and results, with each round informing modeling parameters for subsequent rounds. Achieving an appropriate balance between resource options and modeling runtime efficiency required the following adjustments, which are described in more detail in the sections below:

- Removal of our generic distributed solar resource options, with the understanding that if future DG solar growth exceeds our embedded assumptions, it can simply displace utility scale solar additions identified in the Preferred Plan.
- Shortening the modeling period to end in 2025, from the original 2057 end date.
- Testing EE and DR selection via optimizations, evaluating different combinations of the three EE and three DR Bundles for cost effectiveness, and then locking the optimal mix of Bundles in final optimizations.
- Manually inserting CT additions as a proxy placeholder for the firm, dispatchable resource needs driven by the Reliability Requirement. In reality, because these additions happen in the post-2030 timeframe, we expect the need will be met by a combination of firm dispatchable resource options. These may include battery storage, pumped hydro, DR, natural gas, and/or others.

A. Initial Full Optimization

In the first initial round of modeling, all technology alternatives (wind, solar, distributed solar, storage, DR, EE, CC, CT) were made available to the model and we developed a fully optimized expansion plan for each scenario through the end of the available years in Strategist (2057). We found that this stretched the capabilities of the Strategist tool. Due to the large number of alternatives, these runs took a significant amount of time to complete; on average, five days of processing time per scenario. Further, the results were significantly truncated.[7] In these initial plans, no DR, EE, or distributed solar alternatives were selected for any of the scenarios. Although this set of initial runs was not reliable enough for drawing final conclusions, due to the truncation issues, we identified several refinements for the next round of modeling.

First, when comparing utility-scale solar and distributed solar, the model did not select any distributed solar. We reviewed the modeling data for these two alternatives and it was clear that, because both utility-scale and distributed solar have identical capacity accreditation[8] values and similar capacity factors, the model would only ever select the lower cost utility-scale solar. For modeling purposes, therefore, we removed distributed solar from the optimization in order to improve model runtime and reduce the number of truncated results. We note that this does not imply distributed solar is not a resource we anticipate will be added to our system – only that from a modeling perspective, distributed solar will not appear as cost-effective relative to utility-scale solar in the modeling process, and retaining both types of resources in the model for future runs would reduce the quality and runtime of the modeling process. As we have explained, any growth in distributed solar we experience on our system beyond what is in our embedded forecasts will simply serve to displace some of the utility-scale additions identified in our Preferred Plan.

Truncation challenges also informed the duration through which we modeled our plans. While our initial runs experienced truncation issues fairly early (beginning in the late 2020's), the further out we attempted to optimize portfolios, the more truncation occurred and the slower the simulation became. Based on this observation, we determined it was prudent to shorten the modeling period, using 2045 as the end year rather than 2057. We believed that this, in combination with adding 10 years of "end effects" in the modeling, would inform plans through the planning period (2020-2034) that were more robust and valid than the longer simulation would provide. Additionally, the availability, cost and performance assumptions for technologies become increasingly subjective far into the future, and we would not adequately account for new technologies that may develop within that timeframe.[9] Thus the results of modeling in that extended period would not be particularly robust and would likely misstate the resource mix and cost required to

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[7] Truncation occurs when the Strategist model has more viable plans for a given year than the internal memory is able to store. The total collection of plans is sorted by accumulated cost up to that year, and the highest cost plans are discarded and not analyzed further. The Company's model is set to a maximum of 2,500 saved plans per year.
[8] I.e. Effective Load Carrying Capability, or ELCC.
[9] We note that an independent analysis from consultant E3 highlighted similar concerns and also conducts expansion plan modeling to 2045.

meet the Company's longer term vision of 100 percent carbon-free energy by 2050.

Further, including the DR and EE Bundles in full model optimizations proved to be a significant challenge for the Strategist model runtime efficiency. Given that the initial full optimizations resulted in no DSM being selected, we decided to pursue an alternative modeling path. For the next round of modeling, the first DR and the first EE Bundle were forced into the plans to test if "seeding" the model with these Bundles would lead to the second or third Bundles being chosen within the economic optimization.

B. Revised Targeted Optimization

The model revisions discussed above resulted in a somewhat improved modeling process, shortening runtimes and reducing truncation. However, the second round of modeling still took over two days per simulation, and displayed significant truncation, such that we determined additional refinements were needed. This process did, however, help us derive more information from our model runs that informed the final stages of the modeling process.

First, in almost all 15 scenarios, once the first DR and EE Bundles were forced in, the second EE Bundle was selected economically. No additional DR was selected. This result indicated that there was indeed a modeling bias (most likely due to truncation) that prevented selection of DR and EE, as defined by the Bundles, in the fully optimized results. We concluded that some other method of "manual" testing would be necessary to determine these resources' true cost-effectiveness.

Additionally, some of the scenario outcomes in this revised modeling process relied almost entirely on non-dispatchable or use-limited resources (wind, solar, storage) for the full capacity expansion plan. At this point, resource planning consulted with operations and engineering, and worked together to develop and implement a modeling element that would ensure the portfolio resulting from each scenario retained sufficient firm dispatchable generation to reliably serve customer capacity and energy requirements. We describe the Reliability Requirement in Appendix J2.

To incorporate the Reliability Requirement into the modeling, we added firm dispatchable load supporting resources, represented currently with CT resources as a proxy, to the expansion plan in specific years[10] to ensure the portfolio maintained the minimum level of firm dispatchable, load supporting resources as defined by the Reliability Requirement. Given the manual addition of firm dispatchable resources,

[10] Applicable years vary by scenario.

we also reduced the number of new resource alternatives available in certain years to further improve model run times. We believe this did not sacrifice or reduce the model's ability to find optimal solutions for the expansion plan. As an example, the large CC unit option was removed as an alternative in years where the incremental capacity need relative to the previous year was small. This targeted "pruning" of alternatives yielded faster run times and less truncation.

Accounting for all the aforementioned factors, we repeated scenario modeling while including: (1) the Reliability Requirement, (2) the targeted resource "pruning" and (3) one DR and one EE Bundle forced in, while still allowing the incremental DSM Bundles to be selected in the optimization. The second EE Bundle was almost always selected, while no additional DR was selected. Additionally, early coal retirement and nuclear extension scenarios emerged as potential preferred options, as they showed favorable PVSC and PVRR, when compared to other scenarios.

C. Energy Efficiency and Demand Response Analysis

In the next phase of modeling, we worked to refine the DR and EE analysis to identify the most cost effective Bundle combinations. After reviewing initial modeling results, we were confident that two Bundles of EE would likely be selected across all scenarios but wanted to conduct an additional round of tests to confirm. Given we observed strong PVSC and PVRR performance of early coal retirement and extended nuclear scenarios in previous rounds of modeling, we initially conducted DR and EE testing using Scenario 9 (Early King and Sherco 3 retirement with Monticello Extension) and Scenario 10 (Early King retirement with Monticello Extension) as a test. To adequately analyze the Bundles, we developed PVSC and PVRR matrices by selecting a scenario and performing optimizations that included each permutation of the three DR and three EE Bundles. This manual process eliminated the potential for DR and EE truncation, thus allowing us to conduct a robust analysis of each option.

We show results for Scenario 9 as an example below, and note that in both cases the 0 DR/2 EE combination returns the lowest PVSC and PVRR results.

Table 5-2: Scenario 9 (Preferred Plan) DR and EE Cost Effectiveness Analyses ($2019 millions)

PVSC				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$48,486	$48,203	$48,502	$48,745
1 EE	$45,390	$45,670	$45,947	$46,152
2 EE	$45,173	$45,512	$45,726	$45,910
3 EE	$45,847	$46,166	$46,389	$46,596

PVSC Deltas (as compared to 0 DR/2 EE)				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$3,313	$3,030	$3,329	$3,572
1 EE	$217	$497	$774	$979
2 EE	-	$339	$553	$737
3 EE	$674	$993	$1,217	$1,423

PVRR				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$40,029	$40,216	$40,478	$40,653
1 EE	$37,657	$37,910	$38,182	$38,344
2 EE	$37,476	$37,784	$37,925	$38,143
3 EE	$38,374	$38,589	$38,802	$39,009

PVRR Deltas (as compared to 0 DR/2 EE)				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$2,554	$2,741	$3,003	$3,177
1 EE	$181	$435	$706	$869
2 EE	-	$308	$450	$668
3 EE	$899	$1,113	$1,327	$1,533

Based on this result, subsequent model runs for the baseload analysis locked in 0 DR Bundles and two EE Bundles, and removed consideration of the remaining DR and EE Bundles from the optimization process. As discussed further in Section V and elsewhere in this Resource Plan however, we ultimately included the first Bundle of DR as part of the Expansion Plan.

D. Final Scenario Analysis

The last round of baseload scenario modeling incorporated the results of the previous rounds into defining and executing a final analysis, which we used to draw conclusions on the relative economics and operational performance of the 15 baseload scenarios. For the final model runs, two EE Bundles were manually added to the plans, and the remaining Bundles were removed from the optimization, per our previous findings that they would not be selected. The Reliability Requirement was included as a constraint, and the number and timing of alternatives were reduced as previously described, in order to improve model run performance without sacrificing the ability to effectively optimize remaining resource options. We then created expansion plans for all 15 scenarios, using PVSC assumptions, and completed the full set of sensitivities.[11]

[11] Minn. Stat. § 216B.2423

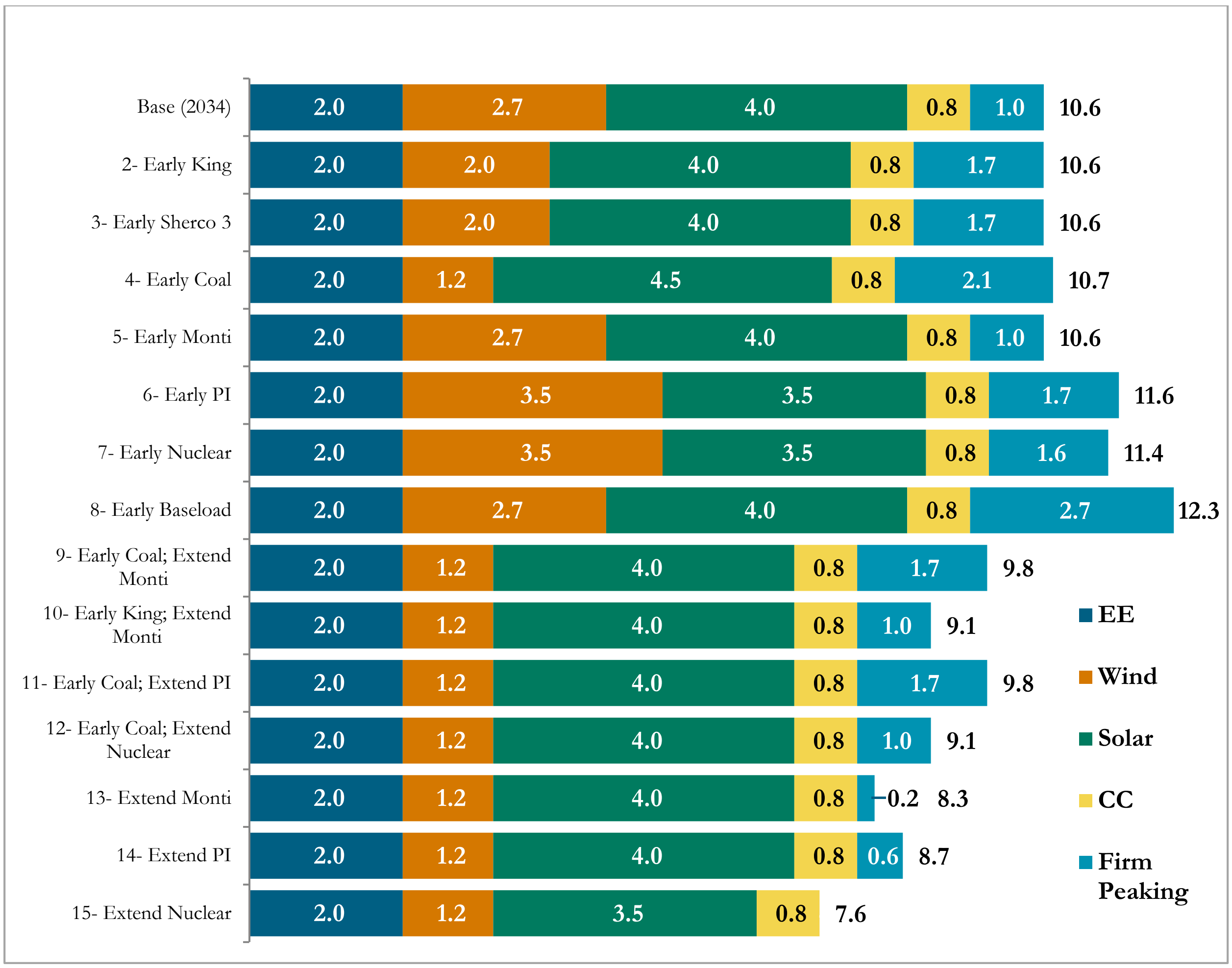
E. Modeling Results and Conclusions

Completing baseload scenario runs, as described above, allows us to examine Scenario outcomes side-by-side, to evaluate their benefits and drawbacks. Among other factors, we examine each Scenario's resource expansion profile and carbon emissions outcomes, present value costs, and several indicators of risk.

1. Capacity Additions and Emissions Reductions

The cumulative expansion plan additions through the planning period for the 15 scenarios are shown below in Figure 5-6.

Figure 5-6: Expansion Plans by Scenario
(GW, Cumulative Nameplate Capacity Resource Additions by Fuel Type)

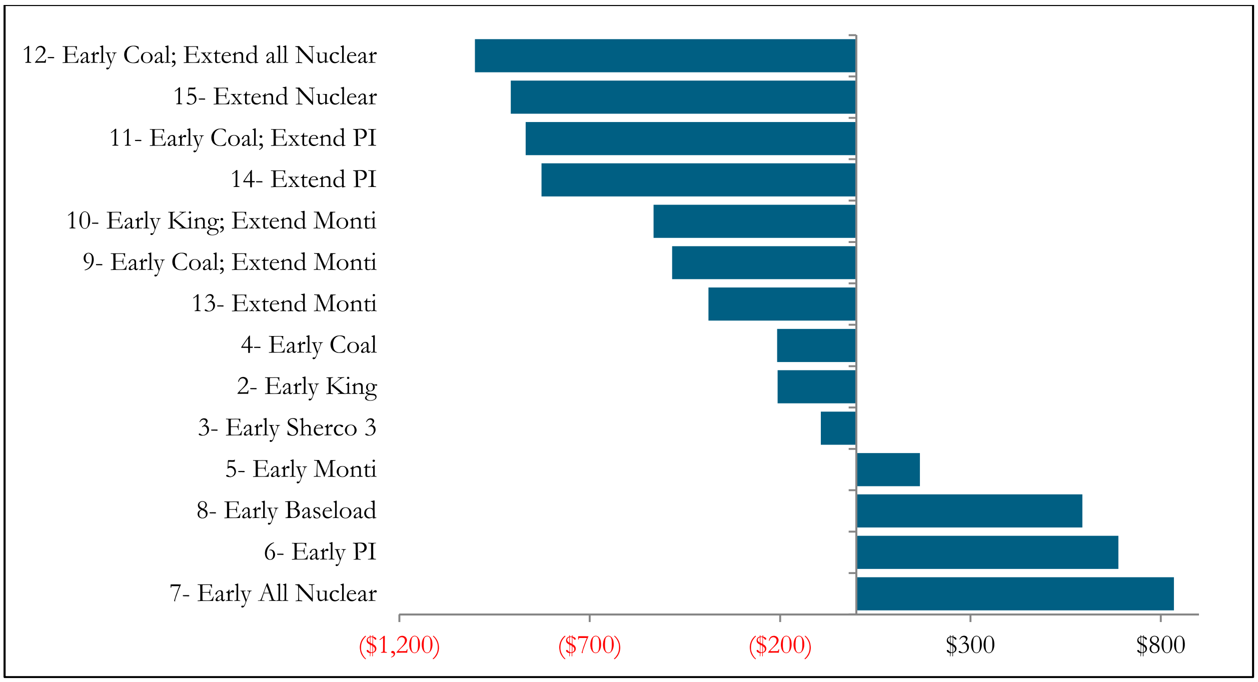


As the 80 percent carbon emissions reduction target was included as a modeling parameter, all the scenarios achieve this goal and remain under the emissions threshold from 2030 throughout the planning period. There is minimal variability between Scenarios on this measure, other than the timeframe in which they first reach 80 percent reduction levels.

2. *Present Value Costs*

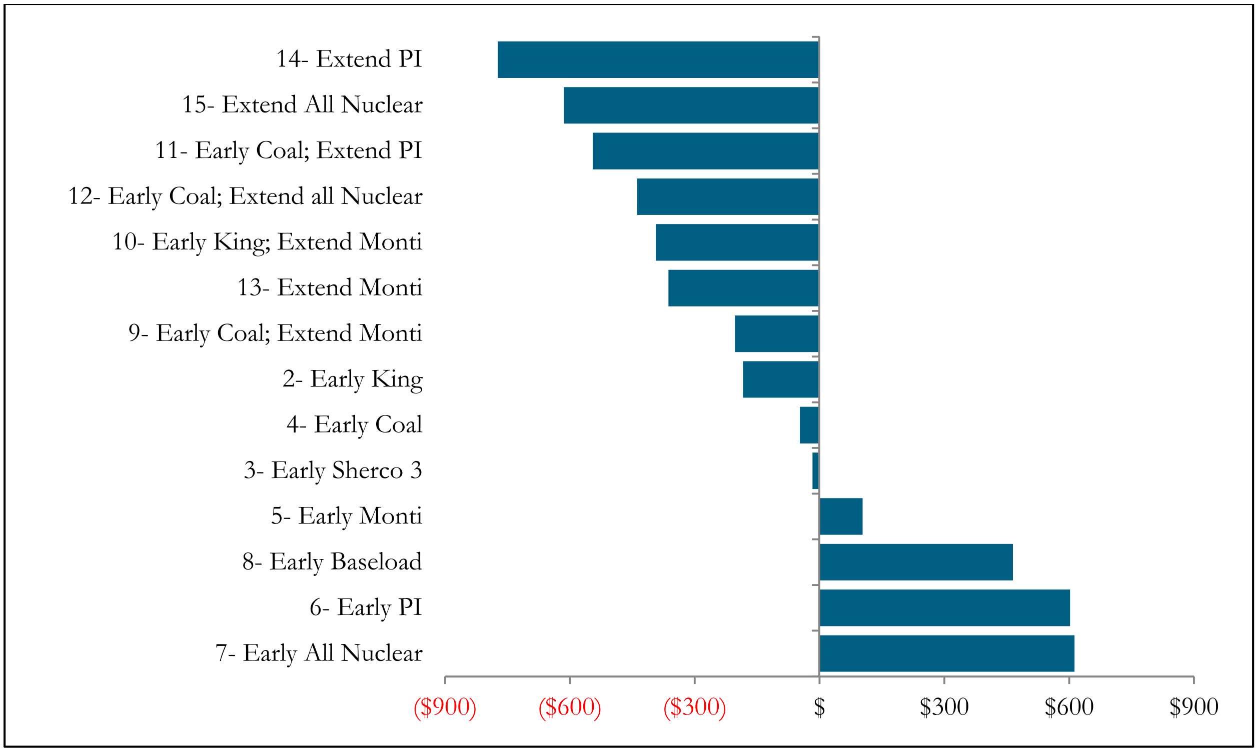
In general, plans that favored early coal retirements and nuclear extensions were the lowest cost plans, both in terms of PVSC and PVRR. The results for the 15 scenarios from the final modeling runs are shown below in Figures 5-7 and 5-8. The figures show the net present value (NPV) delta of modeled costs compared to Scenario 1 (the Reference Scenario), with negative values representing customer savings relative to the Reference Scenario and positive values representing increased costs.[12]

Figure 5-7: Scenario PVSC Deltas from Reference Case ($2019 millions)



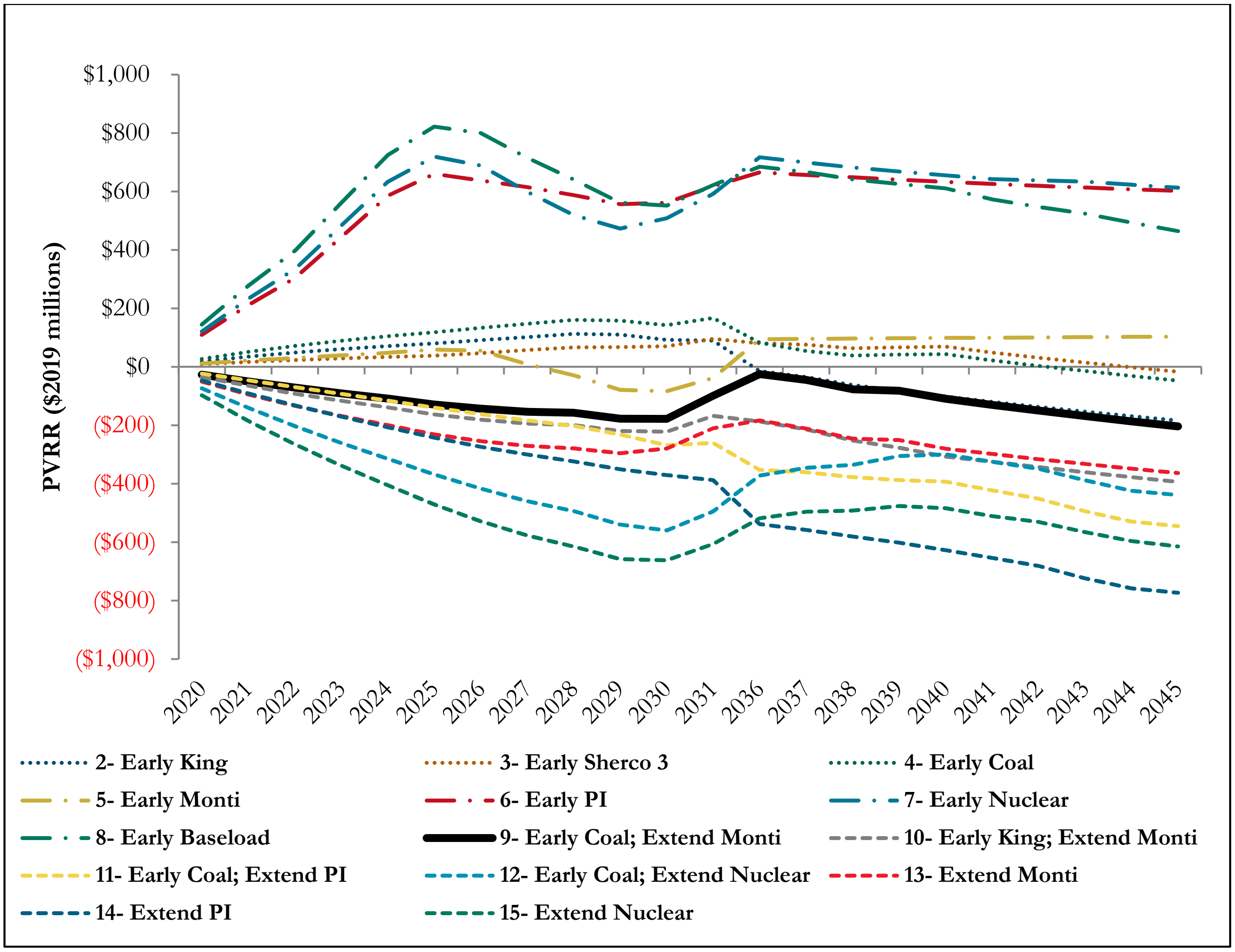
[12] Note that these PVRR and PVSC deltas shown depict NPV for 2020-2045.

Figure 5-8: Scenario PVRR Deltas from Reference Case ($2019 millions)



In addition to evaluating the total NPV of each scenario, we also examine the timing of the relative costs and benefits. Examining NPV over a time series helps us make relative comparisons of changes in costs or benefits at key "transition points" of the plans (such as retirement or extension dates, significant renewable additions, etc.). The cumulative total PVRR costs or savings for each of the scenarios are shown below in Figure 5-9. Each line on the chart illustrates the running total of the annual PVRR costs or benefits by year for a specific scenario, compared to the Reference Case. The end point of the lines in 2045 corresponds to the final PVRR deltas shown in Figure 5-8 above.

Figure 5-9: Cumulative PVRR Cost or Savings Deltas by Scenario, Compared to the Reference Plan ($2019 million)



In addition to PVSC and PVRR, the Company completed sensitivity analyses for all 15 scenarios. The results of these analyses are shown in Appendix F3.

3. Additional Risk Metrics for Baseload Scenario Evaluation

While present value costs are one factor we use to inform our Preferred Plan, we also consider other factors and elements of risk exposure for each potential Scenario. Consistent with the Resource Plan objectives presented in Chapter 4, we evaluated each scenario with regard to achieving our cost, environmental, risk and reliability goals. It is essential that our Preferred Plan meets our carbon reduction goals while also ensuring that the system remains reliable and the plan remains affordable for customers. Likewise, it is important we evaluate various risks, because forecasting into the future is inherently uncertain and we want to ensure our selected Plan remains robust, even if some key factors change. We describe the objective risk measures we used to evaluate the scenarios in Table 5-3 below.

Table 5-3: Scenario Modeling Portfolio Risk Metrics

Objective	Metric	Definition
Cost	Base PVRR and Base PVSC	Traditional NPV measure of total 2020-2045 PVRR or PVSC costs to determine least cost plan. Plans showing cost savings are preferred.
	Worst Case Futures Scenario Cost	Measure of worst case potential cost outcomes across the four Futures Scenarios so provides insight into plan cost risk. Plans still showing cost savings in worst case Futures Scenario are preferred.
Risk	Energy Risk	Measures the absolute value of average annual total market interaction (purchases plus sales plus dump energy) associated with each plan, to assess market energy risk exposure. Plans with lower market energy exposure are preferred.
	Capacity Risk	Measures average annual net capacity position associated with each plan, to assess market capacity risk exposure. Typically, plans with lower net capacity positions are considered favorable, and our rankings reflect that. However, we also take into account certain factors that are specific to this Resource Plan, which affect the weight we place on this metric. These are discussed further below in Section V.
Environmental	Carbon Emissions Reduction	All plans achieve acceptable levels of carbon reduction, as a result of including an 80 percent carbon reduction (relative to 2005 levels) constraint in modeling.
Reliability	Firm, Dispatchable Resource to Peak Load Ratio	All plans achieve acceptable levels of reliability, measured by the amount of firm, dispatchable resources available, as a result of including the Reliability Requirement in modeling.

As noted, all scenarios meet the environmental and reliability objectives, given these targets are included as constraints in our modeling. Thus, our Scenario evaluation focuses on the cost and risk objective metrics noted above.

V. PREFERRED PLAN SELECTION AND ASSESSMENT

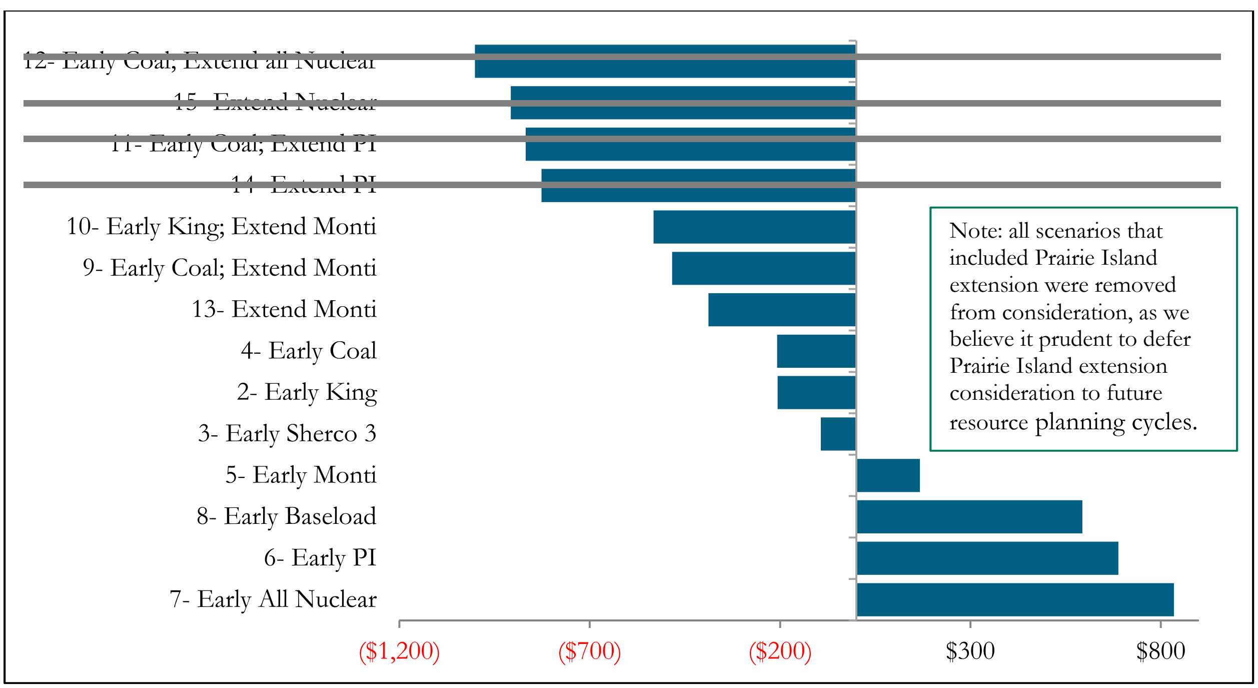
As described previously in this Chapter and in Chapter 4, we evaluated the PVRR and PVSC results of our 15 baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the Preferred Plan. Based on these outcomes, we selected baseload Scenario 9. Our plan charts the path toward achieving ambitious carbon reduction goals, reflects substantial stakeholder input and consensus, and ensures reliability and affordability for our customers. The baseload aspects of this plan include an early King retirement in 2028, Sherco 3 early retirement in 2030 and extension of our Monticello nuclear facility to 2040. We also took into account additional considerations regarding DR when finalizing the Preferred Plan. We discuss more detail regarding how we selected and evaluated our Preferred Plan below.

A. Baseload Study Analysis Results

From a modeling perspective, the PVSC and PVRR results are primary indicators of the various scenarios' economic favorability. Figures 5-8 and 5-9 shown above indicate that the nuclear extension scenarios paired with early coal retirements yielded the most attractive customer value relative to the Reference Case.

We note that while Baseload Scenario 9 was not the least cost of our 15 scenarios, several lesser cost scenarios included an extension of Prairie Island's operating license. However, as discussed previously, Prairie Island's license does not expire until the 2033-3034 timeframe just outside the planning period, and we believe there is risk avoidance value in deferring a decision on Prairie Island extension until a future Resource Planning process. As a result, we eliminated from consideration cases that include a Prairie Island extension, as shown below.

Figure 5-10: Scenario PVSC Deltas from Reference Case, PI Extension Cases Eliminated ($2019 millions)



After screening out the baseload scenarios that include Prairie Island extension, we evaluated the remaining scenarios using the cost and risk metrics discussed previously, including savings or costs achieved in a "worst-case" Futures Scenario, and average energy and capacity exposure. Of the remaining baseload scenarios available for selection, Scenarios 9 (Early Coal; Extend Monti), and 10 (Early King; Extend Monti) achieve the most favorable risk profile overall.

Further, Minn. Stat. § 216B.2422, subd. 2(c) requires that we "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." The Preferred Plan (Scenario 9 - Early Coal; Extend Monti) satisfies the statute's first requirement (50 percent of energy needs from conservation or renewables) because it is economically optimized and meets approximately 64 percent of energy needs with renewables and conservation. Our baseload scenario analysis satisfies this statute's second requirement (75 percent of energy needs from conservation or renewables), as Scenario 4 (Early Coal) yields the least cost plan for meeting at least 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources. Because this scenario does not include a nuclear extension, it enables greater levels of renewable additions than the Preferred Plan that meet or exceed the 75 percent threshold.

B. Early Retirement of Sherco 3 by 2030

Excluding the Prairie Island extension scenarios, Scenarios 9 and 10 become the optimal least cost options. Both Scenarios 9 and 10 assume an early King retirement and Monticello extension; however, Scenario 9 includes an early Sherco 3 retirement while Scenario 10 does not. Both Scenarios are beneficial on a PVSC and PVRR basis, and are the most resilient of the remaining scenarios to the potential worst case evaluated, continuing to maintain customer benefits relative to the Reference case.

Given the proximity of overall customer savings and risk considerations between Scenario 9 and 10, we ultimately considered which case would fit best with our strategic objectives and our understanding of stakeholder interests. We selected Scenario 9 as our Preferred Plan, which includes the retirement of all remaining coal units. Scenario 9 provides the best fit for our carbon goals and helps mitigate the potential for regulatory or legislative action around carbon costs or carbon reduction levels. Further, general market trends toward increasing levels and decreasing costs of renewables, low natural gas prices, the need for more flexible resources, and other factors are expected to make it more and more difficult for coal resources to operate in an efficient and economic manner beyond 2030. Finally, our interactions with customers, stakeholders, and shareholders alike have shown increasing interest in achievement of carbon reductions and other environmental solutions. From a financial risk perspective, we believe it is beneficial for the Company to reduce carbon risk exposure, and we view transitioning our generation fleet away from coal assets is one of the best ways to achieve that goal.

C. Demand Response Adjustment to Scenario 9

As noted previously, the model optimization exercise did not select any of the DR Bundles provided as options. However, the Order approving our last Resource Plan included direction to add 400 MW of incremental DR resources. Therefore, the final step in developing our Preferred Plan was to include DR Bundle 1 as part of Scenario 9. This addition increases our net long capacity position, where after 2025, our position remains long by a range of 500-1,000 MW through the remainder of the planning period. As mentioned previously, we typically view a long capacity position as less favorable; however, we believe this is an acceptable path forward given alignment with our risk mitigation planning objective, discussed further below.

D. Futures Scenarios Results

As previously discussed, a final step in our analysis process evaluated the performance of the Preferred Plan under the Futures Scenarios. Table 5-4 below provides a summary of the Futures Scenario results. Under all of these Futures Scenarios, the Preferred Plan provides savings relative to the Reference Case,[13] which suggests that the Plan is robust under a range of potential future conditions.

Table 5-4: Preferred Plan NPV Savings under Different Futures Scenarios ($2019 millions)

	Base PVSC	Base PVRR	High Electrification Scenario PVSC	High Distributed Solar Scenario PVSC
Delta	***(461)***	***(203)***	***(81)***	***(51)***

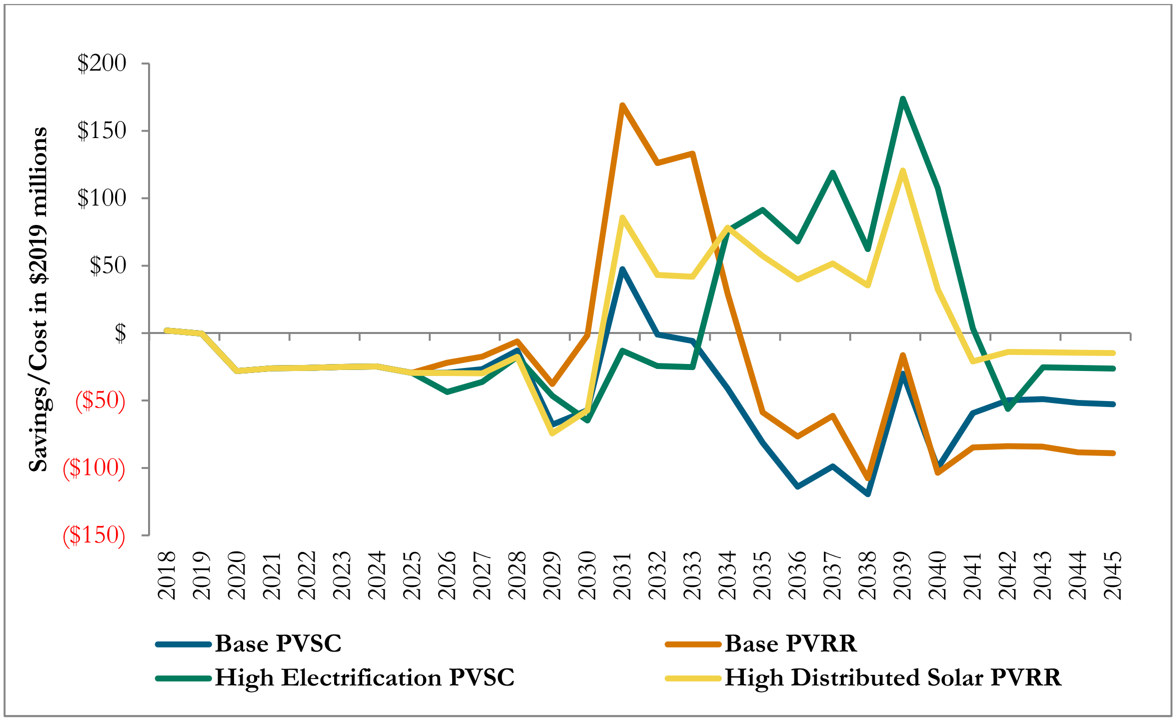
As demonstrated in the baseload scenario analysis and in Table 5-4, the Preferred Plan yields customer value of $203 million in the base PVRR and $461 million in the base PVSC scenarios. Early coal retirements paired with the Monticello extension yield

[13] Note: Each NPV result compares the Preferred Plan with Future Scenarios assumptions applied to the Reference Case with those same assumptions applied.

benefits to customers particularly when carbon costs are included. In both the High Electrification and the High Distributed Solar Futures Scenarios, customer value is marginally reduced from the Base PVRR and PVSC scenarios with $81 million of savings in the High Electrification Scenario and $51 million of savings in the High Distributed Solar Scenario.

As shown in Figure 5-11 below, the Preferred Plan consistently results in customer savings relative to the Reference Case in all Future Scenarios through 2030. At that time, however, the Base PVSC and PVRR scenarios diverge from the High Electrification and High Distributed Solar Scenarios mainly in the 2030 timeframe. A number of factors impact the annual deltas in these Scenarios and drive the divergence. Assumed low new resource capital costs in the Electrification and High Distributed Solar Scenarios likely functions as the biggest driver in upward cost pressure on the Preferred Plan in the 2030s, as in those Scenarios Monticello can be replaced with cheaper renewables. Even under these conditions,, however, the results demonstrate that over the entire planning period and across multiple Futures Scenarios, the Preferred Plan provides overall customer savings relative to the Reference Case. This demonstrates that the Plan is robust and beneficial to customers, yielding savings under a host of potential future conditions.

Figure 5-11: Preferred Plan Annual Costs or Savings Compared to the Reference Case, by Scenario ($2019 millions)



The expansion plans for the Preferred Plan under all of the Futures Scenarios analyses are provided below. In the High Electrification Scenario, higher load growth drives incremental solar and firm dispatchable resource additions above what is included in the Base PVSC/PVRR expansion plans. Specifically, the High Electrification Scenario yields an additional 1,000 MW of solar and 748 MW of firm dispatchable additions. In the High Distributed Solar Scenario, utility-scale solar is displaced by incremental distributed solar, as well as additional EE resources, per the inclusion of the third EE Bundle. Total large solar additions are decreased from 4,000 MW in the base scenarios to 2,500 MW total in the High Distributed Solar Scenario.

Table 5-5: Preferred Plan Base Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	**4,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-6: High Electrification Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	500	500	0	500	**5,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	374	0	606	374	374	748	**2,476**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-7: High Distributed Solar Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	0	500	500	0	0	500	500	0	0	**2,500**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	151	171	152	174	186	189	202	207	203	185	183	181	171	167	166	**2,687**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	166	9	11	9	14	93	19	127	27	62	64	67	70	72	**964**

For simplicity, the table below shows cumulative expansion plan additions by resource type. It is important to note that while DR, EE and battery storage are reflected as separate categories, and no incremental additions for these resources are shown, they would be considered to fill any firm dispatchable needs identified in the expansion plans. Similarly, evolving economics and value could also shift the mix of wind and solar additions.

Table 5-8: Cumulative 2020-2034 Additions by Resource Type and Scenario (MW)

	Base Preferred Case	High Electrification	High Distributed Solar
Large Scale Solar	4,000	5,000	2,500
Battery	0	0	0
CC	835	835	835
Firm Dispatchable	1,728	2,476	1,728
DR	542	542	542
EE	2,041	2,041	2,687
Wind	1,202	1,202	1,202
Distributed Solar	442	442	964

E. Preferred Plan Benefits

We believe our analysis supports selection of Scenario 9, including the early retirement of all of our coal resources by 2030 and extension of Monticello nuclear facility to 2040, as our Preferred Plan. While all of our scenarios meet the carbon goal and Reliability Requirement we established, we believe cost and risk considerations elevate Scenario 9 above the rest as an appropriate path forward.

1. Cost

As demonstrated in our modeling analysis, the Preferred Plan achieves customer value, not only under the our Base PVSC ($461 million) and PVRR ($204 million) analysis but also under more challenging future conditions as evidenced in our High Electrification ($81 million) and High Distributed Solar ($51 million) Futures Scenario analysis. In addition, the Preferred Plan yields customer value under all of the individual sensitivities run, even in the Futures Scenario that results in the worst case customer savings outcome (High Distributed Solar Scenario). Lastly, from a customer rate impact perspective, the Preferred Plan results in annual rate increases of just over one (1) percent, which is below the rate of inflation.[14] Altogether, we believe the Preferred Plan delivers tangible customer savings while taking industry-leading steps towards a carbon free future.

2. Risk

In addition to beneficial cost outcomes, the Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The Plan incorporates significant capacity additions to replace retiring resources, consisting of a diverse portfolio of DSM, nuclear extension, solar, wind, and firm dispatchable resource additions. Ensuring we do not become too dependent on a single fuel source mitigates risk. In addition, deferring a decision on a potential Prairie Island license extension affords us additional flexibility to reevaluate in future resource planning cycles, as technology costs and other key assumptions can change quickly.

We also evaluate factors such as energy market exposure and portfolio length. All of our baseload scenarios show high levels of market interaction, driven in part by significant renewable additions; but our selected Plan minimizes them relative to other scenarios and attempts to carefully balance and pace renewable additions with other resources. Further, we typically try to achieve a closer supply-demand balance than

[14] As noted in Chapter 4: Preferred Plan and discussed further in Chapter 6: Customer Rate and Cost Impacts

any of our baseload scenarios offer, although the 500-1000 MW of length in any scenario is relatively minimal compared to our overall system. We believe our Preferred Plan's portfolio length is warranted at this time, however, and creates an effective hedge for our customers against two key risk factors:

- *Capital Investment Wind Down At Retiring Plants.* The retirement of all 2,400 MW of our coal assets, in addition to a few other units by 2030 exposes our customers to some risk as we wind down operations and reduce capital spend at these plants. In the event of an early outage, excess capacity will give us the option to flex the retirement dates as needed if we find that a capital investment is not in our customers' best interests at that time.
- *Renewable and Use-Limited Resource Capacity Accreditation.* Solar capacity accreditation is assumed at 50 percent credit in all years of our modeling. We expect this to change as MISO changes its approach to forward capacity accreditation – recognizing that as solar penetration increases in the footprint, the accredited value of solar will decline. The same also applies for use-limited resources like DR. We discuss this emerging MISO recognition in the Baseload Study provided as Appendix J1, in conjunction with the Reliability Requirement in Appendix J2, and in discussion of our Supporting Infrastructure – Transmission & Distribution, provided as Appendix I.

VI. CONCLUSION

Considering the above we believe our modeling and analysis fully supports selection of the Preferred Plan, and strikes a strong balance in meeting our planning objectives, in service of our customers' needs. The plan sets us on a path to deliver tangible savings to our customers, while transitioning our system to meet both our 2030 carbon reduction objectives and longer term carbon-free goals.

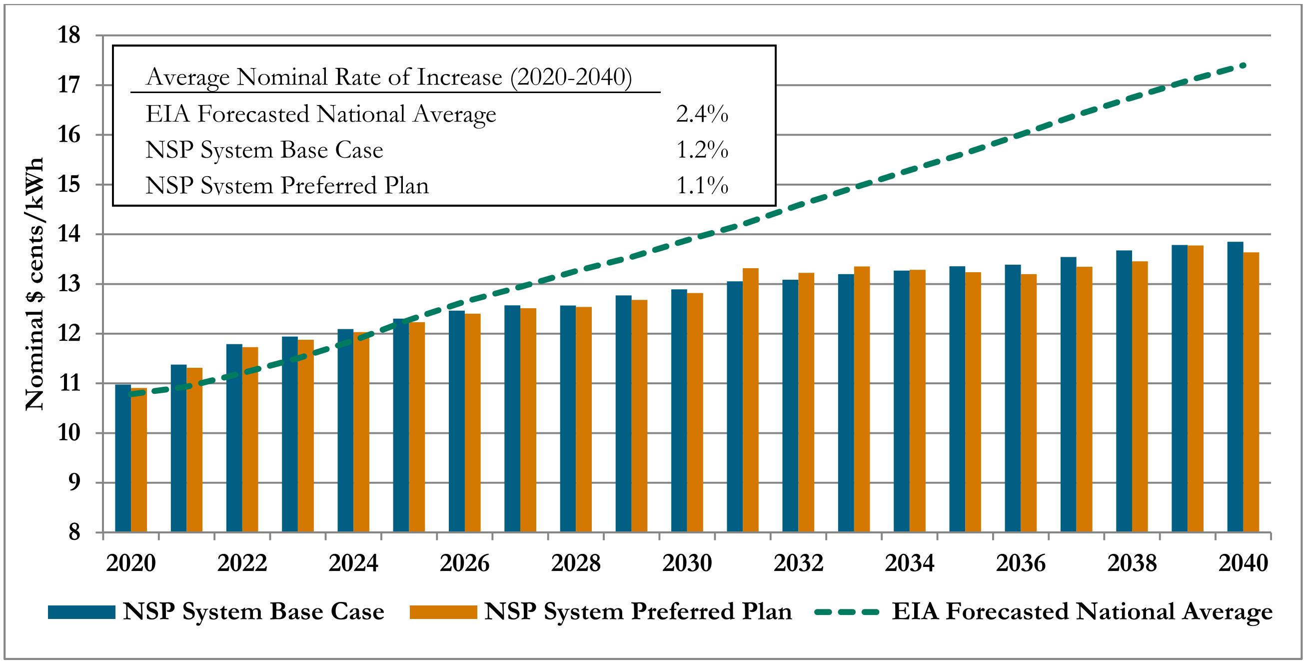
CHAPTER 6
CUSTOMER RATE AND COST IMPACTS

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements less than the Reference Case and just over one (1) percent overall. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly half of the expected national average increase in electricity prices.

Both the Reference Case and the Preferred Plan are designed to meet the Company's goal of reducing carbon emissions 80 percent by 2030, compared to 2005 levels. We did not do the full rate impact calculations discussed in this Chapter on a resource portfolio that does not meet our 80 percent carbon reduction by 2030 goal, we did run a "no 80 by 30" portfolio in our Strategist model and and confirmed that the impacts are in line with our Preferred Plan. In other words, our carbon goals do not materially increase costs for our customers.

To show the cost impact of our proposal over the long-term, we provide a Compound Average Growth Rate (CAGR) comparison of our Preferred Plan compared to the national average nominal cost CAGR for the NSP System in Figure 6-1 and Minnesota in Figure 6-2.

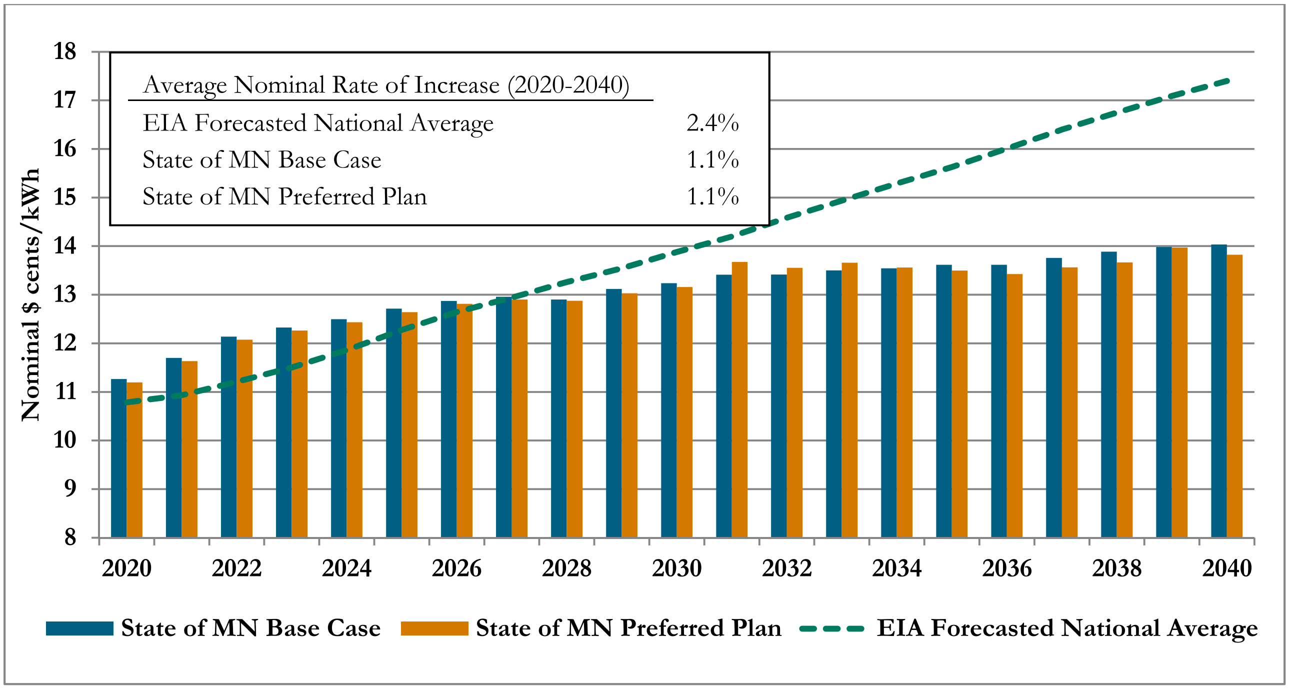
Figure 6-1: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[1] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

[1] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

Figure 6-2: Preferred Plan Average Nominal Cost Comparison (State of Minnesota)



We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model.

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. That said, aside from updated inputs to the class cost allocation factors used in this analysis, the methods are the same as those we used in our last Resource Plan.

In this Section, we explain how we approximated a baseline level of revenue requirements associated with our Reference Case and measured the incremental cost impacts of our Preferred Plan at the NSP system, State of Minnesota, and individual State of Minnesota customer class levels. This is generally consistent with the methodology we used in our last Resource Plan.

I. REFERENCE CASE REVENUE REQUIREMENTS FORECAST METHODOLOGY

To calculate the long-term rate impacts of the Preferred Plan as compared to the

Reference Case, we first developed a forecast of total rates under Reference Case assumptions. This forecast leveraged our detailed five-year financial forecast and a specific approach to identify costs through the end of the planning period (2034) using the CAGR of generation and fuel costs from the Strategist model.[2] Next, we analyzed the annual cost differences by category (i.e. fuel, purchased power, capital expenditures, operating and maintenance costs, taxes, depreciation, etc.) from the Strategist model results for the Reference Case and the Preferred Plan to determine the aggregate system cost impacts and jurisdictional and rate class breakouts.

To determine the overall impact to Minnesota customers and individual customer classes in Minnesota, we converted the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case into a differential revenue requirement forecast. We then jurisdictionalized the differential revenue requirements and applied class allocation principles to calculate impacts on individual Minnesota customer classes. We provide various rate impact analyses and discuss the methodologies below.

II. ESTIMATED RATE IMPACTS AND METHODOLOGY

The primary Strategist model captures only the generation-related portion of the business, or around 50 percent of the total revenue requirements. Developing a total rate forecast beyond 2023 when detailed Company financial models are not available is dependant on making assumptions for capital expenditures and O&M costs for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions are speculative, and the resulting total rate forecast would be similarly speculative.

A. Methodology

To calculate the rate impacts of the Preferred Plan, we started with the 2018 budget forecast of total revenue requirements for the 2019-2023 period.[3] To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

[2] The Strategist model for the Reference Case is the same model used for the Strategist aspect of our Baseload Study, Scenario 1 Reference Case, with the exception that the first Demand Response (DR) bundle was added to the plan, as was also added to the Preferred Plan.
[3] Developed in July 2018 and updated in November 2018.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[4]
- Return on Equity (ROE) of 9.20 percent,[5]
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated historical regulatory adjustments made in rate cases.

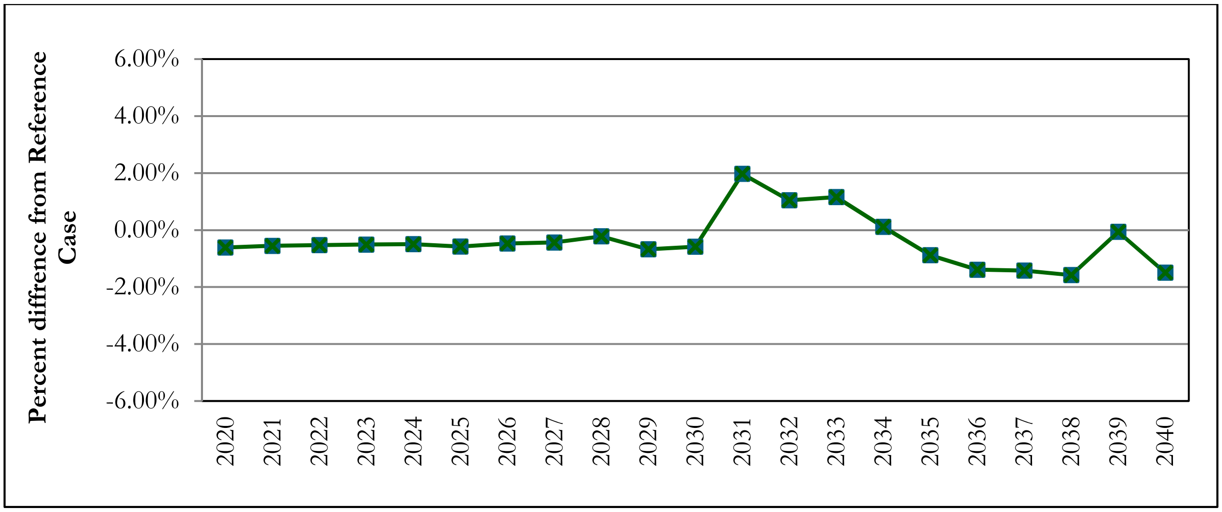
To calculate longer-term rate impacts of the Preferred Plan, we used a combination of the Company's 5-year financial forecast and the Strategist model to project total system revenue requirements for extended periods. For the period beyond 2023, we escalated the capital and O&M costs in the last year of the 5-yr model by the CAGR of the Reference Case as modeled by Strategist.[6] This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the Strategist model to create a "business as usual" long term rate projection. Finally, we calculated the annual difference between the Preferred Plan and the Reference Case to estimate the total rate impact of our Preferred Plan.

B. Estimated Overall Rate Impacts

Figure 6-3 below illustrates the State of Minnesota estimated rate impacts of the Preferred Plan compared to the Reference Case over the long-term.

[4] Data as of November 2018.
[5] The Company acknowledges the recent decision in the TCR docket requiring a 9.06% calculation to be used in future filings and will implement that practice once the order is received.
[6] The Reference Case is Resource Plan Scenario 1; see Appendix F2 for additional details.

Figure 6-3: Annual Percent Change in Revenue Requirements (2020-2040) Preferred Plan above Reference Case – State of Minnesota



The modeling includes accelerated depreciation costs associated with the early retirements of Sherco 3 and King. However, consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant (Docket No. E002/M-17-530), a regulatory asset is another tool that could be used to accompany these early retirements. The use of a regulatory asset for the remaining costs of these plants, including a cost of capital return on those assets, would be an appropriate alternative to accelerating the depreciation because it would keep the Company whole over the remainder of the plants' remaining lives. This would also serve to smooth the projected rate impacts over the planning period.

C. Key Drivers

The major inflection points in the delta of revenue requirements (and rates) is driven entirely by the differences in the set of resources that comprise each the Preferred Plan and Reference Case; these points coincide with key differences in baseload plant retirement dates between the two cases and the timing of replacement resources. The reduction in revenue requirements associated with the early coal unit retirements helps to offset a portion of the ongoing nuclear revenue requirements in the Preferred Plan in the early 2030s, as discussed in more detail below:

- *Extension of Monticello.* In 2028, costs associated with the 10-year license extension begin to ramp up in the Preferred Plan, and capital revenue requirements and O&M costs continue through 2040. In contrast, the Reference Case does not have ongoing capital and O&M costs for Monticello beyond 2030 as it is retired in that case; this results in an approximate $295 million difference between the two cases in fixed costs for Monticello, beginning in 2031.

- *Retirement of Coal Units*. The Reference Case contains ongoing capital and O&M costs for King and Sherco Unit 3, whereas in the Preferred Plan the costs for King terminate in 2029 and Sherco Unit 3 in 2031 due to early retirement. This results in savings of approximately $45 million in fixed costs in 2029, increasing to $110 million in 2031.
- *Load Supporting Resources*. The Preferred Plan has some load-supporting, dispatchable resources added in the early 2030's associated with the Reliability Requirements Proxy discussed in the Baseload Study in this Resource Plan. With the early retirement of King and Sherco Unit 3, the Preferred Plan has a load supporting, dispatchable resource deficiency of approximately 400 MW in that time frame. The Preferred Plan extension of Monticello helps to offset some of this capacity deficiency. The net cost of the load supporting, dispatchable resources in those years ranges from approximately $35 million to $70 million.

The rate increase seen in 2031-2033 reverses in 2034 and the Preferred Plan remains an annual savings producer thereafter. The cost savings from the Preferred Plan are due to the extension of Monticello, which maintains the NSP system 80 percent carbon reduction after Prairie Island retires, without the need to add significant renewables. In the Reference Case, the model adds 2,250 MW of wind in 2034-35 to maintain the 80 percent carbon reduction level, which adds significant costs.

D. These Estimates are not Directly Comparable to Rate Impact Analysis in a Rate Case

We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing for reasons including the following:

- The internal forecast for 2019-2023 is not prepared at the level of detail necessary to support a rate case,
- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,
- We have made no assumptions of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and
- All factors of the Cost of Capital, including debt rates, return on equity, and

debt-equity ratios, are subject to change over the period.

III. ESTIMATED RATE IMPACTS BY CLASS PER YEAR

After determining the incremental revenue requirement impacts from the Preferred Plan and Reference Case for the Minnesota jurisdiction, we determined *class* revenue requirement impacts. We provide the estimated impacts below, then discuss the methodology and calculations that we used. The incremental revenue requirement impact of the Preferred Plan versus the Reference Case is shown in column 3 of Table 6-1 below. Column 4 of the below Table also shows the incremental impact of the Preferred Plan as a percent of the total State of Minnesota revenue requirement.

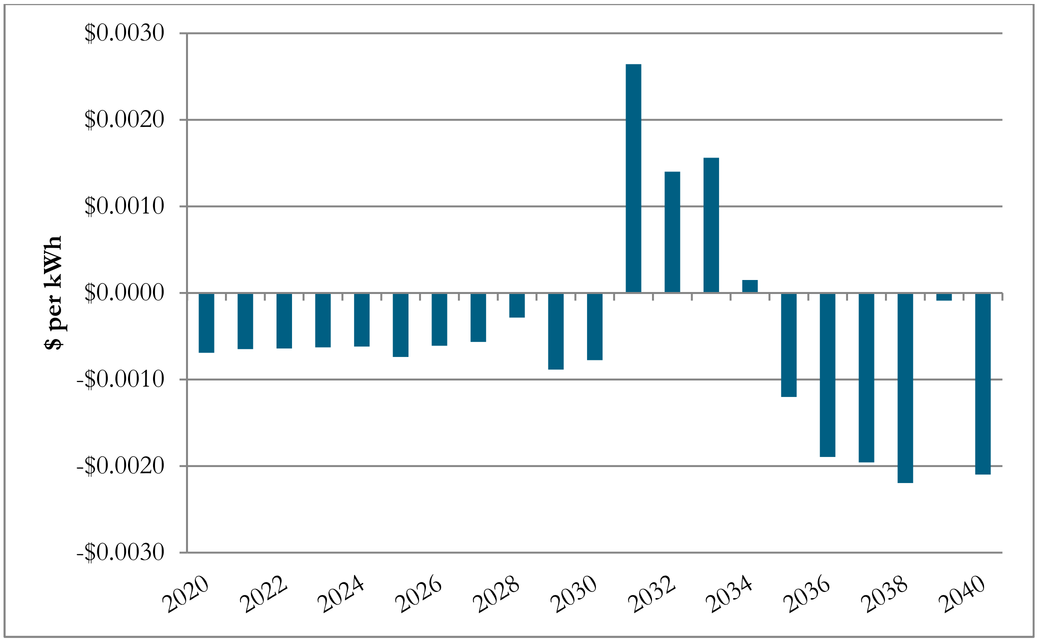
We calculated rate impacts in $ per kWh by dividing each class's revenue requirement in each year by the forecasted sales in each year.

Table 6-1: Estimated Incremental Impact of Preferred Plan
State of Minnesota – All Customers

1	2	3	4
Year	**State of MN Total Revenue Req ($000)**	**Incremental Impact of Preferred Resource Plan** ($000)	**Incremental Impact (%)**
2019	$3,241,019		
2020	$3,309,662	-$20,307	-0.61%
2021	$3,407,431	-$18,905	-0.55%
2022	$3,531,080	-$18,646	-0.53%
2023	$3,567,006	-$18,163	-0.51%
2024	$3,614,422	-$17,880	-0.49%
2025	$3,662,468	-$21,259	-0.58%
2026	$3,711,153	-$17,597	-0.47%
2027	$3,760,484	-$16,389	-0.44%
2028	$3,810,472	-$8,389	-0.22%
2029	$3,861,124	-$26,054	-0.67%
2030	$3,912,450	-$22,932	-0.59%
2031	$3,964,457	$78,174	1.97%
2032	$4,017,157	$41,948	1.04%
2033	$4,070,556	$47,089	1.16%
2034	$4,124,665	$4,568	0.11%
2035	$4,179,494	-$36,862	-0.88%
2036	$4,235,052	-$58,945	-1.39%
2037	$4,291,348	-$61,023	-1.42%
2038	$4,348,392	-$68,746	-1.58%
2039	$4,406,195	-$2,809	-0.06%
2040	$4,464,766	-$66,728	-1.49%

We visually portray this information in Figure 6-4 below.

**Figure 6-4: Incremental Rate Impact of Preferred Plan
State of Minnesota – All Customers**



A. Methodology and Calculations

We determine class revenue requirement impacts by allocating incremental costs to rate classes for each year in the planning period (2020-2034). After costs are allocated, we then calculate revenue requirement impacts for each customer class.

We apply ratemaking treatments to expense items that are impacted by the Resource Plan, as follows:

- Fuel Costs
- Purchased Energy
- Production O&M Expenses
- Property Taxes
- Deferred Income Taxes
- Tax Depreciation and Removal Expense,
- Decommissioning Accruals
- Plant In Service and Associated Depreciation, Construction Work in Progress (CWIP), and Accumulated Deferred Income Taxes

- Bulk Transmission Costs

We discuss our treatment of these expense items for purposes of this rate impact analysis below.

B. Fuel Costs and Purchased Energy

Fuel and purchased energy costs are allocated to classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[7]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.27%	3.04%	67.24%	0.44%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

C. Production Expense, Property Taxes, Deferred Income Taxes, Tax Depreciation and Removal Expense and Decommissioning Accrual

These expense items are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[8] We provide the approved plant stratification analysis that we applied to production O&M expenses for each plant type below:

[7] See Docket No. E002/GR-15-826, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, (June 12, 2017).
[8] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$825	$825 / $825	100.0%	0.0%
Fossil	$2,089	$825 / $2,089	39.5%	60.5%
Nuclear	$4,286	$825 / $4,286	19.3%	80.7%
Combined Cycle	$1,079	$825 / $1,079	76.5%	23.5%
Wind	$15,847	$825 / $15,847	5.2%	94.8%
Solar	$8,182	$825 / $8,182	10.1%	89.9%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, nuclear, etc.) to the replacement cost of a CT. CT are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After production O&M costs originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator approved by the Commission in our most recent rate case.[9] The D10S allocator is simply each class's load that is coincident with the NSP system peak load. We provide the approved D10S class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	36.14%	3.28%	60.59%	0.00%

[9] *Id.*

D. Generation Rate Base Costs Including Plant in Service, Depreciation, CWIP and Accumulated Deferred Income Taxes

Rate base related costs from each type of generation plant are also split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[10] As was true with the expense items listed in *part 2* above, rate base costs classified as being energy-related are allocated to class using the E8760 energy allocator. Likewise, the capital costs that have been classified as being capacity or demand-related are allocated to customer class using the D10S capacity allocator.

E. Bulk Transmission Costs

As ordered by the Minnesota Commission, all rate base and expense items related to bulk transmission are classified as being capacity or demand-related and are allocated to customer class using the Commission-approved D10S capacity allocator.[11]

IV. DETERMINING CLASS RATE IMPACTS

In order to show the estimated impacts of the Preferred Plan on customer rates and bills, we provide a breakdown by customer class for the 2020-2040 period, and in more detail for the immediate five-year 2019-2023 period at the Minnesota customer class levels.

Figure 6-5 below shows the estimated incremental impacts of our Preferred Plan over the long-term by customer class.

[10] *Id.*
[11] *Id.*

Figure 6-5: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota

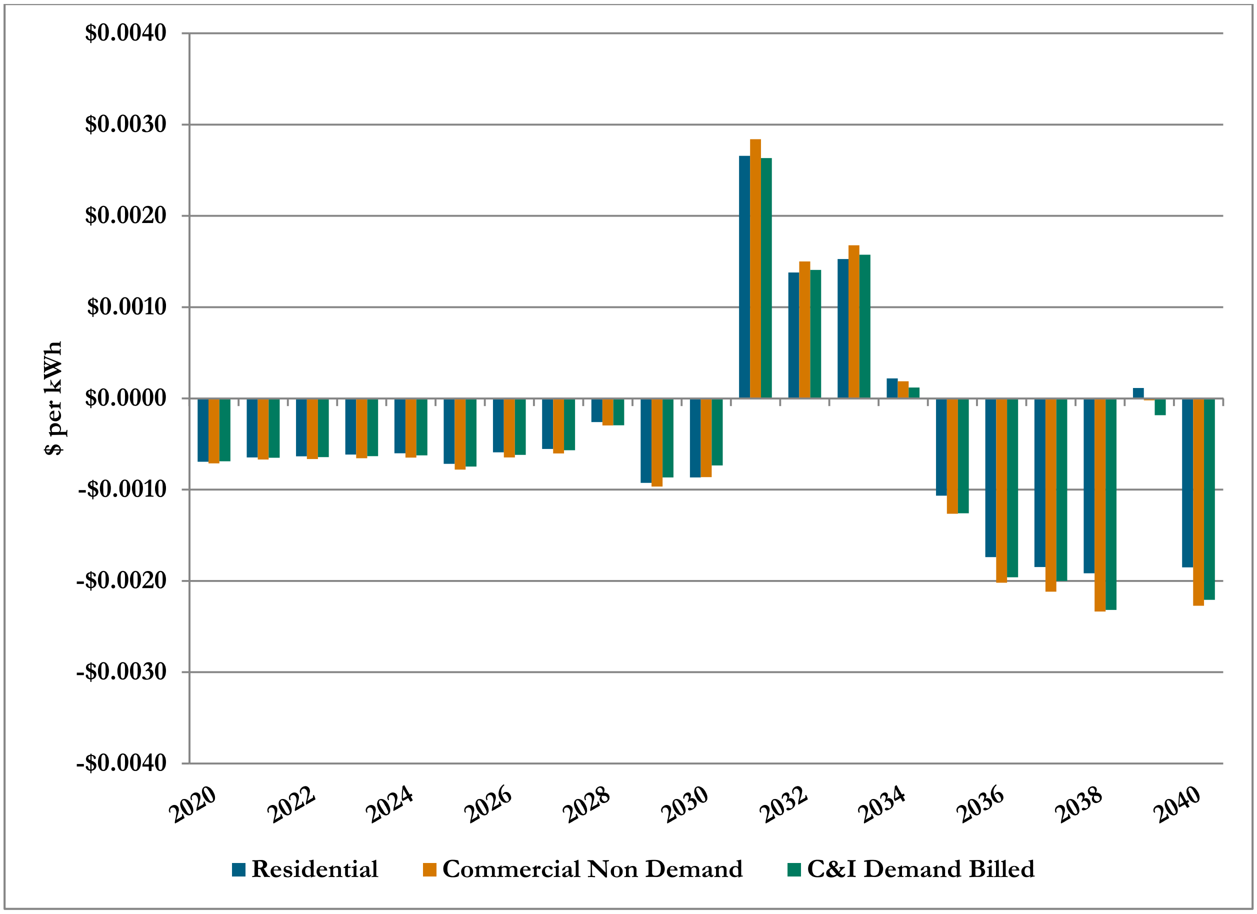


Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2019	2020	2021	2022	2023	2024	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	14.488¢	14.367¢	14.506¢	14.847¢	15.377¢	15.526¢	N/A
Cumul Increase (¢/kWh)		-0.121	0.018	0.359	0.889	1.037	N/A
Cumulative Increase (%)		-0.84%	0.12%	2.48%	6.14%	7.16%	1.39%
$ Impact/Month, @ 650	($0.79)	$0.11	$2.33	$5.78	$6.74	N/A	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	13.218¢	13.218¢	13.167¢	13.511¢	13.946¢	14.599¢	14.855¢
Cumul Increase (¢/kWh)		-0.052	0.293	0.727	1.380	1.636	N/A
Cumulative Increase (%)		-0.39%	2.22%	5.50%	10.44%	12.38%	2.36%
$ Impact/Month, @ 1,000	($0.52)	$2.93	$7.27	$13.80	$16.36	N/A	N/A
Demand (avg rate, ¢/kWh)	9.370¢	9.300¢	9.707¢	10.040¢	10.471¢	10.570¢	N/A
Cumul Increase (¢/kWh)		-0.070	0.336	0.669	1.100	1.199	N/A
Cumulative Increase (%)		-0.75%	3.59%	7.14%	11.74%	12.80%	2.44%
$ Impact/Month, @ 37,500	($26.30)	$126.15	$250.98	$412.56	$449.71	N/A	N/A
Street Ltg (avg rate, ¢/kWh)	25.290¢	25.027¢	24.668¢	24.917¢	25.624¢	26.079¢	N/A
Cumul Increase (¢/kWh)		-0.262	-0.622	-0.372	0.334	0.790	N/A
Cumulative Increase (%)		-1.04%	-2.46%	-1.47%	1.32%	3.12%	0.62%
$ Impact/Month, @ 60	($0.16)	($0.37)	($0.22)	$0.20	$0.47	N/A	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2024) for the Preferred Plan would be expected to increase the average Residential rate by about 1.39 percent on a compounded annual basis through 2024. That is equivalent to a total increase of $6.74 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 2.44 percent on a compounded annual basis through 2023, which is equivalent to an increase of 1.199 cents per kWh above the 2019 level.

V. FACTORS IMPACTING NEAR-AND LONG-TERM RATE ESTIMATES

We note that the following factors could have an impact on the estimated rate impacts in the planning period:

Depreciation Expense for Coal Closures. The modeling and estimated rate impacts reflect accelerated depreciation associated with the early retirement of the Allen S. King and Sherco Unit 3 plants. This is consistent with the Company's current method of recovery for Sherco 1 and 2. As noted previously, however, and consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant, a regulatory asset is another tool that could be used to accompany these early retirements. An alternative regulatory treatment such as this would impact this analysis.

Generation Ownership: Owned and Purchased Power Agreement resources will have different cost patterns, which will impact this analysis to the extent a resource addition differs in terms of ownership from what was modeled.

Taxes. This analysis is based on present tax conditions. Any tax changes will impact the modeling underlying this analysis and thus the rate impact results.

Nuclear Decommissioning Trust. There are several items regarding the NDT that may have a material impact on costs included in this resource plan.

Pending or Future Regulatory Decisions. Rate case and resource acquisition outcomes have the potential to impact rates and system needs.

Large Customer Changes. The loss or addition of a large business customer has the potential to impact both rates and system needs.

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota;

xx by courier; or

xx by electronic filing.

Docket Nos. E002/RP-19-368
E002/RP-15-21
E002/GR-15-826
Xcel Energy Miscellaneous Electric

Dated this 1st day of July 2019

/s/

____

Jim Erickson
Regulatory Administrator

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APPENDIX A - COMPLIANCE MATRIX

Xcel Energy is committed to complying fully with all applicable statutes and rules and we believe our Plan reflects appropriate implementation of all requirements. We have prepared a matrix reflecting our inventory of requirements to be met in this Application and cross-referenced to the portion of the Plan that fulfills each compliance item.

Rules, Statutes, and Orders

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
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. After the initial report, 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.	Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report Appendix N6: Renewable Energy Standard: Rate Impact Report
Minn. Stat. §216B.1691 Renewable Energy Objectives	Subdivision 3.	Utility plans filed with commission. (a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422, demonstrating to the commission the utility's effort to comply with this section. In its resource plan, each electric utility shall provide a description of: (1) the status of the utility's renewable energy mix relative to the objective and standards; (2) efforts taken to meet the objective and standards; (3) any obstacles encountered or anticipated in meeting the objective or standards; and (4) potential solutions to the obstacles.	Chapter 3: Minimum System Needs Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report
Minn. Stat. §216B.1691 Renewable Energy Objectives	Subdivision 10.	"Utility acquisition of resources. 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 on or before March 1, 2008, a renewable energy plan setting forth the manner in which the utility proposes to meet the requirements of this section. The utility shall update the plan as necessary in its filing under section 216B.2422. The commission shall approve the plan unless it determines, after public hearing and comment, that the plan is not in the public interest. As part of its determination of public interest, the commission shall consider the plan's impact on balancing the state's interest in: (1) promoting the policy of economic development in rural areas through the development of renewable energy projects, as expressed in subdivision 9; (2) maintaining the reliability of the state's electric power grid; and (3) minimizing cost impacts on ratepayers."	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 N1: Annual Report: Minnesota Electric
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 4: Preferred Plan Appendix H: Environmental Regulations Review

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
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 F2: Strategist Modeling Assumptions & Inputs
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 F2: Strategist Modeling Assumptions & Inputs
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 F7: Minnesota Energy Storage Systems Assessment
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 N9: Triennial Filing: Nuclear Decommissioning Appendix N10: Nuclear Worker Transition Plan
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 N1: Annual Report: Minnesota Electric
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 F3: Scenario Sensitivity Analysis: PVRR and PVSC Summary
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.*	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
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 F6: Resource Option Appendix G1: Demand Side Management Appendix I: Supporting Infrastructure: Transmission & Distribution
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 Appendix F2: Strategist Modeling Assumptions & Inputs
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 D: 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.	Appendix F2: Strategist Modeling Assumptions & Inputs Attachment A
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 F2: Strategist Modeling Assumptions & Inputs Attachment A
Docket No. E-002/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 H: Environmental Regulations Review Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: REO-RES Compliance Report Appendix N7: Annual Report: Solar Energy Standard
Docket No. E-002/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 as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.	Chapter 4: Preferred Plan Appendix H: Environmental Regulations Review Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: REO-RES Compliance Report Appendix N7: Annual Report: Solar Energy Standard
Docket No. E-002/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 2	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 regarding its completeness review of MP's resource plan in Docket E015/RP-13-53.	See below:

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	1. How the addition of SO2 allowance prices would have impacted its base case and preferred plan; and	Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	2. How the use of unforced capacity would have impacted its base case and preferred plan;	Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	3. How the use of Commission-approved CO2 values from its November 2, 2012 Order affect its base case and preferred plan;	Superceded by the June 11, 2018 Order in Docket Nos. E-999/CI-07-1199 & E-999/DI-17-53 Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	4. How MP has considered water consumption issues and potential effects on aquatic life from water intake and discharge in its resource plan, both qualitatively and quantitatively.	Appendix H: Environmental Regulations Review Appendix F2: Strategist Modeling Assumptions & Inputs Attachment B
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	5. How MP has taken into account possible effects of drought and high water temperature on generating plant availability in its modeling, including the results of modeling the range of these possible effects. Reference to 13-53 Order pg 4.	Appendix F2: Strategist Modeling Assumptions & Inputs Attachment B
Docket No. E-002/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**	E015/RP-13-53; 5/10/13 Order Page 4	6. How MP has considered demand side management (DSM) programs in its resource plan, and the pros and cons of DSM being considered a reduction in load versus a resource to be chosen, including modeling a range of assumptions.	Chapter 3: Minimum System Needs Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs Appendix G1: Demand Side Management
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 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 O1: Summary of IRP Stakeholder Engagement
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 4a	4. Xcel's resource plan is modified as follows: a. to remove 400 MW of large-scale solar in 2016–2021. Xcel shall acquire approximately 650 MW of solar in 2016–2021 through a combination of the Company's community solar gardens program or other acquisitions. The Company may pursue additional, cost-effective solar resources if it is in the best interests of its customers.	Chapter 3: Minimum System Needs Appendix N8: Monthly Report: Solar Gardens June 2019
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 7	7. Xcel's schedule to retire Sherco 2 in 2023, and Sherco 1 in 2026, is approved.	Chapter 4: Preferred Plan
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 8	8. The Commission finds that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.	Chapter 4: Preferred Plan
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.	Chapter 3: Minimum System Needs Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix G1: Demand Side Management

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
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 G1: Demand Side Management
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 13	13. Xcel shall file its next resource plan on February 1, 2019.	See Docket No. E002/RP-15-21, Minnesota Public Utilities Commission's Order Extending Deadline for Filing Next Resource Plan (January30, 2019)
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 14a	14. In its next resource plan filing, Xcel shall: a. describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.	Appendix J1: Baseload Study
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 14b	b. evaluate combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could in the aggregate meet post-retirement energy and capacity needs as well as contribute to grid support.	Chapter 5: Economic Modeling Framework Appendix L: Sherco CC Appendix I: Supporting Infrastructure: Transmission & Distribution Appendix J1: Baseload Study
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 14c	c. explore the role of cost-effective combined heat and power solutions.	Appendix S: Combined Heat and Power Study (EPRI) Appendix F6: Resource Options
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 14d	d. report on its solar acquisition progress.	Chapter 3: Minimum System Needs Appendix N8: Monthly Report: Solar Gardens June 2019
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 14e	e. provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025.	Appendix G1: Demand Side Management Appendix G3: DR Cost Effectiveness at NSP (Brattle)
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 14f	f. summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.	Appendix G1: Demand Side Management
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 F1: Load & DER Forecasting
Docket No. E999/CI-07-1199 & 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	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 F2: Strategist Modeling Assumptions & Inputs

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E999/CI-07-1199 & 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 2B	B. Incorporate, for all years, the high end of the range of environmental costs for CO2 as approved by the Commission in its January 3, 2018 order.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & 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 2C	C. Incorporate the low end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations, in lieu of environmental costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & 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 2D	D. Incorporate the high end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for CO2 regulations, in lieu of environmental costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & 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 2	Consistent with the Commission decision in the Order Updating Environmental Costs, utilities shall include at least one scenario that excludes consideration of CO2 costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist 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 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 F2: Strategist 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 F3: Scenario Sensitivity Analysis: PVRR and PVSC 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 30, 2019 Order**	Order Point 1	1. Xcel's next resource plan shall be filed by July 1, 2019.	This filing has been made July 1, 2019 in Docket No. E002/RP-19-368

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
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 30, 2019 Order**	Order Point 2	2. Xcel shall submit the files necessary to recreate the Company's 2020–2034 Reference Case, as summarized at Xcel's October 23, 2018 IRP Workshop, and shall provide the Strategist files with the same assumptions as in the Company's 2020–2034 Reference Case but using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon.	DOC IR No. 1 Docket No. IP6949, E002/PA-18-702 - submitted on November 27, 2019. See Compliance Filing submitted on May 30, 2019 in Docket No. E002/RP-19-368 regarding this Order Requirement for additional information.

APPENDIX B – ACRONYMS & TERMS

ACRONYM / TERM	DEFINITION
AC	Alternating Current
ACE	Affordable Clean Energy rule
ACI	Activated Carbon Injection
ADMS	Advanced Distribution Management System
AEO	Annual Energy Outlook
AFC	Accelerated Fleet Change
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ASHP	Air-Source Heat Pumps
AWEA	American Wind Energy Association
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BO	Buildout Scenario
BSER	Best System of Emission Reduction
C&I	Commercial and Industrial (Customers)
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
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.
C-BED	Community-Based Energy Development
CBECS	Commercial Buildings Energy Consumption Survey
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost of Service Stufy
CCRs	Coal Combustion Residuals (often referred to as coal ash)
CCS	Carbon Capture and Sequestration
CEE	Center for Energy and Environment
CEL	Capacity Export Limit
CER	Capital Project Module
CERA	Cambridge Energy Research Associates

ACRONYM / TERM	DEFINITION
CFC	Continued Fleet Change
CH_4	Methane
CHP	Combined Heat and Power
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.
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
CPNode	Commercial Pricing Mode
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
DEM	Drive Electric Minnesota
DER	Distributed Energy Resources
DG	Distributed Generation
DIR	Dispatch Intermittent Resource Protocol
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
E3	Energy and Environmental Economics, Inc.
ECC	Economic Carrying Charge
EE	Energy Efficiency
eGRID	Emissions and Generation Resource Integrated Database
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELGs	Effluent Limitation Guidelines
EPA	Environmental Protection Agency

ACRONYM / TERM	DEFINITION
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.
EPRI	Electric Power Research Institute
EQB	Environmental Quality Board
ESA	Endangered Species Act
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.
FIPs	Federal Implementation Plans
FL&U	Fuel Lost and Unaccounted
FLISR	Fault Location, Isolation, and Service Restoration
FWS	U.S. Fish and Wildlife Service
Gas Burn	Energy from New Natural Gas Generation
GAF	Generation Module
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
HDVs	Heavy-Duty Vehicles
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
INPO	Institute of Nuclear Power Operations
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ISOs	Independent System Operators
JCOSS	Jurisdictional Cost of Service Study
kV	Kilovolt

ACRONYM / TERM	DEFINITION
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
LCM	Life Cycle Management
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
LCR	Local Clearing Requirement
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
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRR	Local Reliability Requirement
LRZ	Local Resource 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.
MDVs	Medium-Duty Vehicles
MEC	Mankato Energy Center
MEFF	Minnesota Energy Future Framework
MGP	Manufactured Gas Plants
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.
MMBTU	Million British Thermal Units
MMERA	Minnesota Mercury Emissions Reduction Act
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
M-RETS	Midwest Renewable Energy Tracking System
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
MVA	Mega Volt Amps: 1,000,000 amps or 1,000 kVA

ACRONYM / TERM	DEFINITION
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
NDPSC	North Dakota Public Service Commission
NEEP	Northeast Energy Efficiency Partnerships
NERC	North American Electric Reliability Corporation
NGEA	Minnesota's Next Generation Energy Act
NMFS	National Marine Fisheries Service
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
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
O&M	Operating and Maintenance
O_3	Ozone
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
PI	Prairie Island
PIRA	Petroleum Industry Research Associates
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
PPA	Power Purchase Agreement
PPB	Parts Per Billion
PPM	Parts Per Million

ACRONYM / TERM	DEFINITION
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
RA	Resource Adequacy
RAC	Reliability Assessment Commitment
RAVI	Reasonably Attributable Visibility Impairment
RCRA	Resource Conservation and Recovery Act
RDF	Refuse Derived Fuel or 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
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.
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
RHR	Regional Haze Rule
RIIA	Renewable Integration Impact Assessment
RPS	Renewable Portfolio Standard
RSG	Revenue Sufficiency Guarantee (Charges): Direct result of production shortfalls relative to earlier forecasts.
RTF	Resource Treatment Framework
RTO	Regional Transmission Organization
S*R	Solar Rewards (Company's Program)

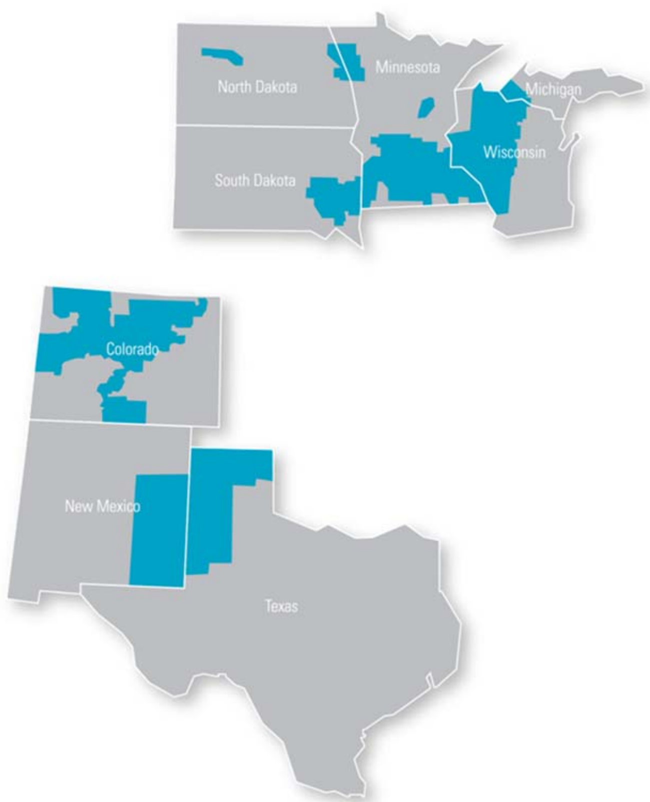
ACRONYM / TERM	DEFINITION
S*RC	Solar Rewards Community (Company's Community Solar Gardens Program)
SAIDI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SAIFI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SCADA	Supervisory Control and Data Acquisition
SCC	Social Cost of Carbon
SCR	Selective Catalytic Reduction
SDPUC	South Dakota Public Utilities Commission
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
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxide
SolarTAC	Solar Technology Acceleration Center
SPP	Southwest Power Pool
SQ	Status Quo
S-RECs	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.
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.
THI	Temperature Humidity Index
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

ACRONYM / TERM	DEFINITION
TSD	Technical Support Document
UCAP	Production Capability Value
USACE	U.S. Army Corps of Engineers
V2G	Vehicle-To-Grid
VAr	Voltage and Reactive Power
VMT	Vehicle Miles Traveled
VOCs	Volatile Organic Compounds
W2B	Wind2Battery Project
WDNR	Wisconsin Department of Natural Resources
WOTUS	Waters of the United States
WTP	Worker Transition Plan
ZRC	Zonal Resource Credit

APPENDIX C – ABOUT XCEL ENERGY

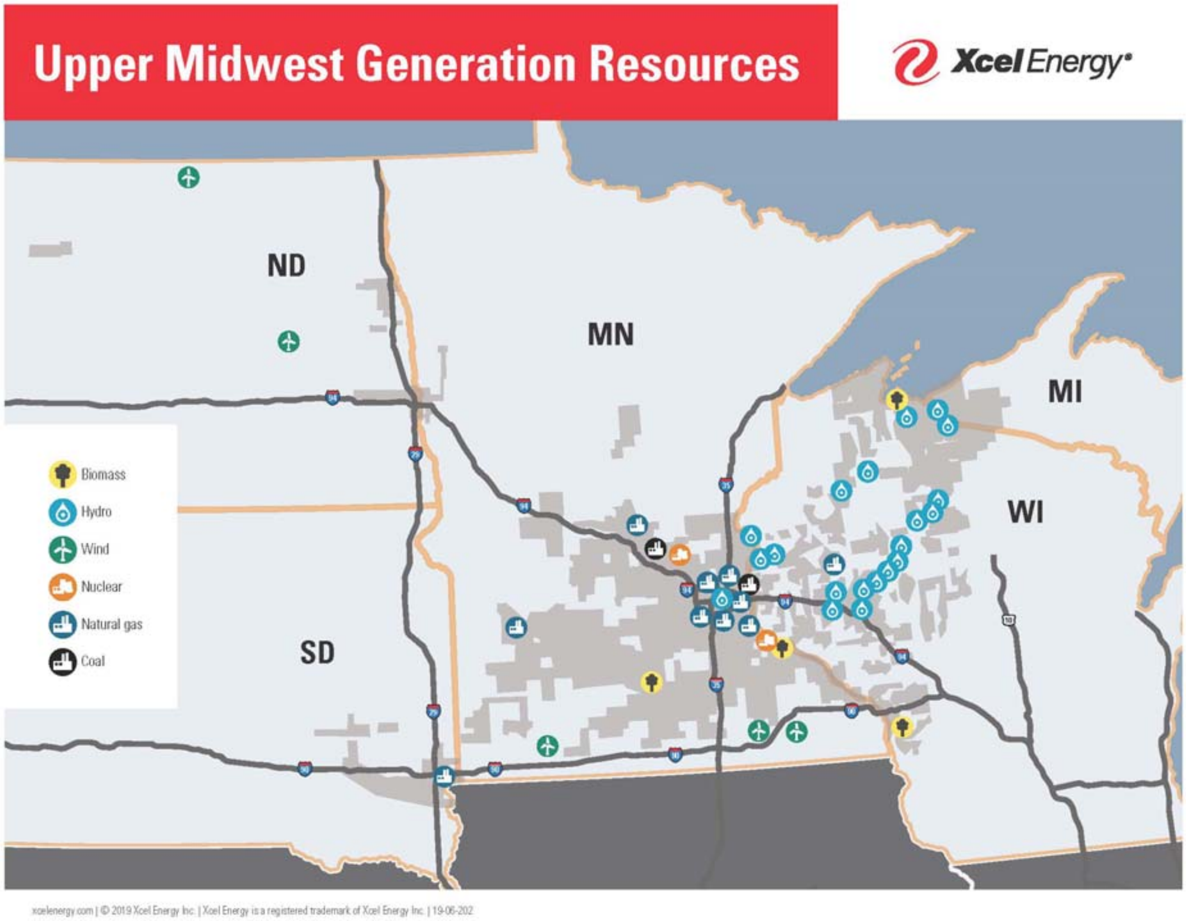
Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated operations in eight Midwestern and Western states - Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of energy-related products and services to approximately 3.6 million electricity customers and 2 million natural gas customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies – Northern States Power Company-Minnesota (NSPM), which serves North Dakota and South Dakota in addition to Minnesota; and Northern States Power Company-Wisconsin (NSPW), which serves Wisconsin and Michigan – collectively referred to as the NSP system. Xcel Energy serves over 1.8 million customers in its NSP service territories. Figure 1 below illustrates Xcel Energy's nationwide territory.

Figure 1: Xcel Energy Territory



Approximately 88 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 12 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers make up approximately 29 percent of electricity sales, with commercial and industrial customers making up most of the remaining 71 percent.

Figure 2: NSP System Generation Resources



NSP operates a diverse electric generating fleet, which includes facilities that use several different types of fuel: coal, natural gas, nuclear, wind, hydro, and biomass. This fleet of generating resources is illustrated by the map in Figure 2 above. The diversity of this fleet provides customers with a variety of generation options and protects them from the excessive risk of reliance on any one type of resource. Our overall strategy for purchasing our diverse generating fuels focuses on three objectives: competitive cost, diversity and reliability. Our fleet includes power plants with a net maximum capacity of over 9,500 MW, more than 8,400 miles of transmission lines, and approximately 550 transmission and distribution substations. We also have over 3,700 MW of Purchase Power Agreements (PPAs) for renewable and natural gas resources, including over 200 MW of large-scale solar and an additional expected 600 MW of Community Solar Gardens online by 2020.

Xcel Energy has long been a leader in delivering clean energy while maintaining outstanding reliability and affordability. Back in 2005, we were the leading utility wind energy provider in the country, despite the fact that wind comprised only 3 percent of our generation. By 2027, we expect renewable energy — the vast majority being wind — will account for 48 percent of our mix and will be our largest source of energy for our customers.

Along the way, we have made steady progress reducing carbon dioxide by transitioning away from fossil fuels, incorporating renewables and developing award-winning energy efficiency programs. Our 2018 carbon emissions were approximately 40 percent lower than our 2005 baseline. That progress put us on pace to hit our previous goal of reducing carbon 60 percent across all eight states in which we do business by 2030.

But a confluence of market forces — improving technology, falling prices and the risk of climate change — convinced us that we can do more, sooner. That is why in December, we became the first electric utility in the country to announce our aspiration to produce 100-percent carbon-free electricity for customers by 2050. At the same time, we announced a new interim target of reducing carbon dioxide emissions 80 percent by 2030.

Setting our sights on this ambitious vision allows us to drive the conversation rather than react to it. It also gives us time for the development of technologies not currently available that will be critical for achieving 100 percent carbon-free electricity. We are excited to make advances towards this vision and build the future together.

APPENDIX D – NON-TECHNICAL SUMMARY

I. INTRODUCTION

Northern States Power Company-Minnesota is a wholly-owned operating subsidiary of Xcel Energy, Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company-Wisconsin, the integrated NSP System of generation and transmission assets that serves more than 1.8 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This 2020-2034 Upper Midwest Integrated Resource Plan builds on our strong foundation of cost-effective environmental performance and the generating fleet transition we began in our last Resource Plan.

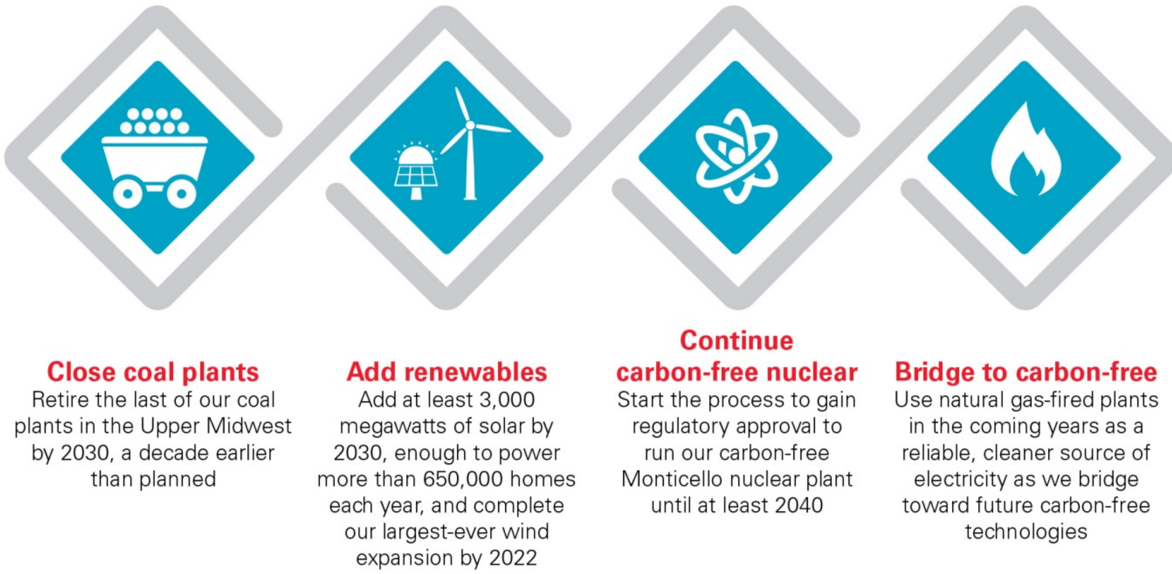
Our Resource Plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We engaged a national expert on energy policy and economics, Dr. Susan Tierney with Analysis Group. Dr. Tierney not only brought a national perspective, but was also an independent third party that helped facilitate engaging and productive dialogue with stakeholders. We also retained Energy and Environmental Economics, Inc. (E3), to perform independent modeling and analysis of our system in order to ensure transparent work and access to the data and models for stakeholders. E3 is a recognized industry-leading firm based in San Francisco and consults extensively with utilities, developers, government agencies, and environmental groups on clean energy issues.

To develop our plan, we analyzed numerous assumptions and sensitivities to identify the plan that best meets customer needs, achieves our obligations and goals, and ensures we maintain a resilient and reliable grid. Our Preferred Plan represents the set of generation and conservation resources that we propose to meet our customers' needs over the next 15 years, which we believe is the best suite of resources that meets our planning objectives.

Figure 1: Xcel Energy Integrated Resource Plan Objectives

Our Preferred Plan includes the elimination of coal-fired generation from our system by 2030, the acquisition of at least 3,000 megawatts (MW) of utility-scale solar, a substantial increase in energy efficiency (EE) programs and Demand Response (DR), an operating extension of our carbon-free Monticello nuclear plant, and a proposal to construct a new combined cycle at our Sherco site. In total, we have an ambitious plan that supports the Company's goal of reducing carbon emissions 80 percent by 2030, and it moves us toward our ultimate vision of 100 percent carbon-free energy by 2050.

Figure 2: Preferred Plan Highlights



Our Preferred Plan will be evaluated based on its ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.[1]

II. A CHANGING PLANNING LANDSCAPE

There are key internal and external market contexts that affect how we have developed, and plan to execute on, our Preferred Plan. Below provide a contextual discussion of the planning landscape within which we developed and are presenting the results of our current resource planning efforts.

A. Regional Reliability and Market Constructs

While the regional system operator that designs many of our market and planning requirements continues to examine the effects of high renewable adoption on the grid, it has not yet developed robust and forward-looking capacity accreditation constructs to account for how renewables' contributions to peak demand will change

[1] Minn. R. 7843.0500, subp. 3

over time. This introduces complexity to designing a plan far into the future, and how we carry out those plans.

Likewise, while we are committed to substantially increasing renewables on our system to achieve our carbon reduction goals, we also anticipate facing challenges to integrating this new clean generation, given the delayed interconnection studies and current limited state of open transmission availability. Our ability to connect these new renewables in a cost-effective manner depends materially on constructs that enable careful management of our interconnection rights in the near-to-medium term as well as new transmission in the long term.

B. Distributed Energy Resources (DER)

At the same time as we work to clean our grid mix, we also recognize that customers are now exercising more choice around how and from where they consume energy. Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. The opportunities are exciting; however, customer adoption of DER and new types of load behind the meter introduces uncertainties in our planning processes – particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

Fortunately, we have made progress integrating distribution planning into our resource planning. As with other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning, and evaluating and procuring the next generation of distribution planning tools. These tools are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes. Thus, while work continues to incorporate these planning processes and DER on our system, additional work and tools are needed.

C. Community and Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. This is particularly true of our coal facilities, where the plants are prominent places of employment and contributors to the property tax base in the community.

As we continue toward achievement of our aggressive carbon goals, we will continue to make significant clean energy investments in the states we serve. As we do so, we will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

D. Customer Preferences

We are increasingly hearing from our customers that they have a growing interest in increasing their energy management capabilities and desire a more customized energy mix than has been traditionally available. Residential customers tell us that they value choice and clean, affordable, and reliable energy. At the same time, municipalities within our service territory are expressing changing expectations to address their citizens' interests in achieving sustainability goals and engage residents around energy issues.

Our customers also are interested in various types of self-generation. This includes increased small-scale solar penetration through behind the meter installations or community solar gardens. Industrial customers are also interested in exploring the addition of larger scale Combined Heat and Power (CHP) installations at their facilities. The installation of self-generation on our system impacts our resource needs, planning goals, and ultimate resource mix.

We also know that customers are sensitive to rate changes. For example, our large industrial customers are energy-intensive and thus highly-sensitive to energy rates, with less sensitivity to other terms of service. These are key considerations as we plan our resource mix to meet the needs of our customers over the planning period.

E. Supply and Technology Trends

The rapid pace of advancement in energy technologies has impacted and will continue to impact the future of our industry. Emerging technologies related to grid modernization, energy storage, electric vehicles, resource extraction, renewable energy and other alternative fuels and generation methods are enabling a smarter and more resilient energy system.

While this new technology provides opportunities for a modernized energy system, operating that system is a complex matter. We are taking a measured approach to identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the safety of our operations and overall value to customers. Our approach to these emerging technologies is to learn from the current deployments, both internal to Xcel Energy and within the industry, and implement initiatives at the pace of value to our customers and operations.

F. Five State Integrated System

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest system – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. Indeed, planning for the varied needs of each of these five states was critical to the formation of our Preferred Plan.

G. The Evolving NSP System

This accelerated transition away from coal requires the Company to plan for the retirement of 2,400 MW of coal-fired generation in the next decade, which represents almost one-fourth of the total capacity in our current generation fleet. We will also experience a reduction in energy resources due several purchase power contracts expiring.

At the same time, we are increasing the amount of renewable generation on our system. Yet, these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability. As such, our plan incorporates a Reliability Requirement as a bridge until the current planning processes adapt to recognize the transition that is underway.

Taken together, the impact of these system changes was critical to our resource planning analysis as we evaluated meeting our capacity and energy needs while maintaining reliability, retaining flexibility, and avoiding over-reliance on any one fuel source.

The planning landscape underlying this Resource Plan has greatly informed our planning efforts. We continue to believe that proactive leadership in the face of evolving industry, new and proposed environmental regulation, customer expectations, emerging technologies, and changes to the NSP System will allow us to affirmatively address these trends rather than being shaped by them. These evolving factors also call for sufficient flexibility that allows us to adjust and react as we gain more clarity on the planning landscape.

III. KEY CONSIDERATIONS OF THE PREFERRED PLAN

Resource Planning is a complex and integrated process of planning for the capacity, energy, and emission requirements of the electric system. The process incorporates a number of key assumptions or industry projections that helps all participants develop a common vision of what the future planning environment may look like. This ongoing planning process requires utilities to examine and establish a long-term proposal for management, operation, and expansion or contraction of their generating and demand management resources to meet customer needs.

Traditionally a primary focus of resource planning has been to identify the least-cost approach to provide reliable service and meet growing demand. While this is still a part of our foundation, this Plan begins to move away from a more concentrated view of traditional thermal generation to incorporating new generation technologies, increasing carbon-free energy, reducing emission profiles, and thereby positioning the NSP System for the future.

The Preferred Plan we present was developed to address the planning landscape in which it was developed and in consideration of our four key planning objectives: (1) Environmental Benefits and Innovation (2) Reliability (3) Cost (4) Risk Mitigation and Flexibility. Underscoring all of these objectives is our commitment to our employees and the communities within which we operate.

A. Environmental and Innovation

Environmental benefits and the technological innovations that will help us achieve them are front and center in this Resource Plan process. We have made a bold commitment to achieve 80 percent carbon reduction from 2005 levels by 2030, and have considered this target a modeling pillar for all of our potential scenarios. Our Preferred Plan achieves this goal in several ways. First, our Preferred Plan eliminates coal from our system by 2030, extends our carbon-free Monticello plant to 2040, adds at least 4,000 MW of new renewable resources, including substantial new solar capacity additions, and maintains the wind levels committed to in our previous Resource Plan by replacing renewables with renewables when they reach the end of their operating lives.

Many of these resource additions are not needed for a number of years. We therefore expect technological advancements and innovations will create opportunities in future planning and procurement processes if we are able to retain the flexibility we seek with this plan.

B. Reliability

Our responsibility to ensure a reliable electricity supply for our customers is a fundamental underpinning of our Preferred Plan. We therefore developed a Reliability Requirement that establishes a minimum level of firm dispatchable resources that is required to serve our customers' needs in every hour of every day. We developed the Reliability Requirement through analysis of industry trends and careful study of our system's performance and the broader Midcontinent Independent System Operator (MISO) system's performance during both winter and summer days when renewables were unavailable – sometimes for lengthy durations.[2]

This Requirement does not drive any firm dispatchable load supporting resource additions in our Preferred Plan until after 2030. Prior to 2030, our Preferred Plan relies on two primary sources to ensure reliability: (1) combined cycle (CC) generating plants – specifically the Mankato Energy Center (MEC) that we have proposed to acquire, one at our Sherco location near Becker, Minnesota (Sherco CC), and (2) our Monticello and Prairie Island nuclear units. Combined cycle generating units are intermediate natural gas resources that efficiently address reliability challenges associated with the variability of wind and solar and customer needs, because they can vary their output to adapt as demand for electricity changes over the course of the day and year. With respect to nuclear generation, our proposed extension of the Monticello operating license not only represents a carbon-free workhorse of a resource, it also enhances fuel diversity and provides a generation resource that is not subject to seasonal fuel supply limitations.

C. Cost

Along with leading the clean energy transition and enhancing the customer experience, keeping customer costs low is one of Xcel Energy's central, guiding objectives. Since our last Resource Plan, renewable technology costs – and in particular, solar costs – have continued to decline; we expect this trend to continue

[2] MISO is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. The NSP System is part of MISO, which is part of the Eastern Interconnection that connects the generation and transmission assets of the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers.

going forward. Taking advantage of technological advancements is one reason that we can deliver a Preferred Plan that achieves deep carbon reductions for a nominal customer cost of just over one (1) percent Compound Annual Growth Rate (CAGR) over the planning period. And over the long run, our Preferred Plan is expected to yield net present value savings – yielding $203 million of benefits on present value revenue requirements (PVRR) basis and $461 million of benefits on a present value societal costs (PVSC) basis.

D. Risk and Flexibility

Finally, we also seek to mitigate customer risk by ensuring fuel diversity, maintaining appropriate capacity length in our portfolio, and maintaining flexibility in our plans. Portfolio fuel diversity is essential to risk mitigation – especially so, as we transition away from coal. Incorporating a mix of nuclear, load management, intermediate and peaking natural gas capacity, and renewables into our long-term plans ensures that our portfolio is adequately diverse – mitigating the risk associated with overdependence on any one fuel source. Further, the proposed resource additions identified in our Preferred Plan result in a capacity position that is between 500-1,000 MW long in any given year. We believe this modest length is prudent, particularly as we propose to substantially increase renewable resources – adding more than 4,000 MW of incremental new renewable capacity, in addition to our already large wind fleet.

Both MISO and independent analyses suggest that capacity accreditation for solar in particular will decline substantially as more capacity is added. We expect MISO will ultimately recognize this conclusion from its ongoing study of issues associated with integration of high levels of renewables in its planning construct.[3] Therefore, what we believe today to be a long capacity position may actually erode over time.

Maintaining a significant amount of flexibility in our future plans is essential to reliably and affordably navigating the transition of our fleet. To that end, we are deferring a decision on pursuing a license extension at the Prairie Island nuclear plant to subsequent resource plans, thereby preserving flexibility to respond to market conditions at that time.

Underscoring all four of our objectives is our commitment to our employees and the communities within which we operate. We do not make plant closure decisions lightly, and we are committed to supporting our employees at the Sherco and King plants as we prepare to retire these facilities. We also know that the Company is a

[3] We discuss MISO's *Renewable Integration Impact Assessment* (RIIA) in more detail in our Baseload Study, provided as Appendix J1.

major presence in terms of employment and local tax revenues in Becker and Oak Park Heights and the surrounding areas. We also have partners at our Sherco site with Liberty Paper and SMMPA (Southern Minnesota Municipal Power Agency). We are currently participating, alongside Minnesota Power, in a Host Community Impact study, to better understand the potential impact of power plant retirements on host communities. We are committed to continue to work with our employees and communities to navigate this transition together.

IV. THE PREFERRED PLAN

To develop the Preferred Plan, we first developed a Reference Case plan that continues the path we set out in our 2015 Resource Plan, with respect to operation of our baseload generating units. This Reference Case provides an opportunity to at least achieve the carbon reduction goals set-out in our previous Resource Plan, while meeting our minimum system needs and compliance obligations. Our Reference Case provides a base line from which we measured the emission reduction benefits, renewable and other energy additions and estimated cost impacts of our Preferred Plan.

A. Determining Customer Needs

Determining our customers' needs for electricity is a key component of any resource plan, and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. To this, we forecast of customers' needs starts in terms of capacity, or peak demand, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

To this, we add a "reserve margin" prescribed by MISO, which is intended to cover potential uncertainties in the availability of resources or level of demand. We then subtract the resources we already have or expect to have, to determine our net surplus or need. We illustrate this concept and discuss each of the components below.

Figure 3: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

This analysis yields our net generation capacity surplus or deficit over the planning period, shown below:

Table 1: Reference Case Load and Resources[4]
2020-2034 Planning Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs (MW)															
Forecasted gross load	10,499	10,559	10,621	10,684	10,755	10,820	10,886	10,954	11,140	11,232	11,320	11,418	11,518	11,619	11,717
Forecasted EE[5] (reduction to load)*	(1,386)	(1,472)	(1,517)	(1,609)	(1,707)	(1,822)	(1,921)	(1,992)	(2,125)	(2,215)	(2,278)	(2,366)	(2,352)	(2,324)	(2,415)
Forecasted net load	**9,112**	**9,087**	**9,103**	**9,075**	**9,048**	**8,998**	**8,965**	**8,963**	**9,014**	**9,016**	**9,042**	**9,052**	**9,166**	**9,295**	**9,301**
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,657	8,633	8,648	8,621	8,595	8,548	8,517	8,514	8,564	8,565	8,590	8,599	8,708	8,831	8,836
MISO PRM	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
NSP Obligation	**9,384**	**9,358**	**9,374**	**9,345**	**9,317**	**9,266**	**9,232**	**9,230**	**9,283**	**9,285**	**9,312**	**9,321**	**9,439**	**9,572**	**9,579**
Reference Case resources (MW, unforced capacity)[6]															
Load Management *(existing)*	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management* *(potential study)*	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,390	2,390	2,390	2,390	1,699	1,699	1,699	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017
Nuclear	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	992	992	992	484
Natural Gas/Oil	3,295	3,295	3,295	3,295	3,141	2,829	2,624	2,136	2,018	2,018	2,018	2,018	1,765	1,765	1,765
MEC*	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sherco CC*	0	0	0	0	0	0	0	727	727	727	727	727	727	727	727
Biomass/RDF	110	110	110	86	86	63	63	63	22	22	22	22	22	22	22
Hydro	877	997	989	989	989	162	162	162	162	162	162	162	156	152	152
Wind	596	650	696	670	659	642	637	622	616	594	593	578	575	511	492
Grid-scale solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Solar*Rewards Community Solar	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Existing Resources	**11,267**	**11,486**	**11,571**	**11,559**	**10,746**	**9,634**	**9,460**	**9,040**	**8,913**	**8,905**	**8,920**	**8,311**	**8,066**	**8,026**	**7,521**
Net Resource (Need)/Surplus	**1,884**	**2,128**	**2,196**	**2,213**	**1,429**	**368**	**228**	**(190)**	**(370)**	**(380)**	**(392)**	**(1,010)**	**(1,373)**	**(1,546)**	**(2,058)**

From this point, the modeling underlying our resource planning identifies the best combination to meet any net resource deficiencies and the resulting energy mix.

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[4] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case.
[5] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels. Also includes minimal EV and coincidence adjustments.
[6] Unforced Capacity (UCAP) is a measure of resource adequacy value that we use in modeling to ensure we have sufficient resources to cover our full obligation. These values are discounted based on actual or expected average performance, per MISO, relative to the installed capacity values presented in our expansion plans.

B. Reference Case Expansion Plan and Energy Mix

Table 2: Reference Case Annual Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	0	1000	500	500	0	1000	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	232	374	374
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	1581
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	540	172	159	290	226	777	252	2,098	700	784	193	1,232	932	1,065	2,123

C. Developing the Preferred Plan

We use a modeling tool called Strategist, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analyses by individually changing key assumptions and re-running the plans under these changed assumptions.

Beginning with our Reference Case to meet our minimum system needs, we created 15 scenarios. Because one of our requirements with this Plan was to examine a potential schedule for a cost-effective and orderly retirement of baseload generating units not already scheduled to retire early (King, Sherco 3, Monticello, and Prairie Island Units 1 and 2), we performed technical studies as part of an overall Baseload Study that informed these scenarios and their costs.

These scenarios examined different combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs, achieve our 2030 carbon reduction goals, and maintain affordable rates. Key scenario groupings analyzed include:

- *Early Coal*. Analyses to evaluate the economics (i.e. revenue requirement impacts) of retiring King and/or Sherco 3 early.
- *Early Nuclear*. Analyses to test the economics of retiring Monticello and/or Prairie Island early, either alone or together and with the combination of early coal retirements.

- *Extend Nuclear.* Analyses to test the economics of re-licensing Monticello and/or Prairie Island and extending the operational life by ten years over the current retirement date.

Based on these analyses, we believe that our Preferred Plan meets all of our key planning objectives, positions us well to meet customers' needs, reasonably balances outcomes and costs – all while providing us with the necessary strategic flexibility to address the planning landscape.

D. Preferred Plan

Key components of our Preferred Plan include:

- ***Coal Resources*** – Retire our last two units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early). Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco Unit 2 into MISO on a seasonal basis until its retirement.
- ***Nuclear Resources*** – Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[7]
- ***Renewable Resources*** – While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period.
- ***Combined Cycle Resources*** – Acquire and operate MEC and build, own and operate Sherco CC to satisfy significant capacity and operational needs created by coal closures.
- ***Firm Load Supporting Resources*** – Starting in 2031, add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources by 2034.
- ***Demand Side Management*** – Include energy efficiency (EE) programs representing an approximately 780 GWh of savings annually through 2034 (compared to average annual energy savings of 444 GWh in our last Resource Plan) and the addition of 400 MW of incremental Demand Response (DR) by 2023, achieving a total of over 1,500 MW DR by 2034.

[7] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.

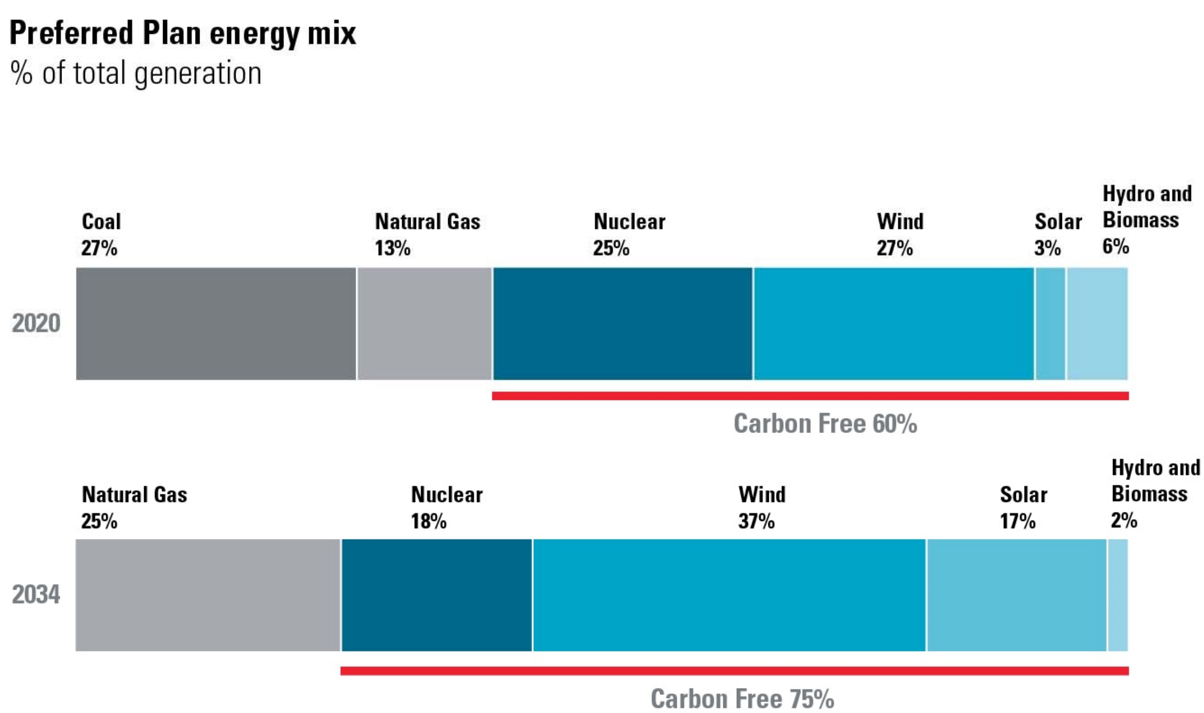
Table 3 below outlines the proposed timing, type, and size of resource additions comprising our Preferred Plan.

Table 3: Preferred Plan Resource Additions (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**290**	**226**	**777**	**752**	**2,098**	**700**	**784**	**693**	**838**	**700**	**1,065**	**997**

Our Preferred Plan outlined above would result in the energy mix shown in Figure 4 below.

Figure 4: Preferred Plan Energy Mix



Our Preferred Plan achieves several important goals:

Reliability. Our Preferred Plan maintains the safe and reliable service we have been providing for many years, and ensures that the NSP System has sufficient capacity and energy available during the planning period.

Environmental Outcomes. Implementing our Preferred Plan will allow us to reduce our carbon emissions over 80 percent from 2005 levels by 2030. Additionally, our Preferred Plan adds significant renewable energy to the NSP System.

Strategic Flexibility. Our Preferred Plan positions the Company well in the current planning landscape – meeting near-term needs and creating flexibility for the future. As we have described, planning constructs, policies, and technology costs are all creating uncertainty, which leads us to prioritize strategic flexibility in our plans to preserve the most value for our customers

Affordability. As discussed below in the Rate Impact section, we estimate that our Preferred Plan can be implemented at reasonable cost to our customers.

V. FIVE-YEAR ACTION PLAN

Our Preferred Plan does not identify any incremental capacity needs through 2024. Thus, our actions in the next five years primarily address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer needs, and continuing to achieve reductions in energy demand and load through ambitious DSM programs. We also plan to make targeted investments in supporting infrastructure to accommodate increased renewable energy and DER on the grid, and to gain operational experience with technologies that may play a larger role on our grid in the future. Key highlights are as follows:

Wind. We expect that the 1,850 MW of wind generation resulting from our recent acquisitions and RFPs will achieve commercial operation by 2022. We expect to replace wind capacity that will expire, and we are committed to pursuing repowering and/or contract extension opportunities for this capacity, as part of our "no going back" renewables strategy. Further, we intend to pursue incremental renewable resources as needed to meet customer needs in growing customer programs like Renewable*Connect.

Solar. Our Preferred Plan includes significant amounts of large scale solar, with the initial addition of 500 MW occurring in 2025 – just outside of the five-year Action Plan window. We expect to implement a competitive acquisition process in the 2023 to 2024 timeframe and bring these resources online by the end of 2025. On the distributed solar side, we have included forecasted growth in our plan. If actual distributed solar capacity additions exceed our expectations, we anticipate this will displace a portion of our proposed utility-scale solar resources.

Nuclear. Our Preferred Plan includes a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. While the license does not end until 2030, we expect to begin a proceeding with the Commission within the next five years and also begin working toward license extension with the Nuclear Regulatory Commission during this timeframe.

Natural Gas/Oil Peaking. We anticipate extending the life of Blue Lake Units 1-4 through 2020-2023,[8] which provides 153 MW of peaking capacity to the NSP System. Our Preferred Plan further includes our acquisition of MEC, which is currently pending Commission consideration. Finally, we plan to continue development activities associated with the Sherco CC during the next five years.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 2, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

Demand Response. Our Preferred Plan proposes to acquire 400 MW of DR resources by 2023.

Supporting Infrastructure. Aside from the grid-scale and DER additions included in our Plan, sufficient supporting infrastructure is essential to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. We expect further and substantial transmission infrastructure development will be necessary over the long-term, which will involve planning in the near-term. We also are continuing to refine our advanced grid strategy and intend to propose implementation of foundational grid modernization investments – and continue our work to integrate planning processes at all levels of the grid.

Resource treatment across states. We continue to explore options with the North Dakota

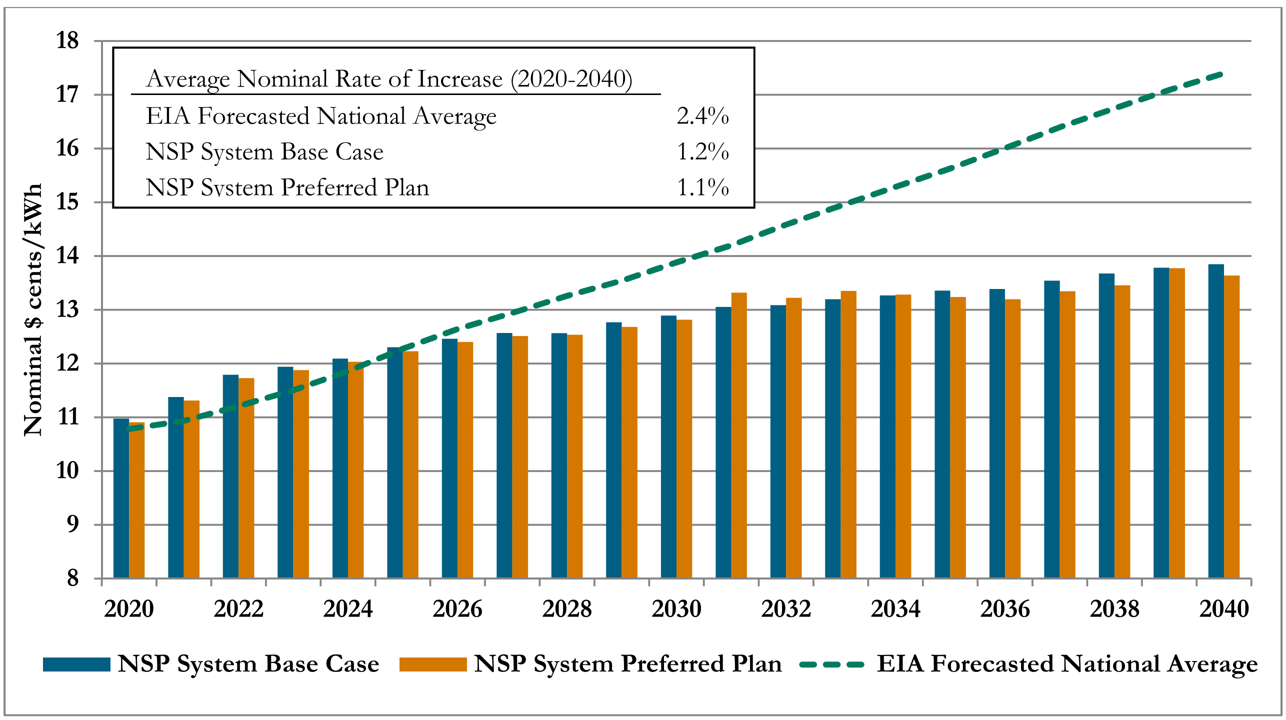
[8] Pending decision in Docket E,G002/D-19-161

Public Service Commission to create a resource planning process can more formally accommodate generation portfolio preferences. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address differing energy policies and changes in cost allocations that may result.

VI. RATE IMPACTS

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements less than the Reference Case and just over 1 percent overall. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly half the expected national average increase in electricity prices.
This is demonstrated in Figure 5 below.

Figure 5: Preferred Plan Average Nominal Cost Comparison NSP System



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[9] The Preferred Plan and Reference *Plan lines include the costs of Solar Rewards*Community.*

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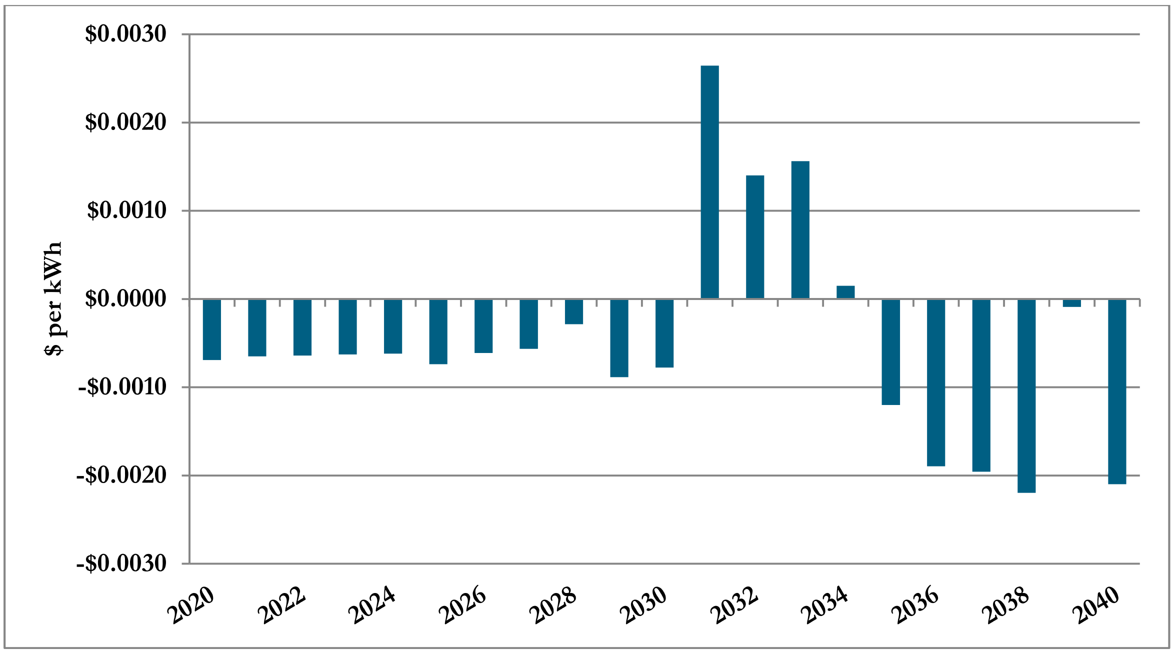
[9] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

Figure 6 below demonstrates the actual impact implementation of our Preferred Plan would have on our customers' bills. We note that the Preferred Plan's average estimated rate impact, relative to the Reference Case, in any given is well under $0.01 per kWh.

Figure 6: Incremental Rate Impact of Preferred Resource Plan State of Minnesota – All Customers



VII. CONCLUSION

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. Our Preferred Plan proposes to eliminate coal, add even more renewables, and continue our industry-leading energy efficiency and demand response programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. By planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, as discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.


Xcel Energy®
Building a Carbon-free Future
CARBON
REPORT

To our **Stakeholders:**

Xcel Energy is committed to serving customers, and that includes responding to the concerns of many customers around the risk of climate change. National and international studies paint a sobering picture about this risk and call for nothing less than a transformation of our industry to help address it. While that transformation will be challenging, we see an opportunity for our company and those we serve to significantly reduce greenhouse gas emissions reliably, safely and at a low cost.

In 2018, we reduced carbon emissions from the electricity that serves our customers by 38 percent compared to 2005 levels and plan to do even more. As technologies have improved and costs have fallen, we are making significant changes — more than we imagined possible a decade ago — without compromising the reliability or affordability that our customers expect. We need all three components — clean, reliable and affordable — to make this transition work.

As we carry out Xcel Energy's vision to be a preferred and trusted energy provider, leading the clean energy transition continues to be a strategic priority for us. It's helping to achieve our other two strategic priorities as well — to keep customer bills low and enhance the customer experience.

We're a national leader in wind energy and are harnessing it through our Steel for Fuel strategy, which we expect to reduce costs for customers. We also offer a leading portfolio of energy efficiency and renewable choice programs because an increasing number of customers want to power their homes and businesses with clean energy and take steps to reduce their own carbon footprints.

While our existing efforts are significant, we want to do even more and do it sooner than anticipated. That is why I set an ambitious vision to reduce our carbon emissions 80 percent from 2005 levels by 2030. Longer term, we aspire to serve our customers with carbon-free electricity by 2050. The technology to achieve this aspiration isn't commercially available yet, but I believe it can be available if we make it a priority today.

In this report, we discuss our vision, including the opportunities, risks and challenges we face getting there. We describe how our carbon transition can have an even larger impact in other sectors, such as transportation. We also show how our commitment compares to the targets of international climate agreements.

Xcel Energy is leading the clean energy transition. We know from experience that our goals are ambitious. This change will require collaborative, long-term solutions that are cost effective as well as advanced clean energy technologies. Broad stakeholder support, smart public policy and favorable economics are essential factors in this ongoing transformation.

We can't achieve this transition alone — it will take all of us working together. I look forward to your partnership.

Sincerely,

Ben Fowke
Chairman, President and CEO

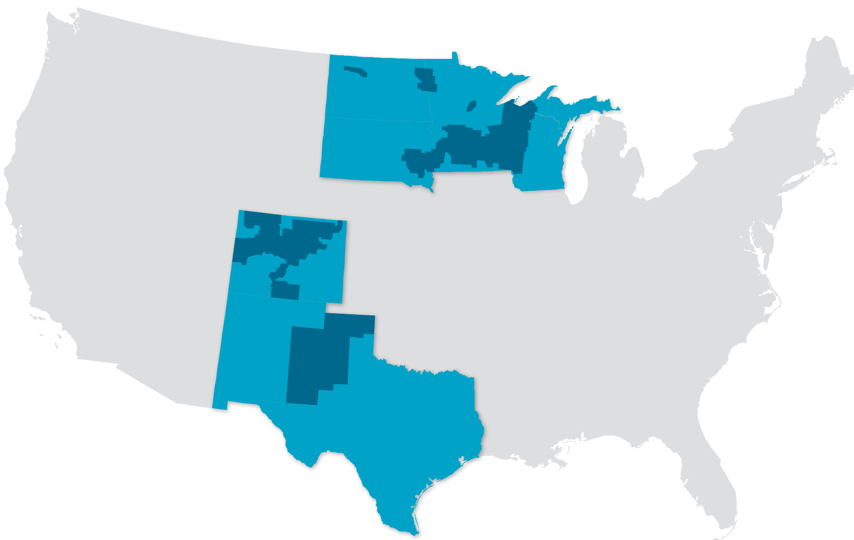
Contents

About Us

Xcel Energy is a major U.S. electricity and natural gas company with annual revenues of $11.4 billion. Based in Minneapolis, we operate in eight states and provide a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers.

Addressing climate change is a priority for many of our customers, investors and key stakeholders, and is a priority for us as well. In delivering on our strategic focus to lead the clean energy transition, we are successfully reducing carbon emissions and providing clean energy solutions from a variety of renewable sources, reliably and affordably for customers.

More information on our clean energy strategy, corporate governance and risk management is available at **xcelenergy.com** in our corporate reports, including Xcel Energy's Annual Report, Proxy Statement, Corporate Responsibility Report and EEI Environmental, Social, Governance and Sustainability Report.



Forward Looking Statements
The material in this report contains forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements include projections related to emission reductions, changes in our generation portfolio, planned retirements, and planned capital investments and are identified in this document by the words "aim", "aspire", "assuming", "believe", "could", "expect", "may", and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; business conditions in the energy industry: competitive factors; unusual weather; effects of geopolitical events; including war and acts of terrorism; changes in federal or state legislation; regulation; actions of regulatory bodies; and other risk factors listed from time to time by Xcel Energy in its Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018 (including the items described under Factors Affecting Results of Operations) and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC.

Aspiration for a **Carbon-free** Energy Future

For more than a decade, Xcel Energy has demonstrated leadership on clean energy — proactively reducing carbon emissions at levels that currently surpass state and federal goals. This environmental commitment is woven into our company's strategy, governance, executive compensation and daily operations.

To respond to growing stakeholder expectations, we have regularly established and achieved increasingly ambitious carbon reduction goals.

Where We Aim to Be

Our vision for the future includes industry-leading goals shown in Figure 1. In this report, we demonstrate how our goals align with an emissions trajectory needed for the electric power sector to meet the goals of the Paris climate agreement.

By 2030, we aim to reduce carbon dioxide emissions 80 percent below 2005 levels company-wide. This means that by 2030, our annual carbon emissions from the electricity that serves our customers will be about 17 million tons, or 80 percent lower than in 2005. We believe these emission reductions can be achieved cost effectively with continued fleet transition and operational changes, and with the renewable, carbon-free generation and energy storage technologies available today.

By 2050, we aspire to provide our customers across all states with 100 percent carbon-free electricity. In the next 30 years, we will transition to serve our customers with electric resources that emit zero carbon dioxide emissions. To fulfill this aspiration, we will continue to increase renewable energy sources on our system, as well as technologies that enable renewable integration. We will need new carbon-free dispatchable technologies — technologies not yet commercially available at the cost and scale needed to achieve our 2050 aspiration. Because of this, there needs to be significant research and development to ensure we have these technologies to deploy in the coming decades.

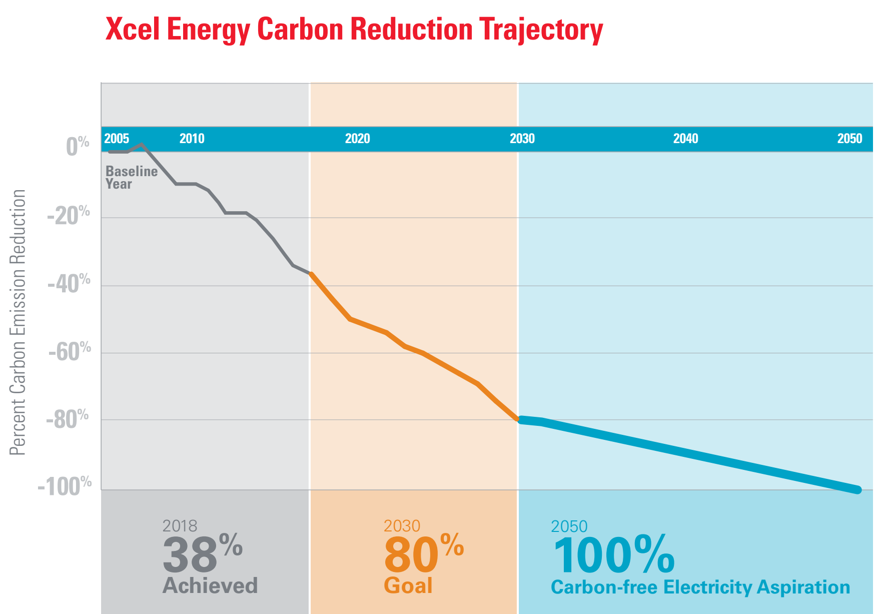


Figure 1: Our vision for the clean energy transition 2030 and 2050

The Path to Get There

We know that climate change is an urgent issue for many of our policy makers and a growing concern of our customers who want to help make a difference. Planning for the transition to a clean energy future today will allow us to deliver the product our customers want and achieve reductions that our policy makers are increasingly demanding. By acting now, we increase our chances to achieve these goals while assuring that our system remains reliable and our prices affordable. These last two points are critical to our success. The electricity we deliver is an essential service that powers the economy and keeps our customers comfortable and safe.

While we move through this transition, we need to make sure that power will be there when our customers need it and that the prices we charge are affordable to all customers , both residential and commercial. To accomplish this, we will build upon four focus areas that are transforming our system and delivering clean, reliable, low-cost power to customers today.

These focus areas include:

- Investing in wind and solar under our Steel for Fuel strategy and offering customers more renewable energy options
- Helping customers manage their energy usage and bills through efficiency and rebate programs and encouraging strategic electrification of other sectors, such as transportation
- Maintaining our carbon-free nuclear plants in the Upper Midwest
- Transforming the energy grid by retiring or reducing the operation of aging coal plants and replacing their energy with low-carbon natural gas, renewables and advanced technologies

Looking ahead to 2030 and 2050, we plan to continue this progress. Our vision is not a single plan or initiative. Instead, it will guide the policies that we support and the resource plans that we expect to file in our states over the coming decades. As we advance these efforts, stakeholders are essential and will help to influence the outcomes. Because of this, we plan to continue working collaboratively with customers, nongovernmental organizations, policy makers and others to identify and implement pragmatic solutions to make our goals possible.

In setting our goals, we did sensitivity analysis to identify key elements and variables that could affect our plans. There are a variety of cost-effective pathways to an 80 percent carbon reduction by 2030, and resource plans in our jurisdictions will determine the exact resource mix. However, through the pathways we explored, we have identified the following common elements that we know will be part of the plans:

- We anticipate adding thousands of megawatts of wind and solar power to our system and incorporating both natural gas and storage resources to help balance high levels of renewables
- Strategic electrification of certain end uses will help create flexible demand
- We will seek to operate our nuclear plants through at least the remainder of their licenses, and we will need to retire additional coal units or change their operations to minimize emissions affordably and reliably
- In addition, we will need to make critical investments in supportive infrastructure, such as transmission

As we transition our system and retire plants, we will need to assure that we do so in a way that our company remains financially healthy and that acknowledges the financial impacts of plant retirements and the replacement investment on our investors. Just as we serve other stakeholders, we must provide our investors with value to encourage them to provide the capital necessary to support these plans. There are many ways to accomplish our carbon vision, but the ability to own these replacement resources is clearly an important consideration, as investors support companies that grow their earnings power. This ownership also helps to reduce risk to customers and is fundamental to ensuring our financial viability and ongoing ability to efficiently invest in day-to-day infrastructure needs as well as clean energy.

To reach our 2050 aspiration, there must be more action around the research, innovation and demonstration of advanced technologies. We need, clean technologies that can be dispatched to balance the peaks when customer use exceeds renewable generation and valleys when renewable generation exceeds customer use. Cost-effective, low-carbon and carbon-free dispatchable resources will be required to remove the remaining carbon from the system to serve customers with carbon-free electricity. Technology advancement is key to the long-term success of our strategy.

Analysis Related to **Our Vision**

In planning our future carbon transition, we have reviewed the research on climate science to confirm the effectiveness of our goals. A trio of climate reports — from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program and the UN Environment Program — examine potential climate change impacts and the greenhouse gas reductions needed to meet the targets of the Paris climate agreement. While providing broad context for our analysis, none of these reports includes actionable guidance for utility decision making or for individual company greenhouse gas goals.

We also participate in an Electric Power Research Institute (EPRI) project that is analyzing the science around climate scenario analysis and emission goal setting. While providing useful insights about global, regional and electric sector emissions consistent with limiting temperature increases to 2 C, the EPRI project does not provide company-specific comparisons to the Paris climate targets.

To bridge this gap, we hired experienced climate modelers at the University of Denver to compare Xcel Energy's goals to the Paris climate targets. We compared our goals to electric power sector emissions in industrialized countries, in IPCC scenarios consistent with a high probability of achieving the 2 C and 1.5 C temperature goals in the Paris climate agreement.

The Paris Climate Agreement

In December 2015, the international negotiations of the United Nations Framework Convention on Climate Change (UNFCCC) produced the Paris climate agreement, with the goal of "holding the increase in the global average temperature to well below 2 C above preindustrial levels and pursuing efforts to limit the temperature increase to 1.5 C above preindustrial levels, recognizing that this would significantly reduce the risks and impacts of climate change."[1]

The Paris climate agreement does not establish goals, mandates or even guidance for individual economic sectors or companies. This makes it challenging to address the relationship between the agreement's goals and company-level targets. Its temperature goals represent a global ambition, pursued through nationally determined contributions and subsequent national and sub-national (e.g., state) policy decisions about how to allocate the emission reduction burden across sectors, industries and individual companies.

IPCC Special Report

The IPCC in October 2018 published a Special Report on Global Warming of 1.5 °C. The IPCC estimates that warming to date is about 1 C above average preindustrial temperatures and that warming is likely to reach 1.5 C between 2030 and 2052.[2] The report evaluates human and natural impacts of climate change associated with global warming of 1.5 C and compares these to impacts at 2 C or more. The IPCC then explores what global greenhouse gas reductions would be needed, on what timeframe, to limit warming to 1.5 C. It estimates that global net human-caused carbon dioxide emissions would need to peak within the next few years, then fall dramatically, reaching net zero by around 2050 (meaning that after that point, carbon emissions are balanced by carbon removal.) The report indicates that allowing global temperatures to temporarily overshoot 1.5 C, but return below 1.5 C by 2100, would require greater reliance on negative emission technologies after mid-century. To stay below or only temporarily exceed 1.5 C, global emissions in 2050 would have to be between 71 percent and 129 percent below 2010 levels.[3]

US Fourth National Climate Assessment (NCA4)

The U.S. Global Change Research Program in November 2018 released its Fourth National Climate Assessment, summarizing the latest scientific understanding of climate change impacts, risks, mitigation and adaptation, both nationally and by regions of the United States. The report finds that climate change is having significant impacts on U.S. communities, the economy, trade, water, public health, ecosystems, infrastructure, energy systems, agricultural productivity, oceans and coastlines. Potential impacts on the electric sector include reduced generation efficiency at thermal plants, power outages, grid reliability challenges, fuel transport, changing wind patterns, increased electricity demand for cooling and reduced natural gas demand for heating.

Under a high emissions future, NCA4 finds that "climate change is projected to impose substantial damages on the U.S. economy, human health and the environment. Under scenarios with high emissions and limited or no adaptation, annual losses in some sectors are estimated to grow to hundreds of billions of dollars by the end of the century."[4] However, NCA4 also finds that greenhouse gas reductions sufficient to keep the world on a lower warming pathway could still avoid or significantly reduce these damages — and that the earlier the reductions, the greater the chance of avoiding the worst impacts.

UN Emissions Gap Report

The U.N. Environment Programme (UNEP) in November 2018 released its annual Emissions Gap Report, which assesses the status of countries' "nationally determined contributions" under the Paris climate agreement. The report finds that global carbon dioxide emissions increased in 2017 after staying relatively flat for three years, reaching 53.5 billion metric tonnes CO2e (GtCO2e) and show no signs of peaking in the near term. Without additional efforts, UNEP predicts global warming of about 3 C by 2100. UNEP estimates a gap of 13 GtCO2e per year by 2030 between global emissions under the nationally determined contributions and the annual emissions needed to achieve the 2 C target (for the 1.5 C target, a gap of 29 GtCO2e.) UNEP finds it is still possible to bridge the gap and contain warming below 2 C and 1.5 C, but this will require aggressive reductions by 2030, particularly in emission scenarios that are more pessimistic about the potential for negative emissions (i.e., carbon removal technologies) later on.

EPRI Research

Because the reports summarized above do not include guidance specific to electric utilities or other industries, Xcel Energy also participates in a multi-utility project convened by EPRI to examine the current state of the science around climate scenario analysis and company greenhouse gas goals.[5] EPRI released a report in fall 2018 that takes stock of current scientific understanding and provides analytical guidance, titled Grounding Decisions: A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals. We outline here a few key findings from the report.

Figure 2 illustrates the many variables defining the relationship between global temperature goals and company-level greenhouse gas emissions. Uncertainties in the relationships between each variable result in ranges of global, country, sector and individual company emissions consistent with a temperature goal. This means there is no single or uniform target that can be applied to all companies and is appropriate in all plausible futures. Nonetheless, ranges can be identified that are consistent with achieving the temperature goals.

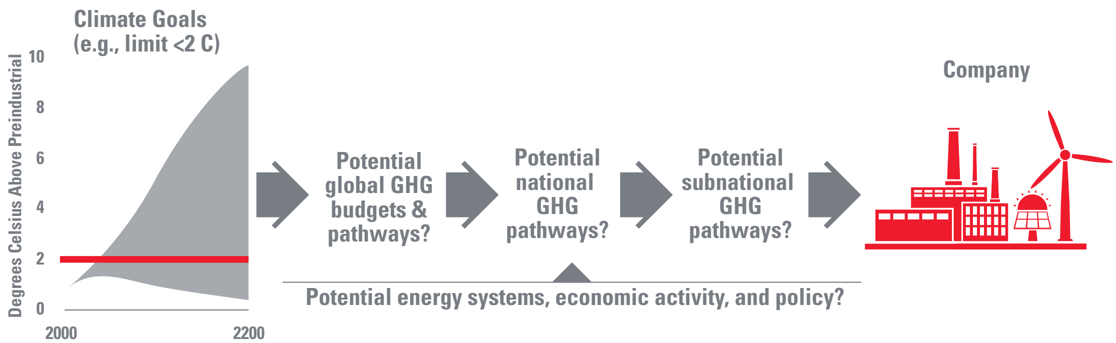


Figure 2: The relationship between global climate goals and company-level targets. Reproduced from EPRI 2018, page 2-1.

EPRI draws on the IPCC Fifth Assessment Report (AR5) emission scenario database and other scenarios to characterize current understanding of these relationships. Among other things, the EPRI study identifies sets of global, regional and electric power sector emission scenarios consistent with different probabilities of limiting global average temperature increase to 2 C.[6]

Figure 3, reproduced from the EPRI report, shows the range of global carbon dioxide scenarios consistent with a 40 percent or greater chance of limiting global warming to 2 C. The left-hand chart shows that a broad range of scenarios, rather than a single scenario, is consistent with this temperature goal. It also shows that scenarios that increase emissions in the near term generally require significant negative emissions after mid-century to offset the near-term increase and achieve the temperature goal.[7] The right-hand chart shows the much smaller range of scenarios that can achieve the temperature goal with the same 40 percent probability, if negative emissions technologies are unavailable.

The EPRI study also presents sets of regional and electric sector emissions pathways consistent with 2 C. However, as discussed by EPRI, these results are dependent upon global assumptions — in particular, global economy-wide policy design and technology availability assumptions that facilitate reducing carbon with electricity. These are important uncertainties for electric power companies to evaluate, and sub-global scenario results should be used with caution and with these uncertainties in mind.

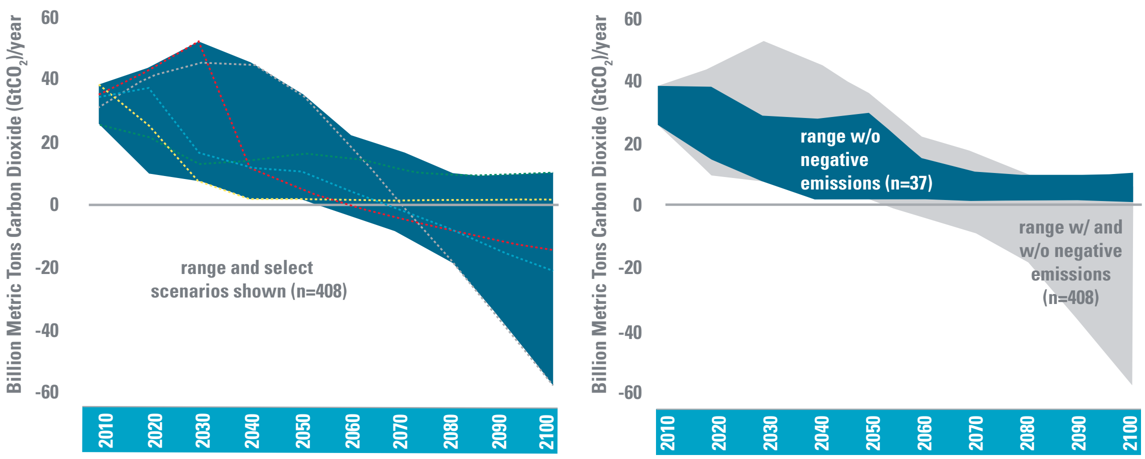


Figure 3: Global net carbon dioxide pathway ranges consistent with a 40 percent or greater chance of limiting warming to less than 2 C. Reproduced from EPRI 2018 and supporting material.

EPRI's report provided key insights for our subsequent work with the University of Denver. First, there is a broad range of emissions pathways consistent with a given probability of achieving a temperature goal. We need to consider our carbon goals relative to this range and the uncertainties it represents, including uncertainties about policy, technology availability and reductions assumed to be achieved in sectors other than electricity. Second, we can choose to compare ourselves to pathways with higher likelihood of achieving temperature goals, as well as compare to Xcel Energy to sub-global pathways such as electric power sector emissions. However, in doing so, it is important to recognize the assumptions, challenges and uncertainties embedded in such an analysis and their implications for our goals.

Finally, many IPCC scenarios assume the availability of significant negative emissions after mid-century, in some cases offsetting emission increases in the near term, to achieve the temperature goal. This is particularly true of the 1.5 C scenarios. Because negative emissions electricity technologies are not commercially available today, to be conservative we compared ourselves only to carbon scenarios that do not include negative emissions technologies within the electric power sector in industrialized countries (but may include negative emissions in other regions and sectors.) If negative emissions electricity technologies become available, we would consider them along with other options for providing customers reliable, affordable clean energy. Because our analysis does not rely on these technologies to reach our goals, we plan to continue to reduce carbon emissions aggressively in the near term, consistent with cost (which is also influenced by need) as well as reliability.

Comparing Xcel Energy to the Paris Climate Agreement Goals

EPRI did not attempt to identify company-specific emission trajectories corresponding to the global temperature goals because of the increasing uncertainty at higher levels of resolution. However, investors and others routinely ask Xcel Energy to compare company-specific emissions to the temperature goals, so we needed to go a step further. We commissioned an analysis by experienced climate modelers at the University of Denver, including a lead author on the IPCC's forthcoming Sixth Assessment Report, to compare our goals to electric sector carbon dioxide emission scenarios consistent with limiting warming to both 2 C and 1.5 C. We provided the modelers our carbon emission forecast and goals, and had them compare these to electric sector carbon emission scenarios consistent with 2 C and 1.5 C. We set three constraints on their analysis:

- Focus on scenarios categorized by the IPCC as having a high probability of achieving the temperature goals
- Compare Xcel Energy to the electric power sector in industrialized countries
- Exclude scenarios that rely on negative emissions technologies within the electric sector

On pages 11 to 13, the University of Denver modelers summarize briefly their approach and findings.

Xcel Energy targets and limiting warming to less than 2 C and 1.5 C

By Dr. Brian O'Neill and Steve Hedden

UNIVERSITY of DENVER

Climate researchers have carried out a large number of studies of how much and how fast greenhouse gas emissions would have to be reduced in order to achieve the Paris climate targets of limiting warming to less than 2 C, or even to below 1.5 C. We drew on the results of those studies to compare Xcel Energy's emissions reduction goals to emissions pathways consistent with the Paris climate targets. In those pathways, global carbon emissions generally decline to zero (in net terms) by around 2070 or later to stay below 2 C and by around 2050 to stay below 1.5 C.

However, emissions associated with one company in one country are just a fraction of global emissions, so we compared Xcel Energy's goals to a more detailed and more relevant set of results from these studies: net carbon emissions from the electric power sector in industrialized countries. We found that Xcel Energy's goals represent reductions that are consistent with, and in most cases larger than, those that occur in this sector in scenarios that achieve the Paris climate targets.

Approach

The Intergovernmental Panel on Climate Change report from October 2018[8] assessed the scientific literature on emissions scenarios consistent with the Paris climate targets. To support that assessment, researchers created a database of 416 published emissions scenarios.[9] The scenarios were developed using computer models that calculate the greenhouse gas emissions and warming that would result from the production and consumption of energy, food, transportation and other goods in regions around the world over the coming decades. The future is uncertain, so these scenarios investigate a wide range of possibilities about how fast population, incomes and energy demand may grow and what kinds of climate policies may be pursued to achieve the Paris climate targets.

We compared the Xcel Energy goals to a subset of these scenario results. First, we selected two sets of global greenhouse gas emission scenarios from the database: those that would be likely (defined as having a greater than 66 percent chance) to stay below 2 C, and those that would be more likely than not (defined as having a greater than a 50 percent chance) to stay below 1.5 C or to only slightly (and temporarily) exceed that level.[10]

Next, we extracted results from these scenarios for carbon dioxide emissions from the electric power sector in industrialized countries.[11] These outcomes from the scenario database are the best comparison available to Xcel Energy goals. Models that produce emissions scenarios do not represent individual companies, nor even individual countries. Results are reported in the database as totals for groups of countries for different sectors of the economy. By using results for the electric sector in industrialized countries, we can compare Xcel Energy goals to emissions pathways that occur on average across the same sector of countries at similar levels of economic development to the United States.

Finally, we excluded scenarios in which net carbon dioxide emissions from the industrialized country electric sector are negative at any time in the future, through 2100. (Note that these scenarios could still include negative emissions in other sectors and regions.) In the electric sector, net negative emissions could result from technologies like biomass energy with carbon capture and storage (BECCS) that generate electricity while removing carbon from the atmosphere. Scenarios with these technologies often allow for higher global emissions in the first few decades that are compensated for by negative emissions later in the century. However, these technologies are unproven at large scales and involve possible risks to biodiversity and food prices due to the large amount of land that may be required for growing biofuels.

Our selection process left us with 17 scenarios consistent with the 2 C target and five scenarios consistent with the 1.5 C target, a reflection that achieving the lower target without net negative emissions in the electric power sector is relatively uncommon in the scientific literature.

Results

The comparison in Figure 4 shows that Xcel Energy's 2030 and 2050 goals represent emissions reductions that are larger than those that occur in the electric sector of industrialized countries in most of the global emissions scenarios likely to limit warming to below 2 C. Xcel Energy's goals are also within the range of reductions that occur in the limited number of scenarios achieving the 1.5 C target. These figures show scenario results to 2050. Beyond 2050, these scenarios generally indicate low or zero net carbon emissions continuing through the end of the century.

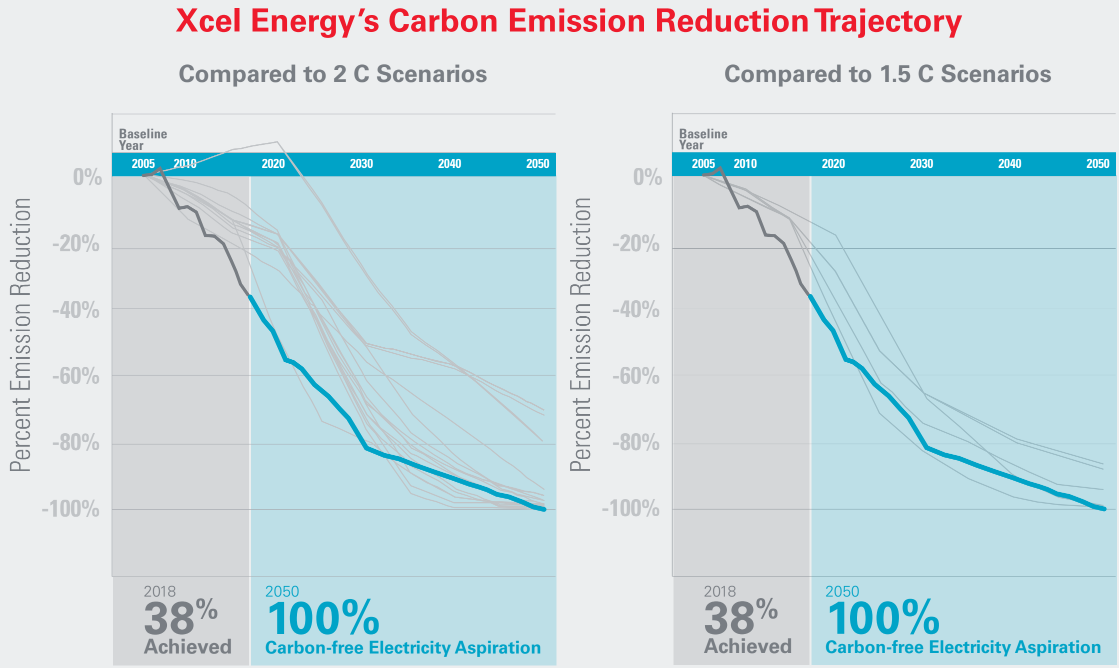


Figure 4: Xcel Energy carbon emissions reduction goals (in blue, with historical emissions in dark gray) compared to scenarios of emissions from the industrialized country electric power sector (in light gray). Emissions scenarios are from global scenarios likely to remain below 2 C warming (left) or more likely than not to avoid 1.5 C warming (right) without significantly exceeding that level. Emissions expressed as a percent reduction relative to levels in 2005.

Caveats to this analysis

To date, most company-level greenhouse gas scenario analysis has focused on 2 C rather than 1.5 C, in part because of the much greater uncertainty about the attainability of limiting warming to 1.5 C. The IPCC notes that limiting warming to 1.5 C may involve unprecedented actions.[12] Without taking a position on the attainability of 1.5 C, in this analysis we have assessed Xcel Energy's goals in relation to both temperature goals. We have chosen to include the 1.5 C scenarios because while that goal is unquestionably harder to attain than 2 C, experience shows that the scale and pace of technological change often outpaces our expectations today. Because of this — and because the IPCC Special Report makes clear that climate risks and damages, while not zero at 1.5 C, are substantively less than at 2 C — we believe it makes sense to include it in our analysis.

Any multi-decade analysis of company- or sector-level carbon dioxide emission trajectories relative to the global temperature goals involves inherently uncertain assumptions about economic growth, technologies, policy and global coordination or lack thereof. If those assumptions are not borne out — e.g., technologies do not develop as expected, economic growth is more carbon intensive than assumed, emission reductions (or negative emissions) assumed to occur in other sectors or regions do not materialize, etc. — then the industrialized country electric sector emissions consistent with a given probability of achieving the temperature goals could change.

We have endeavored to make conservative assumptions in this analysis. For example, we focus only on scenarios with relatively high likelihoods of achieving the temperature goals and exclude scenarios that rely on net negative emissions technologies within the electric sector. Also, we examined our conclusions to ensure that they do not change fundamentally when varying key assumptions, such as allowing net negative emissions in the electric sector, and that they do not rely on unreasonably large assumed reductions in other regions. For a fuller discussion of these issues, see our full report.[13]

Brian O'Neill is professor at the Josef Korbel School of International Studies at the University of Denver and director of Research at the Korbel School's Frederick S. Pardee Center for International Futures, whose mission is to explore, understand and shape alternative futures of global change and human development. He is currently a convening lead author for the IPCC's Sixth Assessment Report and was an author on the United States' Fourth National Climate Assessment.

Steve Hedden is lead system administrator at the Pardee Center and is a coordinating lead author of the United Nations Environmental Programme's (UNEP) sixth Global Environmental Outlook (GEO6.)

Our Conclusions on the Analysis

Participating in the EPRI research, and subsequently engaging University of Denver climate modelers to compare our carbon vision against the Paris climate targets, helped to validate that our goals are consistent with electric sector emissions in scenarios likely to achieve the targets. Our goal to reduce carbon emissions 80 percent by 2030 and aspiration to serve customers with carbon-free electricity by 2050 appear largely consistent with the industrialized country electric sector carbon reductions in scenarios that achieve the Paris climate targets, even acknowledging the many uncertainties and embedded assumptions in any such analysis.

More specifically, Figure 4 shows that our carbon dioxide reductions achieved to date (shown by the dark gray line) fall below all the scenarios corresponding to a high probability of achieving the 2 C and 1.5 C goals. Our trajectory from today to 2030 falls below all but one of the scenarios for both temperature goals. Our aspiration for 2050 lies well within the range of emission scenarios for both temperature goals. In addition, we note that our carbon dioxide emission reduction trajectory from 2030 to 2050 is represented as a simple straight-line projection since we have no resource plans that extend to 2050. Our actual reductions will not likely follow that smooth line and depending on cost and technology developments, and the future of our nuclear plants, could either decline or increase from the line in any given year.

Any climate scenario analysis has embedded assumptions and necessary simplifications. For our analysis, these include:

- Our actual carbon emissions will depend on our resource mix, renewable energy and natural gas prices, total load, degree of electrification of end uses currently reliant on other fuels, and many other factors. We typically run sensitivities for these and many other variables in our resource plans.

- Depending on the amount of electrification assumed, a very low-carbon electric power sector may enable significant greenhouse gas reductions in transportation, buildings and other sectors. Our strategy contemplates significant electrification of the economy. The scenarios shown here virtually remove carbon from the electric sector, but there could be scenarios in which it is cost effective for the electric sector to emit slightly more carbon while reducing carbon in other sectors and still achieving the economy-wide reductions necessary for the temperature goals.
- The cost effectiveness of any greenhouse gas reduction pathway depends to some extent on climate policy, which is not addressed here. If adopted, climate policy frameworks will determine costs to our customers, flexibility in achieving greenhouse reductions, and linkages to or coordination with other emitting sectors. Xcel Energy will continue to advocate for climate strategies that achieve greenhouse gas reductions at the lowest possible cost to customers while maintaining reliability. Since many IPCC scenarios envision significantly increased electricity use in transportation, buildings and industry in order to achieve economy-wide reductions, keeping electricity affordable will be crucial.
- The achievability and cost effectiveness of any greenhouse gas goal will also depend on how technology evolves, which we cannot predict for 2050 or even 2030. Our carbon transition will depend on a mix of renewable energy, energy storage, carbon-free dispatchable technologies and flexible demand that could enable us to achieve deep carbon reductions affordably and reliably.

Reporting and **Measuring Progress**

As an energy provider, we emit greenhouse gases as we provide electricity to our customers. The primary source of these emissions is from the combustion of fossil fuels to generate electricity, which makes up 99 percent of our total greenhouse gas emissions. Nearly all of our generation-related emissions are carbon dioxide. Because of this, it makes sense that we focus our strategy, goals and reporting on reducing carbon emissions.

The carbon emissions discussed in this report and other Xcel Energy reporting are from electric generating plants that we own and from electricity that we purchase from others. Xcel Energy sells a small portion of the electricity we generate into the market, and the carbon emissions from these off-system sales are excluded from our goal and goal reporting because the energy does not serve our customers. Also, it is likely that many companies purchasing the energy account for the emissions in their reporting, so including them in our reporting could result in double counting.

Our goal to reduce carbon emissions 80 percent by 2030 is based on absolute, company-wide emissions from the electricity that serves our retail and wholesale customers, measured from a 2005 baseline. Likewise, our aspiration to serve customers with carbon-free electricity by 2050 is company-wide.

Xcel Energy supports timely, transparent public reporting of carbon dioxide and other greenhouse gas emissions. Our comprehensive greenhouse gas reporting, from all parts of our business, is based on The Climate Registry and its Electric Power Sector Protocol, which aligns with the World Resources Institute and ISO 14000 series standards. Our company joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions.

Managing the Risks Associated with **Climate Change**

Over the next several decades as we make our carbon transition, we will continue to monitor and take steps to mitigate any risks along the way. Changing weather patterns, extreme weather conditions and other events, such as flooding, droughts, wildfires and snow or ice storms, can all impact our system in terms of system operability, customer demand, revenues, cost recovery and the health of regional economies.

We rely on routine business processes to identify and address these types of risks and emerging challenges. These include our risk management, resource planning and daily operations, as well as our continuous improvement and innovation initiatives.

Integrated Risk Management

Our integrated, multi-disciplinary risk management process creates accountability for managing risk across the company — from employees who are responsible for business compliance and adhering to our Code of Conduct, to senior executives and the board of directors who oversee risk management. Annually, executive leadership conducts a key risk assessment, considering materiality, timing and likelihood and controllability of risks. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. While the assessment is broad, it includes the operational, policy and weather-related risks potentially associated with climate change. Findings are presented to the board of directors, which assigns oversight of critical risks among the board's four standing committees to ensure they are well understood and managed on an ongoing basis. We provide more information on our risk management process, including discussion of climate-related risks, in Xcel Energy's annual form 10-K.

Resource Planning

Our resource planning process is designed to manage capital-intensive investments over decades-long time horizons. Through this regulated process, we evaluate a range of scenarios and stress test our energy portfolio against important variables, including fuel prices, renewable energy and storage costs, transmission constraints and a variety of others. We use load forecasts to account for changing weather patterns, a key variable in explaining actual loads and in forecasting future loads. Load forecast sensitivities can also ensure our portfolio is sufficient to meet different needs created by electrification, which is likely to become more prevalent in a carbon-constrained future. Our resource planning also considers the costs and risks of potential carbon regulation and potential damages from climate change by applying a carbon proxy, allowing regulatory costs, and in some cases, externality damages to be considered in selecting resources.[14]

Operations

Maintaining reliable and resilient operations across generation, transmission and distribution means we constantly prepare for the unexpected. We use a suite of techniques to maintain a resilient system from water management to emergency preparedness. For example, our Monitoring and Diagnostics Center watches the operation of major generating units in real time, identifying potential issues before they occur. We also have predictive analytics and software tools that help avoid plant failures and can even address issues which may result in higher emissions or compromise reliability. Further, we have specific procedures in place to deal with extreme weather, flooding, drought or other conditions that may impact the operability of our plants. To better understand and address climate-related vulnerabilities on our system, we joined the Department of Energy's Partnership for Energy Sector Climate Resilience to work with others in the industry.

A Focus on Grid Resiliency

We continually invest and innovate to maintain and improve the resiliency of our energy grid. The following are several highlights from the many programs we are implementing to address potential system risks.

Under our Advanced Grid Intelligence and Security (Advanced Grid) program, we are upgrading the energy grid to better serve customers and enhance our ability to efficiently restore power and improve reliability. The program builds a platform that provides enhanced visibility and control of the energy grid through the integration of modern information system technology and traditional distribution systems.

In addition to maintaining emergency plans at all of our power plants and planning for extreme weather, we are also focused on successfully managing major storm events, responding quickly and providing information to customers as we restore service. The Edison Electric Institute has recognized Xcel Energy multiple times with its Emergency Recovery Award for outstanding storm response. These efforts extend beyond our service territory, with our crews on standby to help with recovery efforts across the country when hurricanes or other natural disasters strike.

To better integrate high levels of renewable energy, we have deployed sophisticated modeling tools to better dispatch our system. Working with the National Center for Atmospheric Research and its affiliate company Global Weather Corp., we helped develop the Wind WX system that utilities around the globe now use to make better commitment and dispatch decisions. It uses real-time, turbine-level operating data and applies sophisticated algorithms to forecast the amount of wind power that will be produced. Forecasts for a 168-hour period are provided every 15 minutes across Xcel Energy’s entire service territory. As we integrate more solar on our system, we are working on similar innovations for solar forecasting.

Our vegetation management program is generally performed on a four- to five-year cycle for our distribution and transmission lines. In Colorado, we have established a Mountain Hazard Tree Program that helps us stay ahead of the tree mortality caused by Mountain Pine Beetles.

Since we provide electricity in drought-prone areas, water is a precious resource that we must carefully manage. A co-benefit of our transition to renewable energy is that we are also lowering our water footprint. Beyond this, we have a comprehensive water management program to minimize the risks of continued water usage, including innovative partnerships to access water during extreme drought periods. For example, we use treated effluent to cool power plants in Texas and New Mexico. This effluent is water that would otherwise not be used and is available during drought.

Opportunities to Lead the **Carbon Transition**

Utilities can play a key role in helping solve the challenges of climate change. According to the Energy Information Administration, the electric power industry collectively reduced carbon emissions 28 percent from 2005 to 2017.[15] This includes Xcel Energy's progress — having reduced emissions 38 percent already, we have plans underway to achieve more, as explained in this report.

As an industry leader in renewable energy and reducing carbon emissions, we have a strategic advantage in continuing to lead this transition. We have been able to provide scalable solutions to reduce the carbon footprint of the energy we provide, while continuing to deliver energy in a manner that is safe, reliable and affordable. As we continue to implement solutions to address emissions across our system, we can also provide customers with options to reduce their carbon emissions and help other sectors reduce carbon through strategic electrification.

Investing for the Future to Reduce Emissions

We must achieve our carbon transition while maintaining a modern, viable electric system, which is dependent on our ability to attract capital and investors. Transitioning to cleaner sources of energy to achieve our carbon reduction goals should consider utility ownership of replacement resources, as we need our investors to support this transition. Our capital plans also envision the need for additional transmission and advanced grid technology. By investing in these assets, we can improve service to our customers, introduce new options and support greater reliability and flexibility in the way energy is delivered. This financial component is important to our plans.

Xcel Energy operates in regions with some of the best wind and solar resources in the United States, and we are capitalizing on this. Our Steel for Fuel strategy calls for adding renewable resources at a net savings because the capital costs of projects are more than offset by future avoided fuel costs. Customers benefit from the clean energy that also helps to keep their electricity bills low.

These renewable projects are just one component of the resource plans that determine new investments. Through the resource planning process with state regulators, we develop comprehensive, cost-effective plans to transform our system, serve customers and advance our transition to clean energy.

Empowering Customers to Reduce Carbon Emissions

We know customers want cleaner energy and more renewable options, but also expect electricity that is affordable and reliable. The great advantage of our system-wide clean energy transition is that all customers are receiving lower-carbon electricity over time — our reductions are their reductions — at an affordable cost.

Some of our customers — from residential customers to corporations and cities — desire to go further faster, accelerating the system transition by setting goals to meet up to 100 percent of their own demand with renewable electricity or to reduce their overall emissions. To meet this demand from customers, we provide an increasing array of voluntary renewable choice products, including cost-effective options to procure up to 100 percent renewable electricity and a comprehensive portfolio of industry-leading energy efficiency programs.

Through our 2030 and 2050 carbon reduction vision, we can further help customers achieve their goals. They will continue to reduce the portion of emissions from their electricity consumption, while we transition our overall system to a diverse mix of cost-effective, low-carbon and carbon-free generation resources.

In addition, we expect that our planned investments in technologies to modernize the energy grid will enable us to deliver new solutions for customers and create a flexible energy grid that allows for two-way power flows from customer-connected devices or distributed energy resources.

Electrification of our Economy

As the nation's electricity supply becomes cleaner, attention has increasingly turned to other sectors of the economy to address climate change.

The transportation sector is now the nation's leading source of greenhouse gas emissions according to the Energy Information Administration.[16] This also applies to the states Xcel Energy serves. For example, data from Minnesota indicates transportation has surpassed electricity as the leading carbon emitter, and that carbon emissions from transportation are declining far slower than electricity — a clear indicator of the opportunity for transportation electrification.[17]

We believe that strategic electrification of certain end uses will be a key component — though not the only solution — for achieving economy-wide greenhouse gas reduction goals. If we continue to electrify transportation and power vehicles with carbon-free electricity by 2050, we can help address the climate challenge for that sector.

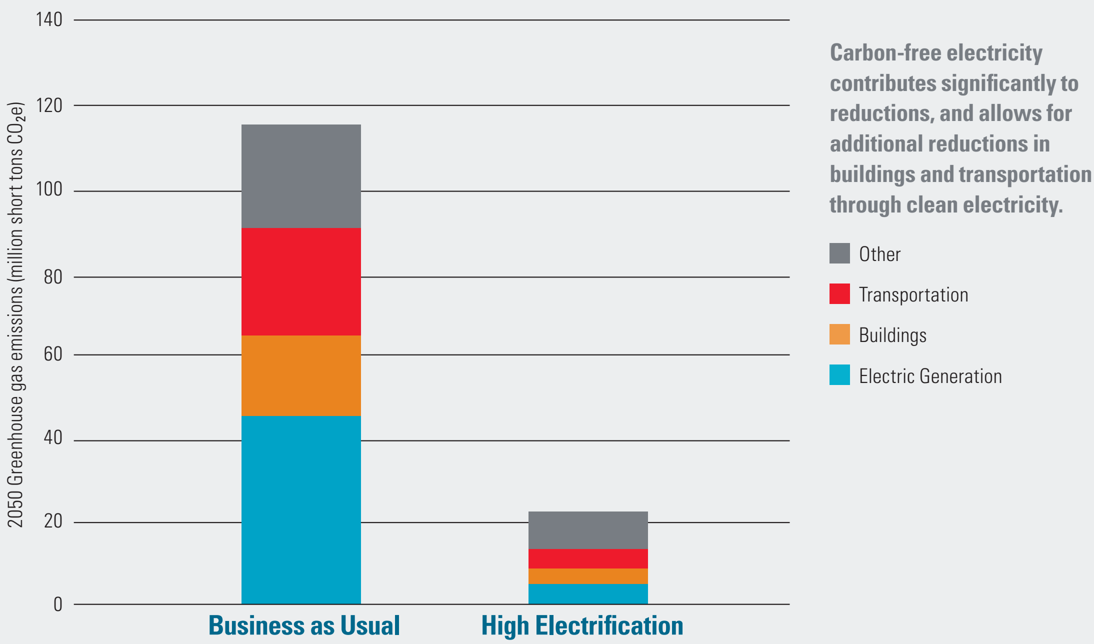
Low-carbon electricity and electrification: a Minnesota example

Removing carbon from electricity and electrifying other parts of the economy can be mutually reinforcing. Low-carbon electricity allows transportation, buildings and other major emitting sectors to reduce emissions. At the same time, flexible loads, such as electric vehicles and appliances that can charge at times of high renewable generation, may allow us to integrate more renewable resources than we could otherwise.

Xcel Energy engaged Energy+Environmental Economics (E3) to explore the feasibility of deep carbon reductions, both for the Xcel Energy system and for Minnesota statewide. E3 created a Minnesota PATHWAYS model looking at how the state could achieve its statutory economy-wide goal to reduce greenhouse gas emissions 80 percent from 2005 levels by 2050, with a primary focus on electricity, transportation and buildings.

The chart below illustrates this potential, focusing on 2050. It compares a business-as-usual scenario in which carbon is not reduced from electricity, and there is little or no electrification of other sectors, to what could be achieved in a "high electrification" scenario designed to meet the state's economy-wide 80 percent reduction goal. In this scenario, virtually all vehicles, space heating and water heating switch to electric alternatives by 2050. To supply these new loads, total statewide electricity demand in 2050 is 60 percent higher than 2015. Meanwhile, the electric sector reduces carbon, supplying over 90 percent carbon-free electricity in 2050. As a result, direct carbon emissions from electricity are reduced by about 40 million tons, as shown by the blue bars. Emissions from buildings, transportation and other sectors also decrease dramatically, with electrification enabling 35 million tons of that reduction through low-carbon electricity. Just as electricity is an essential service, natural gas service is as well, as it plays a critical role in keeping our customers comfortable and safe. When we review these options, we need to keep the affordability of space heating a primary objective along with the affordability of our electric business.

Carbon Reductions in the Electric Sector Drive Compounding Reductions throughout the Economy



Credit: Energy+Environmental Economics.

Xcel Energy's Electric Vehicle Strategy

The future of transportation is dramatically changing to include more electric-powered transportation options than ever before — as well as more autonomous features in vehicles and new (often shared) mobility services. Utilities are uniquely positioned to work with customers, communities and electric vehicle (EV) stakeholders to ensure this change benefits all customers, the environment and the energy grid that we all rely upon.

Through our current EV strategy, we are focused on:

- Making it easier for customers — from individual households to public and private sector fleets — to adopt EVs
- Creating the infrastructure needed to charge EVs
- Establishing time-varying rates and technological controls to ensure that EVs can charge as much as possible on low-cost, low-carbon energy

While EVs create a significant opportunity for drivers and fleet operators to save on fuel and other costs, barriers exist to wider-scale adoption, such as customer awareness, high up-front costs and the availability of charging infrastructure. Our plans will help overcome these barriers by developing new services, piloting them and then rolling out our most successful ideas to customers on a broader scale.

In Minnesota, we are engaging customers who are interested in adopting electric vehicles and buses. We hope to better understand their needs and barriers to adoption so we can work collaboratively toward solutions that could benefit all customers down the road. We expect these discussions will provide opportunities for us to pilot a variety of solutions that will inform our stakeholders and policy makers so we can scale solutions best suited to benefit all Minnesotans in the coming years.

As we pursue our EV Plan, we are focused on these objectives:

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

Driving **Change**

By mid-century, we aspire to serve customers with carbon-free electricity. Even though this goal is decades away, we are a long lead time business and should begin now to identify and address the barriers to reaching it — especially if we are to maintain the affordable, reliable service that customers need and expect.

After reviewing national and international studies on climate change and through our going work with stakeholders, we believe reducing carbon emissions reliably and affordably is a top priority and must be the primary focus of our clean energy transition. To effectively achieve this shared objective, we must remain disciplined and concentrate on those efforts that produce the greatest carbon reductions at the lowest cost to customers.

We are optimistic that by staying focused we can make this transition and have identified the following drivers that will make the change possible:

- Protect energy reliability and affordability
- Support from our states and stakeholders
- A constructive policy environment and framework
- Availability of cost-effective, carbon-free dispatchable technologies

While our vision is ambitious, we believe these drivers implemented together will make it possible to transform our operations and the industry overall. Our plan is to continue working proactively and collaboratively in all these areas and to advance the solutions that emerge.

Protect Energy Reliability and Affordability

Cost is a major consideration for our clean energy strategy, and so far, we have successfully reduced carbon emissions while keeping energy costs low for customers. In fact, the average Xcel Energy residential customer electric bill has decreased 3 percent in the past five years. Our residential electric bills are on average about $28 lower per month than the national average. In our largest service territories, Minnesota and Colorado, customer electric bills are 22 percent and 36 percent below the national average respectively. We must continue to develop and invest in cost-effective transformative plans and in technologies with proven economic value for customers.

Energy reliability is also a fundamental requirement. Today, we are achieving far greater levels of renewable energy on our system than the industry ever believed possible. There are hours on our system when renewable generation delivers more than 50 percent of customers' electricity, and at the end of 2018, we achieved an hourly renewable generation record of 72 percent on our Colorado system. We expect these hourly records to increase under our current plans, we project that renewables will generate almost half of our power on an annual basis by 2021. As we deploy more renewable energy resources, managing the stability and reliability of the energy grid becomes increasingly difficult with fewer resources that can be dispatched to manage the variability of wind and solar energy. We will be focused on how to make sure that we take care to have sufficient resources to meet swings in load and generation as our integration of more renewable energy becomes more challenging.

Support from our States and Stakeholders

By working with the states we serve, we have successfully executed our clean energy strategy and plans.

Our four operating companies work under regulated conditions largely determined by state public utilities commissions. Every few years, we go through a process to determine the resources necessary to serve customers' future energy needs. This state resource planning process is critical to ensuring reliable energy and maintaining reasonable customer bills. Our carbon vision is not a single resource plan. Implementing our clean energy transition and achieving our goals will happen through many iterations of resource planning before our state utilities commissions between now and 2050.

Stakeholder participation is an important component to resource planning, and stakeholder support is essential to our clean energy progress. We will continue constructive engagement with our customers, investors, regulators, environmental groups, community leaders, policy makers and others to develop solutions and implement plans to achieve our goals.

We believe this model of state leadership can go even further in driving cost-effective emission reductions and clean energy investment. If advanced, federal policy should encourage utilities to work with states and invest as the conditions are right — when customers and the economics and technology are ready and without imposing significant, unnecessary costs on utility customers.

A Constructive Policy Environment and Framework

We are proving that the vertically integrated utility model with regulatory oversight is a cost-effective way to transition the energy system and achieve significant carbon reductions. This model provides inherent system value through efficiency, optimization and economies of scale that benefit all customers. It also balances the allocation of risks and benefits between the utility, its customers and even different customer classes.

Every customer on the energy grid shares in the transition to clean energy and can credibly claim the same carbon reduction. Policies that enable large businesses to sign direct contracts with renewable developers, may help individual companies to achieve their goals. However, they do not provide all customers with affordable, carbon-free energy and may even result in a more expensive energy system overall.

We have seen remarkable examples of the transformation that is possible and know from experience that our ambitious carbon transition is achievable if stakeholders and policy makers continue to recognize the economic and environmental benefits that utilities provide. As we continue this transition and go above and beyond in reducing carbon emissions, there may be opportunities to provide appropriate incentive to encourage and reward the industry's progress toward carbon reductions economy-wide.

Large-scale, universal resources — conventional, renewable and advanced — are by far the most cost-effective electricity generating resources available. While distributed energy resources are important for customers who want to invest in them and may play important roles at the distribution system level, these resources cannot accomplish what large-scale resources do in terms of carbon reduction at scale. Public policy should recognize the economic benefits that large, universal resources provide to achieve our ambitious goals affordably and reliably for customers. Hidden and unfair subsidies to support high-priced resources only serve to increase the cost of clean energy and reduce the ability of the nation to make this transition.

Similarly, nuclear generation plays a vital role in our carbon transition and provides a significant portion of our carbon-free energy in the Upper Midwest. We need policies at the state and federal levels that allow us to continue the cost-effective operation of these important assets at least through the end of their current operating licenses.

We must also address emissions from fossil plants, especially from our remaining coal generation. We need policies that support coal operations which reduce emissions and offer investment recovery for the remaining value of coal plants which retire early. We also need help to minimize the impact on communities that depend on these plants.

All of these resources belong to the larger energy grid, which is enabling our carbon transition. As stewards of the grid, utilities own, operate and maintain this asset; raise and deploy capital to finance its growth and operation; and work with regulators to manage the risks associated with investments made on behalf of customers. Regulatory policy should ensure utilities continue to perform these critical functions to maintain the reliability, security and resilience of the energy grid during this transition.

Availability of Cost-effective, Carbon-free, Dispatchable Technologies

New cost-effective technologies have enabled our company and industry's progress in transitioning the nation's generating fleet and reducing carbon emissions. For at least the next decade, existing wind, solar, battery and natural gas technologies will continue to serve a growing portion of our energy needs while reducing carbon emissions and saving our customers money.

However, renewable generation and storage alone face significant technical and economic challenges if relied on exclusively to achieve carbon-free electricity. For example, the relatively short duration energy storage available today and anticipated in the future does not address seasonal challenges that arise when a system dependent on renewable resources experiences several days or weeks with low wind or solar generation. Even with continually declining prices, variable wind and solar resources are expected to provide diminishing value at high saturations. Fully relying on renewable sources could result in a costly overbuilding of the system where each incremental megawatt provides less capacity value, renewable curtailments reach high levels and massive investments in transmission and storage are required.

We need a suite of new, carbon-free resources that can be dispatched to complement our continued adoption of renewable energy, energy efficiency and demand response. Our research shows that these new resources will be the key to achieving a carbon-free generation fleet without a costly overbuilding of the energy grid. Others studying this issue have reached similar conclusions, including the MIT Energy Initiative, Energy+Environmental Economics and Vibrant Clean Energy.[18] These technologies may include carbon capture and storage, power to gas, seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal and others not yet imagined.

Each of these options holds promise, but they will require considerable investment and further research and demonstration to become viable solutions at the cost and scale at which the electric sector will need them. Federal and state policies must support this development. We can also send clear signals to the market around price, capabilities and timing for when these technologies will be needed. In this way, utility resource plans provide the market signal — the "technology pull" — from which the private sector and national laboratories and federal agencies can align their investments, research and assets.

Conclusion

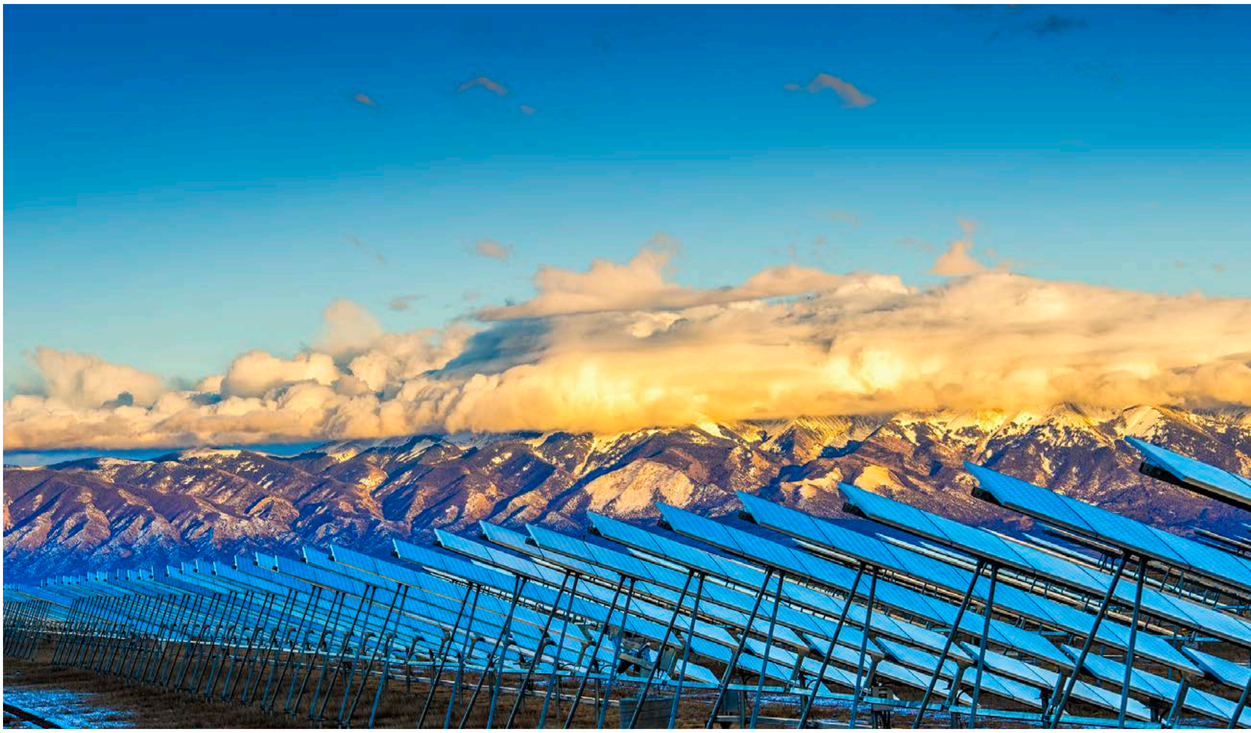
The finish line is clear — we aim to serve all customers by 2050 with carbon-free electricity. Through our analysis with the University of Denver, we are confident that both our interim and 2050 goal are the right goals for our customers but also to help limit warming to 2 C and possibly even 1.5 C.

Our vision is just the start. We will begin work now even though 2050 is decades away. Today, the technology and market exists to reach our interim goal and reduce carbon emissions 80 percent by 2030, but significant changes are needed to achieve reliable, affordable carbon-free electricity to serve our customers. We look to our partners to help us drive the advancements in technology and constructive policy to make it happen. While there may be differences of opinion around the details of how we get there, we are all in the same race together to reduce and eventually eliminate carbon.

Reducing carbon emissions should be the ultimate and shared objective. We must remain focused on this outcome and the drivers that will get us there as efficiently and cost effectively as possible.

As we work to make this vision possible, we will position our company and customers for success in a low-carbon future and provide greater long-term value for all stakeholders. We believe we can manage both the risks and capture the opportunities presented by this transition, and in the end, provide what our customers and other stakeholders want and need from us.

We are optimistic that through collaboration and with ingenuity and innovation, we will realize our vision for a carbon-free energy future.



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1 A summary of the Paris climate agreement, ratification status and text of the agreement are available at https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.

2 IPCC Special Report, Summary for Policymakers, page SPM-4.

3 IPCC Special Report, Summary for Policymakers, pages SPM-15 to SPM-24, and EPRI analysis of IPCC Special Report.

4 U.S. Global Change Research Program, Volume II: Impacts, Risks, and Adaptation in the United States - Report-in-Brief. Chapter 29, Reducing Risks through Emissions Mitigation, page 168. Available at https://nca2018.globalchange.gov.

5 EPRI is a non-advocacy, nonprofit, scientific research organization with a public benefit mandate. See http://eea.epri.com/ and www.epri.com/sustainability to learn more about EPRI's efforts to better understand the technical dimensions of company climate scenario analysis and GHG goal setting.

6 EPRI focused on the 2 C goal because the IPCC's AR5 database is the largest source of peer-reviewed scenarios available with over 1,000 scenarios. The IPCC Special Report on Global Warming of 1.5 °Celsius, and accompanying emission scenario database, were not available at the time EPRI began its work. As discussed in the EPRI study, 2 C pathways are extremely challenging — geophysically, technologically, economically, and politically — which creates uncertainty about their attainability. Uncertainty about the attainability of 1.5 C pathways is even greater.

7 Negative emissions technologies include biomass energy with carbon capture and storage, large-scale afforestation, direct air capture or other technologies yet to be developed. All face significant technology, cost, land use and social constraints at present.

8 IPCC, 2018: Global warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [V. Masson-Delmotte, P. Zhai, H. O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J. B. R. Matthews, Y. Chen, X. Zhou, M. I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, T. Waterfield (eds.)]. In Press. Hereafter, "IPCC SR 1.5 C."

9 Huppmann, D. et al. IAMC 1.5°C Scenario Explorer and Data hosted by IIASA. Integrated Assessment Modeling Consortium & International Institute for Applied Systems Analysis, 2018. doi: 10.22022/SR15/08-2018.15429 | url: data.ene.iiasa.ac.at/iamc-1.5c-explorer.

10 These categories follow the grouping used in the IPCC report in ref. 1. The lower likelihood of achieving the target in the 1.5 C case (50 percent) is used because of the difficulty of achieving it with higher likelihood. "Slightly exceeding" the target is defined as staying below 1.6 C.

11 We use the phrase "industrialized countries" to refer to the region defined in the IPCC database as "OECD90+EU," which contains countries that were members of the OECD as of 1990, as well as current EU member countries and candidates. Note this does not include Russia and other members of the Former Soviet Union (the "REF" region in the database). Specific countries included are: Albania, Australia, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Canada, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Malta, Macedonia, Montenegro, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States of America.

12 See IPCC Special Report, Summary for Policymakers, page SPM-21: "Pathways limiting global warming to 1.5°C with no or limited overshoot would require rapid and far-reaching transitions in energy, land, urban and infrastructure (including transport and buildings), and industrial systems (high confidence). These systems transitions are unprecedented in terms of scale, but not necessarily in terms of speed, and imply deep emissions reductions in all sectors, a wide portfolio of mitigation options and a significant upscaling of investments in those options (medium confidence)… The rates of system changes associated with limiting global warming to 1.5°C with no or limited overshoot have occurred in the past within specific sectors, technologies and spatial contexts, but there is no documented historic precedent for their scale (medium confidence)."

13 Xcel Energy carbon emissions targets and limiting warming to less than 2 degrees C. Brian O'Neill and Steve Hedden, December 31, 2018. Frederick S. Pardee Center for International Futures - Josef Korbel School of International Studies at the University of Denver.

14 Under integrated resource planning statutes in Minnesota, utilities must apply both a range of proxy prices for future carbon dioxide regulatory costs, and ranges for externality damages for carbon dioxide and other pollutants. Under Colorado public utilities commission rules, utilities apply carbon dioxide regulatory costs; there is no general requirement to apply carbon dioxide externality values, but Xcel Energy in its latest Electric Resource Plan cycle was ordered to include a sensitivity using an externality value.

15 See https://www.eia.gov/todayinenergy/detail.php?id=37392.

16 See https://www.eia.gov/totalenergy/data/monthly/, Environment section, and compare tables 12.5 and 12.6. Transportation CO_2 emissions surpassed electricity in 2016 and remained higher in 2017 and the first nine months of 2018.

17 Minnesota Pollution Control Agency, January 2019. Greenhouse gas emissions in Minnesota: 1990-2016. Page 6. Available at https://www.pca.state.mn.us/sites/default/files/lraq-2sy19.pdf.

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APPENDIX F1 – LOAD AND DISTRIBUTED ENERGY RESOURCE FORECASTING

I. LOAD FORECAST METHODOLOGY

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. We also note that, while this Appendix documents our load and energy demand forecasting process, we have taken additional steps with respect to the treatment of energy efficiency (EE) forecasting in this Resource Plan, to model it as a supply-side resource. Where relevant, we include explanations of these steps in order 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 F2: Strategist 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 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 using actual historical loss factors and are held constant over the forecast period. We develop the peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. We provide a detailed discussion of the forecast methodology later in this Appendix.

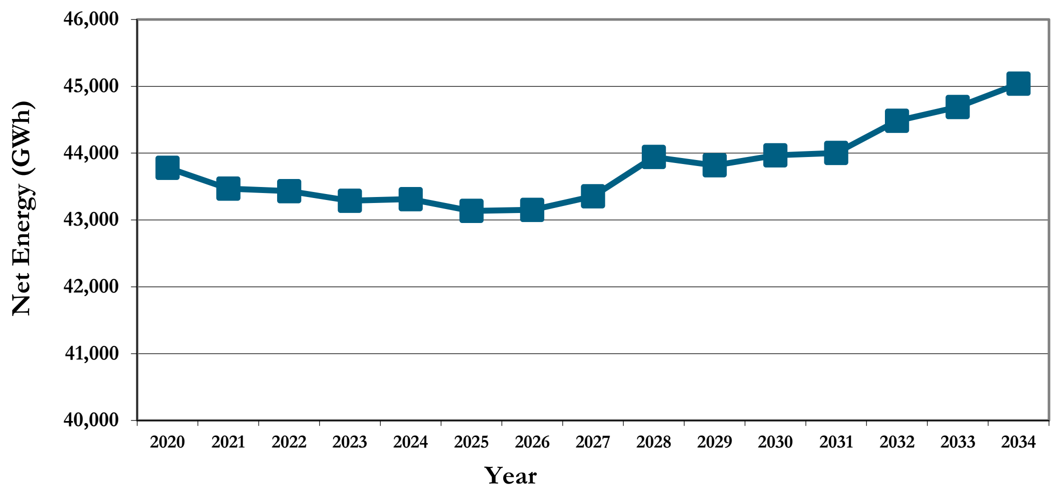
The forecasts are based on projections of economic activity for our various service areas provided by IHS Global Insight, Inc. (Global Insight). Global Insight projects continued growth in key economic indicators. For example, for the Minneapolis-St. Paul metropolitan area, households are expected to increase at an average annual rate of 0.8 percent during the 2020-2034 planning period. Real personal income is expected to increase 0.8 percent per year on average, and employment is expected to gain an average of 0.2 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 Methodology

The base energy forecast increases at an average annual growth rate of 0.2 percent over the 2020 – 2034 planning period, net of the 1.5 percent energy savings level approved in the Company's last Resource Plan, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements are expected to increase at an annual average of 90 gigawatt-hours (GWh), starting with 43,781 GWh in 2020 to 45,038 GWh in 2034. See Figure 1 below.

Figure 1: NSP System Total Median Net Energy (GWh)
(Includes 1.5 Percent EE Adjustment)



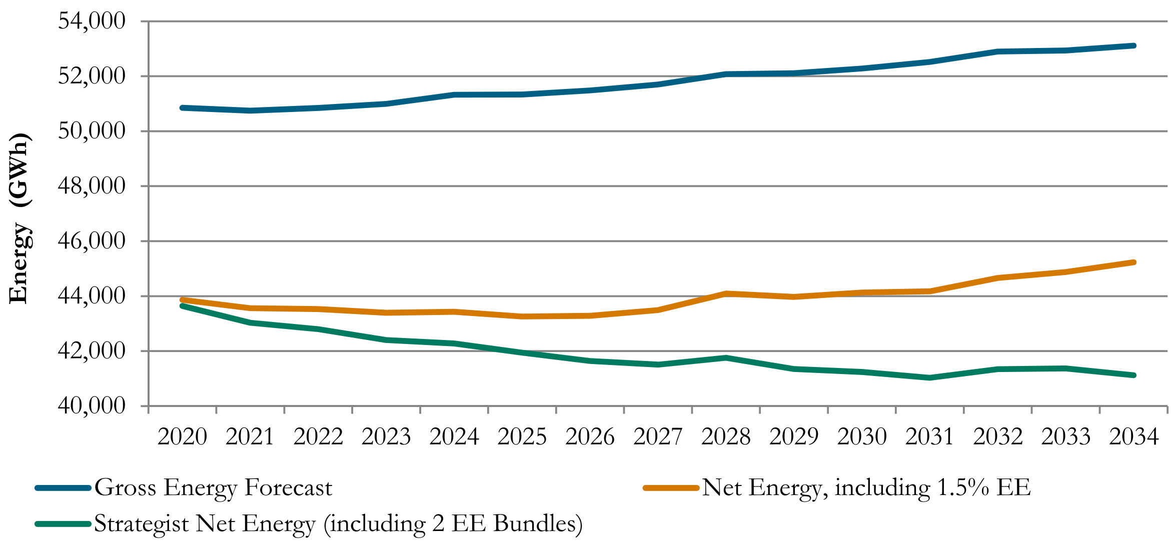
The projected 0.2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements decreased at an average annual rate of *negative* 0.3 percent from 2014 to 2017.

2. Modifications for Use in Strategist

As noted in Chapter 3: Minimum System Needs, we undertook additional steps to allow EE to be modeled 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 1.5 percent 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 Strategist model along with other supply-side resources used to model EE as a supply-side resource in Strategist. We show these adjustments in Figure 2 below.

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



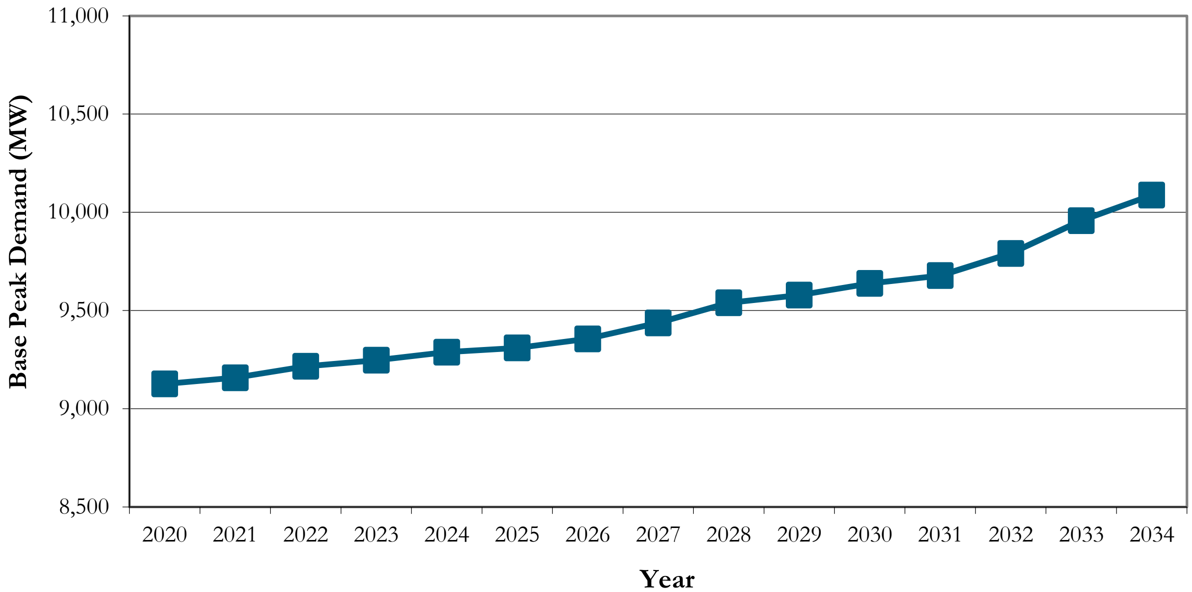
We discuss the EE Bundle modeling further in Appendix F2: Strategist Modeling and Appendix F6: Resource Options.

B. System Peak Demand Forecast

1. *Base Forecast Methodology*

During the 2020 – 2034 planning period, the median base peak increases at an average annual growth rate of 0.7 percent. As demonstrated in Figure 3 below, annual peak demand increases at an average of 69 MW each year, starting with 9,126 MW in 2020 to 10,087 MW in 2034.

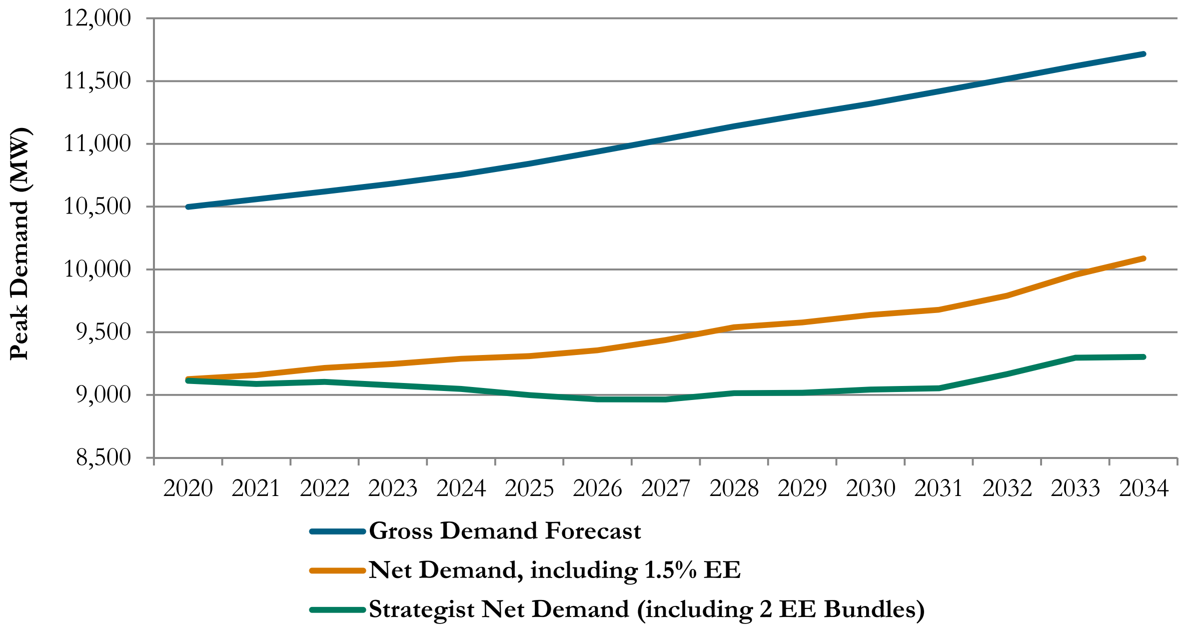
Figure 3: NSP System Median Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



2. *Modifications for Use in Strategist*

For modeling demand levels in Strategist, we took the same approach as noted in reference to the energy forecasts. Again here, for Strategist modeling purposes, we start with the base forecast and remove 1.5 percent EE adjustment in order to reflect gross load. This process enables us to model the system considering EE as a supply-side resource.

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



The balance 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 1 above and the System Base Peak Demand Forecast presented in Part B.1 and Figure 3.

C. Key Demand and Energy Forecast Variables

Below we discuss some of the key variables that are included in the 2019 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 0.6 percent, with the addition of 10,246 residential customers on average per year from 2020 through 2034.

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.

D. 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 and Small Commercial and Industrial sectors for all jurisdictions, the Large Commercial and Industrial sector for Minnesota, 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 customer classes, Large Commercial and Industrial, Public Street and Highway Lighting, and Public Authority in all states but Minnesota, and Interdepartmental, we use trend analysis and customer specific data. 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 using actual historical loss factors and are held constant over the forecast period.

We have developed a regression model to relate Xcel Energy's historical uninterrupted monthly peak demand to energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast. (*Note*: Section II of this Appendix contains a comprehensive summary of the regression modeling process utilized to develop the energy and demand forecasts.)

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the Midcontinent Independent System Operator (MISO) system peak demand. The coincident demand forecast is developed using a regression model that determines the relationship between the NSP System demand coincident with the MISO peak demand and the NSP System peak demand (not coincident with the MISO peak demand). MISO only requires an annual coincident demand forecast for the next planning year. The current resource plan forecast is for the NSP System demand coincident to the MISO annual peak demand during the 2019-20 planning year (June 2019 – May 2020).

E. Forecast Adjustments

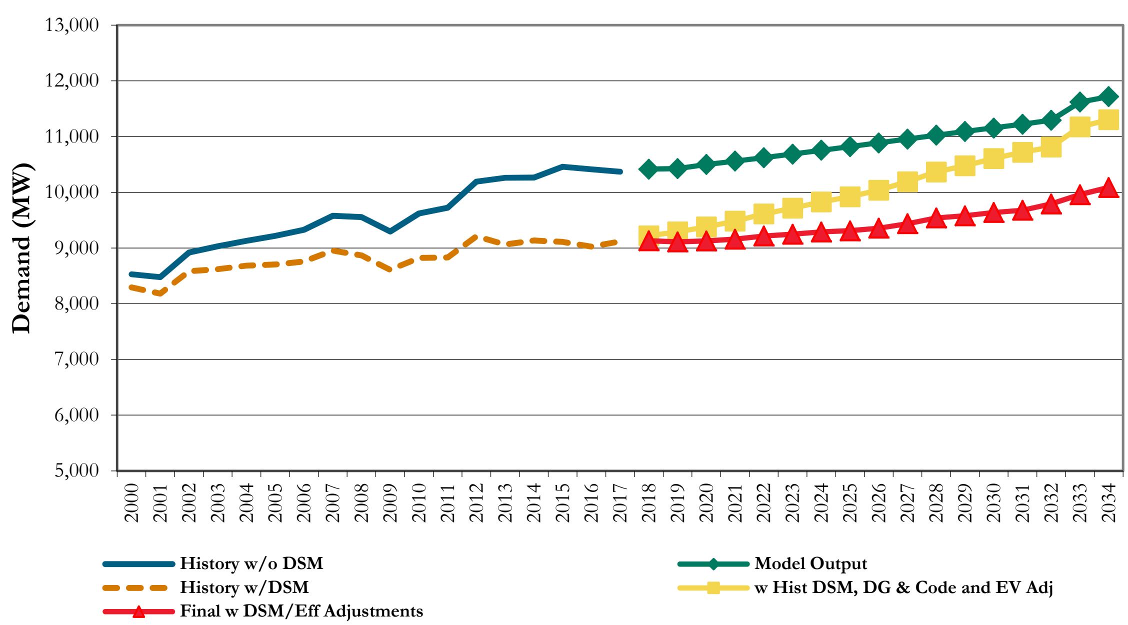
Our demand and energy forecasts are developed using a number of key forecast variables as described in this Appendix. One important adjustment to the forecasts is to take into account our conservation programs.

The EE methodology implemented for the State of Minnesota uses the same method for projecting the impacts of EE and its load management effects on the sales forecast as was used in our 2015 Resource Plan filing. There are three distinct steps to this process:

- 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.
- Also adjust the forecast to account for codes and standards changes resulting in decreased sales that are in addition to Company-sponsored EE.

These EE adjustments are based on the Company's current Triennial Plan goals, which were based on the savings level approved in the resource planning process. The Commission approved an average annual energy savings level of 444 GWh for all planning years in our 2015 Resource Plan in Docket No. E002/RP-15-21.[1] Figure 5 below graphically illustrates the EE adjustment.

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



For the State of South Dakota, the impacts from all conservation program

[1] *See* Order, Ordering Point No. 11 (January 11, 2017).

installations prior to 2018 are assumed embedded in the historical demand and energy data at a rate equal to the annual program installations from 2013 through 2017. To accurately predict future supply needs, the energy and demand forecasts must be reduced by an estimate of the incremental future conservation savings. For the base forecast, we adjust the demand and energy forecast by assuming all future annual conservation achievement equal to achievement of our 2018 goal as approved in the 2016 South Dakota DSM Status Report and 2018 DSM Plan filing (Docket No. EL17-019).

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature, 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 develop net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

F. 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:

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand,
- Increases or reductions in usage due to new customers in our service territory, or planned expansions or reductions of load by existing customers, and increasing use of plug-in electric vehicle charging, which we discuss in Part II.D below.

G. Forecast Variability

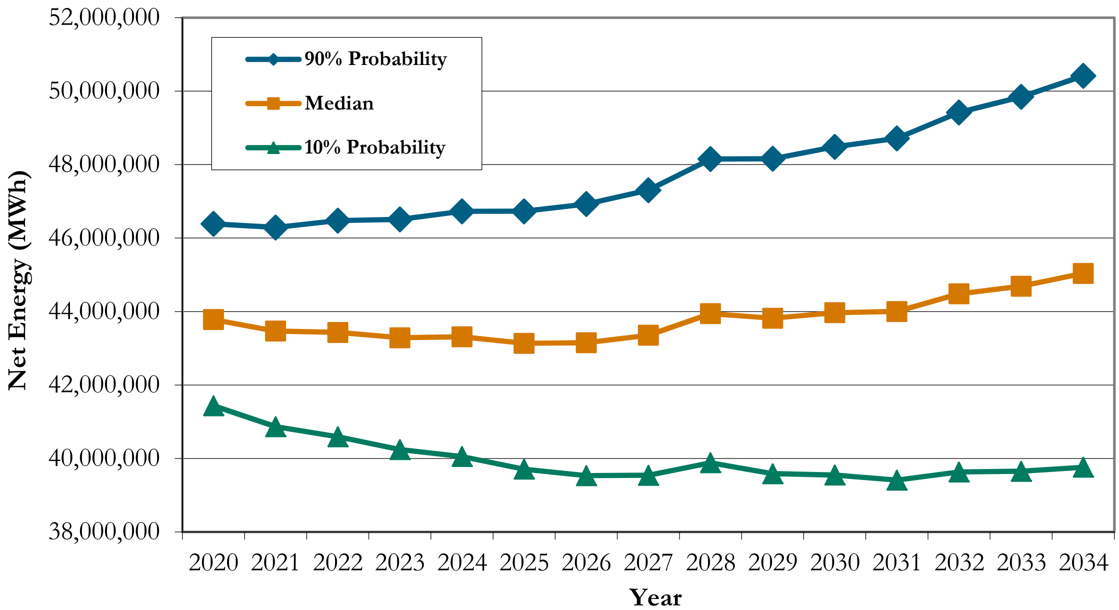
As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than Global Insight has predicted, electric consumption 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 loads in the middle of the planning period due to increased mining activities in Northern Wisconsin. However, at this time there is still uncertainty around this potential increase and, therefore, we have not made an adjustment to the forecast.

Given that there is uncertainty in any long-term forecast, we supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. These probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and a simulation of energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand. We provide a more detailed description of the probability distribution methodology in Section II, and discuss summary results below.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 50,416,762 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 39,760,413 MWh. See Figure 6 below.

Figure 6: NSP System Total Net Energy (MWh)
(Includes 1.5 Percent EE Adjustment)



Figures 7 and 8 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand. [2]

[2] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Figure 7: NSP System Total Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

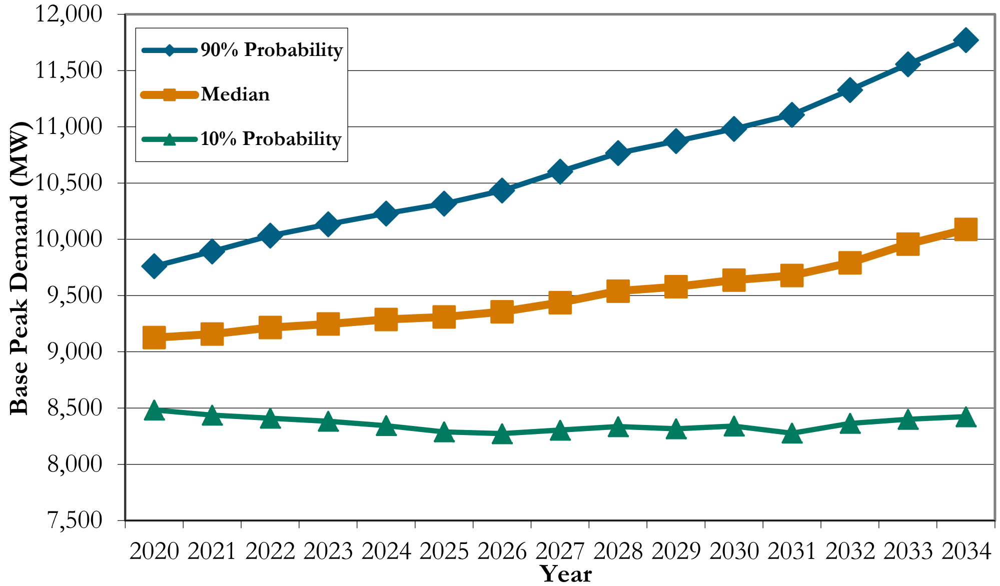
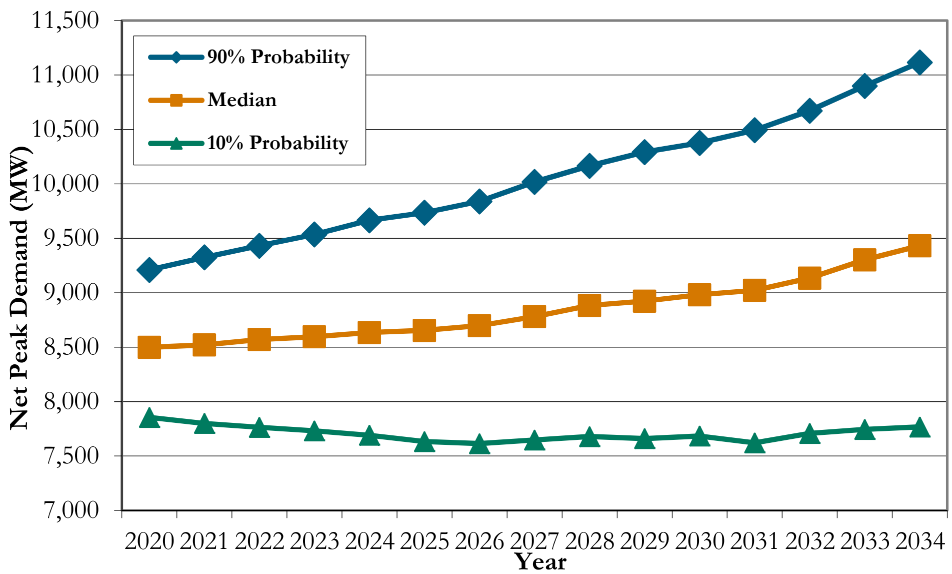


Figure 8: NSP System Total Net Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



Tables 1, 2, and 3 below provide the data underlying Figures 6, 7, and 8, respectively.

Table 1: Annual Net Energy (MWh)
(Including 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	46,387,135	43,780,715	41,434,501
2021	46,289,330	43,467,677	40,864,878
2022	46,475,233	43,430,233	40,590,345
2023	46,508,251	43,287,395	40,240,549
2024	46,727,937	43,311,190	40,052,004
2025	46,728,197	43,135,149	39,706,759
2026	46,927,693	43,150,544	39,530,565
2027	47,302,668	43,354,456	39,539,672
2028	48,151,679	43,942,185	39,881,494
2029	48,158,669	43,817,294	39,583,487
2030	48,484,779	43,967,558	39,546,151
2031	48,714,578	44,001,712	39,410,068
2032	49,421,682	44,482,912	39,632,078
2033	49,845,815	44,689,679	39,649,954
2034	50,416,762	45,038,288	39,760,413
Average Annual Growth 2020 - 2034	**0.6%**	**0.2%**	**-0.3%**

Table 2: Annual Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,761	9,126	8,483
2021	9,892	9,158	8,437
2022	10,032	9,216	8,409
2023	10,134	9,247	8,383
2024	10,229	9,288	8,344
2025	10,317	9,309	8,288
2026	10,433	9,356	8,272
2027	10,602	9,437	8,303
2028	10,766	9,539	8,334
2029	10,873	9,578	8,316
2030	10,982	9,638	8,340
2031	11,107	9,678	8,277
2032	11,327	9,791	8,364
2033	11,556	9,958	8,400
2034	11,771	10,087	8,423
Average Annual Growth 2020 - 2034	**1.4%**	**0.7%**	**-0.1%**

Table 3: Annual Net Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,210	8,498	7,855
2021	9,325	8,520	7,800
2022	9,432	8,571	7,764
2023	9,535	8,596	7,731
2024	9,666	8,635	7,691
2025	9,736	8,654	7,633
2026	9,839	8,698	7,614
2027	10,018	8,781	7,647
2028	10,166	8,883	7,679
2029	10,292	8,922	7,660
2030	10,376	8,982	7,684
2031	10,493	9,022	7,621
2032	10,671	9,135	7,708
2033	10,900	9,302	7,745
2034	11,115	9,432	7,767
Average Annual Growth 2020 - 2034	**1.3%**	**0.7%**	**-0.2%**

H. Forecast Vintage Comparison

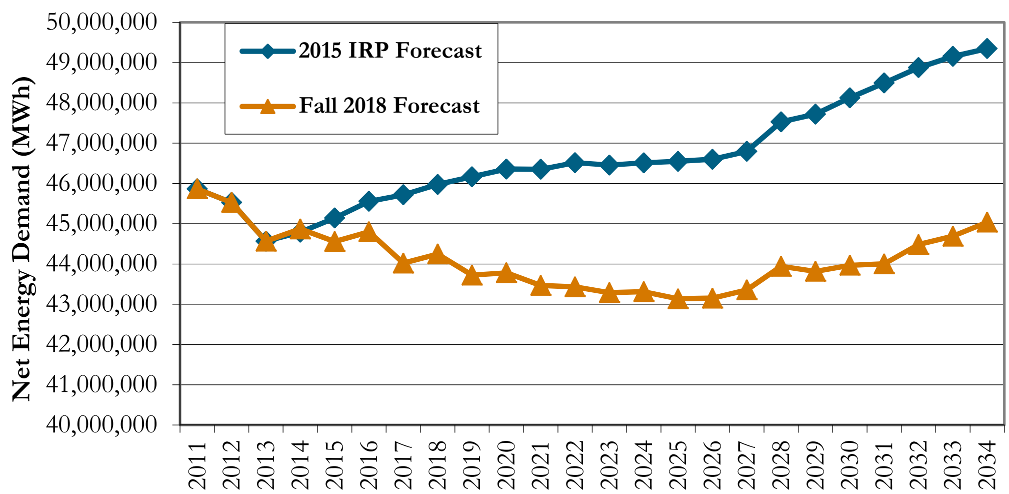
As described above, projections of energy and demand are fundamental to identifying the need for resources to meet expected customer needs. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with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

1. Forecast Vintage and Comparison

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 2015 Resource Plan.

Figure 9 below indicates that the Fall 2018 energy forecast is lower than the Fall 2014 forecast provided in our 2015 Resource Plan due to lower and declining actual sales in 2015, 2016, and 2017. In particular, 2015-2017 weather normalized actual sales were lower for the NSPM residential sector and the NSPM small and large commercial and industrial sectors. In the residential sector, while the actual number of customers was slightly higher than estimated in the Fall 2014 forecast, the larger driver of the weaker-than-expected sales was lower use per customer. The NSPM small commercial and industrial sector also experienced lower-than expected use per customer. The NSPM large commercial and industrial sector was projected to grow in the Fall 2014 forecast, but actual sales declined due to customers installing combined heat and power plants and loss of other load to locations outside Xcel's service territory.

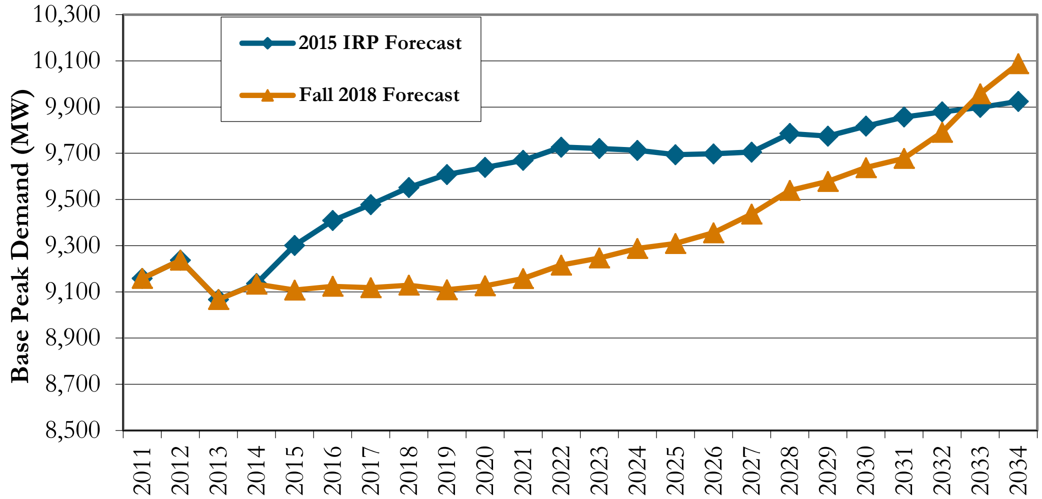
Figure 9: Net Energy Requirements (MWh) – Comparison of Current and Previous Energy Forecast
Median (50th Percentile) Forecast



In addition, the projected rate of growth of key economic indicators is lower now than when the Fall 2014 forecast was produced. For example, the average annual growth rate during the planning period for Minnesota real personal income is 1.8 percent, compared to a projected 3.6 percent in the Fall 2014 forecast. As another example, the average annual growth rate during the planning period for Minneapolis-St. Paul total employment is 0.4 percent, compared to the projected 1.1 percent in the Fall 2014 forecast.

Figure 10 below shows a comparison of the base peak demand forecast to the Fall 2014 forecast. Similar to the energy forecast, the current demand forecast is lower than the Fall 2014 forecast underlying the 2015 Resource Plan for most of the planning period. While actual sales from 2011 to 2017 have trended downward, the NSP system peak demand has remained fairly flat, but well below the Fall 2014 forecast. The current forecast calls for peak demand to increase and surpass the Fall 2014 forecast as energy gains turn positive in the outer years of the planning period.

Figure 10: Base Peak Demand (MW) – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast



II. OVERALL METHODOLOGICAL FRAMEWORK

In this Section, we outline the technical details regarding our forecast, consistent with the requirements of Minn. R. 7610.0320.

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, a Minnesota corporation (NSPM); Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented." The NSPM and NSPW Systems operate as an integrated NSP System. The forecast is referred to as the 2018v2.1 Forecast (August 2018).

A. Specific Analytical Techniques

1. *Econometric Analysis*

Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:

a) Residential without Space Heating;
b) Residential with Space Heating;

c) Small Commercial and Industrial;
d) Large Commercial and Industrial (Minnesota);
e) Public Street and Highway Lighting (Minnesota);
f) Other Sales to Public Authorities (Minnesota).

Xcel Energy also uses econometric analysis to develop the total system MW peak demand forecast.

2. Trend Analysis

Trend analysis is used for the "Other" sectors, which include Public Street and Highway Lighting (all states except Minnesota), Other Sales to Public Authorities (Michigan, North Dakota and Wisconsin), Interdepartmental sales (Michigan, Minnesota and Wisconsin), and Large Commercial and Industrial (Michigan, North Dakota, South Dakota, and Wisconsin).

3. Loss Factor Methodology

Loss factors by jurisdiction are used to convert the sales forecasts into system energy requirements (at the generator).

4. Judgment

Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process. However, judgment is inherent to the development of any forecast. 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 are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts.

A system loss factor for each jurisdiction, developed based on average historical losses, is applied to the jurisdictional sales forecast to calculate total losses. The sum of the jurisdictional MWh sales and losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast MW peak demand for the NSP System.

B. Models Used

1. Residential Econometric Models

Sales to the residential sectors represent 29.7 percent of total NSP System electric retail sales in 2018. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Regression models using historical data are developed for each residential sector. A variety of independent variables is used in the models, including:

- Number of customers;
- Real Personal Income for respective jurisdiction;
- Employment for the respective jurisdiction;
- Gross State Product for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;
- Number of monthly billing days.

2. Small Commercial and Industrial Econometric Models

The small commercial and industrial sector represents 43.7 percent of NSP System electric retail sales in 2018. The models are regressions using historical data. The models include a combination of variables, including the following:

- Number of small commercial and industrial customers;
- Gross State or Metro Product for respective jurisdiction;
- Employment for respective jurisdiction;
- Real Personal Income for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;

3. Large Commercial and Industrial Econometric Models

Sales to the large commercial and industrial sector represent 26.0 percent of NSP System electric retail sales in 2018. The models are regressions using historical data and a combination of variables, including the following:

- Industrial Production for respective jurisdiction;
- Number of monthly billing days;
- Indicator variables such as CI reclassification.

4. Others

Sales to the "Others" sector represent 0.6 percent of NSP System electric retail sales in 2018. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used and very little growth is forecast. Exceptions to this are the Minnesota Street Lighting and Other Public Authority classes. Minnesota Street Lighting sales are based on population in the Minneapolis-St. Paul MSA. Minnesota Other Public Authority sales are based on the Minnesota Other Public Authority customer forecast.

5. Peak Demand Model

An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:

- Weather normalized native energy requirements
- Peak producing weather by month
- Binary variables

C. Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses 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.

D. Data Definitions

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Table 4: Jurisdiction Abbreviations

Mi or MI	State of Michigan
M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin

Table 5: Monthly MWh Sales Series

SLSReswo(Juris)	Residential without space heating for given jurisdiction
SLSResSH(Juris)	Residential with space heating for given jurisdiction
SLSSmCI(Juris)	Small commercial and industrial for given jurisdiction
SLSLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 6: Monthly Customer Series

CustReswo(Juris)	Residential without space heating for given jurisdiction
CustResSH(Juris)	Residential with space heating for given jurisdiction
CustSmCI(Juris)	Small commercial and industrial for given jurisdiction
CustLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 7: Monthly Economic and Demographic Series

HH_(Juris)	Number of Households in given jurisdiction
NR_(Juris)	Total Population in given jurisdiction
GMP_(MSA)	Gross Metro Product for given metropolitan statistical area
GSP_(State)	Gross State Product for given state
EE_(Juris)	Total Employment in given jurisdiction
IPMFG_(Juris)	Industrial Production Index - manufacturing in given jurisdiction
CYP_(Juris)	Real Personal Income in given jurisdiction
(Juris)TotRes_RAP	Real Average Price for electric sales to residential customers

Table 8: Monthly Data Variables used in Demand Model

THI12(Month)Cust	Temperature Humidity Index @12:00 noon on the peak day multiplied by total retail customers
THI15(Month)Cust	Temperature Humidity Index @3:00 PM on the peak day multiplied by total retail customers.
HDD(Season)	Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter - Wtr, shoulder month - sh)
WNActEnergy_LpYrAdj_12MoSum	12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

Table 9: Monthly Weather Variables used in Sales Models

H65_bill (Juris)(Month)	HDD base 65 for given jurisdiction and month
T65_bill(Juris)(Month)	THI DD base 65 for given jurisdiction and month

Table 10: Other Monthly Variables

BillDaysCellnet21	Billing Month Days

Table 11: Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December

E. 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. 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.

F. Energy Efficiency Programs

The regression model results for the residential classes and commercial and industrial classes are reduced to account for the expected impacts of energy efficiency programs.

The EE methodology implemented for the State of Minnesota utilizes a transparent method to project the impacts of energy efficiency (including the energy savings impacts from our current demand response programs) in sales forecasts. There are three distinct steps to this process:

- 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.

The first step involves collecting data involving any measure that would cause an impact on the time period utilized in the sales forecast. In this model, we use the time period from 2003 to 2017, and therefore the historical EE would include any measure that results in decreased sales in any (or all) years from 2003 through 2017.

Since the vast majority of EE measures have a lifetime greater than one year (exceptions include but are not limited to behavioral energy savings programs), the impact on sales will include the year that a measure is installed as well as any years that follow until the measure has reached the end of its useful life. For example, a residential lighting measure that was installed in 2008 and has a life of six years will result in a sales reduction from 2008 to 2013 (six full calendar years). Though a measure may be installed in June of 2008 and, thus, would persist until May of 2013, the Company believes that the simplifying case in which all measures are installed for the entire calendar year is sufficient.

Due to the wide variation of measures available to customers, the Company sums the savings for each year by EE program to optimize the level of detail and depth of history included in the model. As a result of limitations in the quality of data prior to 1996, the Company has taken the conservative approach and omitted the impacts of achievements before 1996. While this may seem inconsequential, some programs have a 20-year lifetime, and EE from 1998 could therefore affect the 2017 usage. Achievement data are from the approved Conservation Improvement Program (CIP) Status Reports filed annually for each year since 1996.

Once the total impact of EE in effect is calculated for each year, a hypothetical sales data set is created. This series consists of the observed sales from 2003 through May 2017 plus the effective EE calculated for all EE measures installed in that year as well is achieved savings from programs in prior years that are still within the useful measure life.

The hypothetical sales data is used to generate a sales forecast that has entirely excluded the impacts of company-sponsored EE. It is important to note that customer-initiated EE or EE due to codes and standards (naturally-occurring EE) is not calculated as part of the CIP.

Once the sales forecast based on hypothetical sales has been generated, the Company subtracts the projected future EE from the total to determine the EE-adjusted sales. In addition, codes and standards changes resulting in decreased sales not documented within CIP may have separate adjustment factors applied in addition to the company-sponsored EE. The source for company-sponsored EE adjustments will be based on the CIP Plan in effect at the time of the forecast.

Exogenous adjustments were made to the Minnesota sales model output for future years to account for codes and standards changes for lighting in the Residential and Business segments. These adjustments are in addition to the adjustments made for future EE program achievement. The sales model implicitly accounts for some portion of changes in customer use, due to conservation and other influences, by basing projections of future consumption on past customer class energy consumption patterns. However, when technologies driving code and standard changes are adopted at an accelerated pace but can no longer be incentivized through EE programs, the sales forecast is not able to adequately adapt to future changes due to the difference between past and projected customer use, and the future changes are not accounted for in the exogenous adjustments made for EE program achievement.

As a result of recent changes in business and residential lighting practices, two new additional adjustments have been added to the sales forecast. The first is for residential customers only, and takes into account the new standard efficiency for general service lamps (also known as EISA standards). For the adjustment to the sales forecast, this only calculates the difference between a standard incandescent and an EISA-compliant halogen bulb, since additional efficiency will still be captured through EE programs. The second adjustment projects business class sales reductions resulting from accelerated technological improvements in the business lighting sector due to improvements in solid state lighting (LED).

A monthly forecast of the impact of new EE programs is developed by Xcel Energy's DSM Regulatory Strategy and Planning Department, and is used to reduce the class level sales forecasts that result from the regression modeling process. Impacts from all program installations through 2017 are assumed to be imbedded in the historical data, so only new program installations are included in the EE adjustment.

The Company's demand response programs result in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

G. Behind-the-Meter Distributed Solar Generation

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature 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, similar to how historical company-sponsored EE programs savings are added back to the historical sale and peak demand modeling data. The forecast output, based on the hypothetical sales and peak demand data with behind-the-meter solar generation added back to the historical sales and peak demand data, is then 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.

H. Forecast 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 of these changes is the reduction of sales and demand related to the scheduled installation of customer-owned Combined Heat and Power generating facilities in 2017 and 2018.

I. Overview of Probability Distributions

Xcel Energy uses a straightforward extension of the peak demand econometric model to assess risk around the expected value of the peak demand by conducting a Monte Carlo simulation on the main drivers of the peak model (weather and native energy requirements). For the Monte Carlo energy probability distribution model, the main drivers are weather, Minnesota Households (HH_MN), and Minnesota Real Gross State Product (CGSP_MN).

The Monte Carlo stochastic simulation of peak demand (MW) or energy (MWh) involves taking 10,000 random draws from the weather probability distributions as well as 10,000 draws from the 12-month sum of energy probability distribution (or HH_MN and CGSP_MN probability distributions), which, in turn, produces 10,000 forecasts of peak demand (or energy), and thus generates a probability distribution around the mean peak demand (or mean energy).

For example, if the econometric model forecasts that the mean peak demand for 2025 is 9,309 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90 percent probability that the 2025 peak demand will be less than 10,317 MW, or alternatively, a 10 percent chance that the peak will be less than 8,288 MW.

In summary, the Monte Carlo stochastic simulation method adequately captures the effect of extreme weather on monthly peak demand and monthly energy usage, while preserving the expected value or mean forecast of peak demand and energy.

J. Data Adjustments and Assumptions

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

Economic Adjustments. All Consumer Price Index data is deflated to 1982=1 and related economic series are deflated to 2009 constant dollars.

K. 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 1998-2017. 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 a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

L. MISO Coincident Peak Demand Forecast

Once we complete the NSP System Peak Demand Forecast, we develop a forecast for the NSP System Peak Demand coincident with the MISO system peak. MISO has published the date and time of the MISO system peak for each of the four summer months (June – September) of 2005 – 2017. Company records were queried to determine the NSP System uninterrupted peak at the time of each of the MISO monthly peak days.

We then develop a forecast of the NSP System peak demand coincident with the MISO peak using a regression model based on the NSP System peaks coincident with

MISO, the NSP System peaks not coincident with MISO, and the weather variable representing the temperature-humidity index at 3:00 PM on the MISO coincident peak day for each summer month. MISO only requires an annual coincident peak forecast for the next planning year. The current forecast is for the NSP System peak coincident to the MISO annual peak during the 2019-20 planning year (June 2019 – May 2020).

M. 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.

III. DISTRIBUTED ENERGY RESOURCES FORECAST

A. Distributed Solar

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. In addition, we offer a net-metering option for customers installing incentivized small scale solar. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.[3] We note that the methodology used to forecast distributed solar for this Resource Plan is consistent with what we used in our November 2018 Integrated Distribution Plan, filed in Docket No. E999/CI-18-251.

1. Reference Case Assumptions

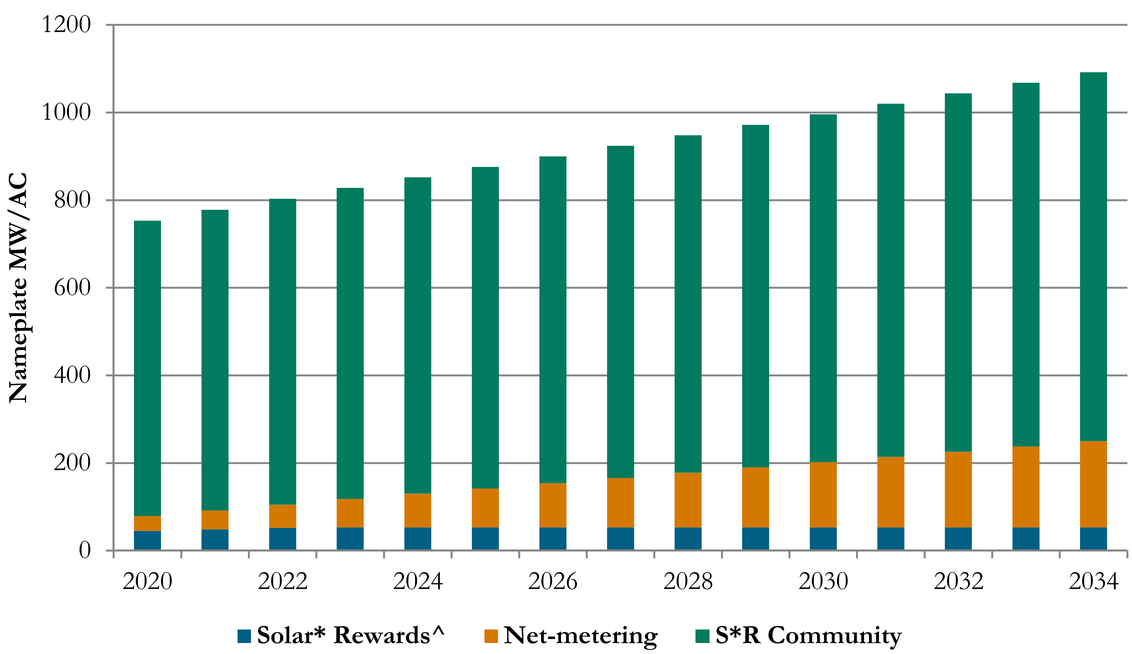
In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in

[3] We note that we provide information specific to just Solar*Rewards Community as Appendix N8.

this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 673 MW through 2019 in this filing. For our Reference Case assumptions through the Resource Plan planning period, we assume Solar*Rewards Community adjusts to approximately 12 MW per year after 2021 to account for significant early adoption of CSGs and reduction in tax benefits. The graph below reflects the Reference Case forecast of distributed solar PV forecast.

Figure 11: Reference Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



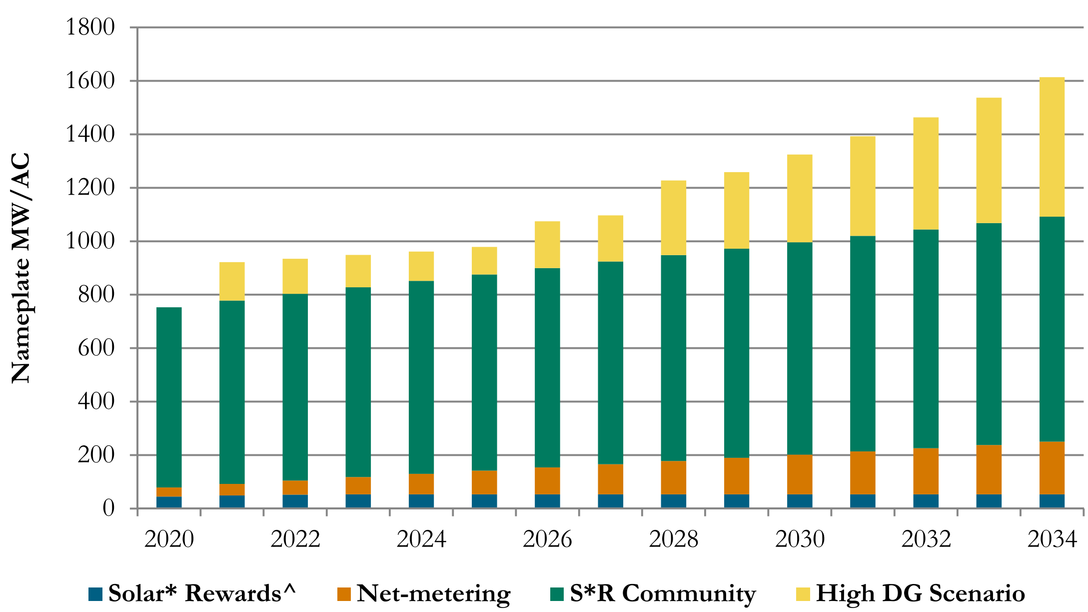
^Includes Made in Minnesota

2. Reference vs High Forecasts

The Reference and High scenarios hold the levels of Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category. For example, we are estimating that total solar PV in 2034 is approximately 1,100 MW – of which, approximately 850 MW is net metering and CSG.

For the High scenario, we used a Payback adoption model with lower installation costs. We also applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Reference scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,600 MW for total installed distributed solar by 2034. The graph below reflects the high forecast of distributed solar PV forecast.

Figure 12: High Forecast Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



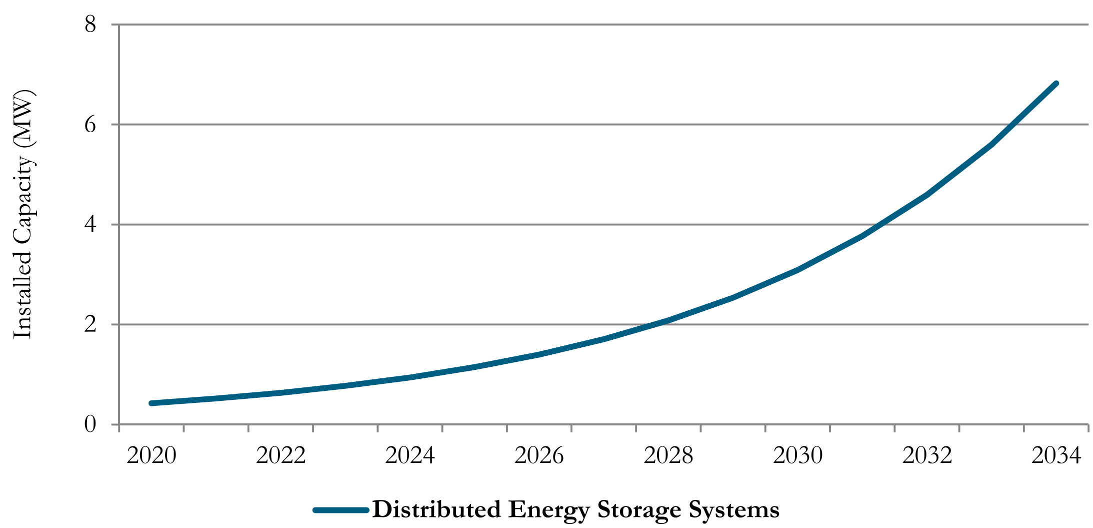
B. Distributed Wind

We presently have a small number of distributed wind projects on our system, with a total of 59 projects that comprise 14 MW. 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. Distributed Storage

Navigant Research's Global DER Overview, 2Q 2019, projects a growth rate of 21.9 percent for Distributed Energy Storage Systems (DESS). From 2017 through April 2019, we received approximately 50 interconnection applications for energy storage on our distribution system. Of these 50 applications, 32 are complete and in operation, comprising approximately 350 kW. Figure 13 below extrapolates the current installations at the Navigant projected rate of growth.

Figure 13: NSP System Distributed Energy Storage Systems Forecast



The impact of DESS is, currently, not incorporated into demand forecasting or as a specific supply side resource. We discuss the utility-scale storage as it applies to the modeling underlying this Resource Plan in Appendix F6: Resource Options.

D. Electric Vehicles

Our customers are procuring EVs in greater numbers than ever before. In our Upper Midwest service area, the total number of EVs is currently approximately 9,500.[4] Nationally, annual sales of EVs increased by 81 percent from 2017 to

[4] IHS Markit, 2019. The IHS Markit data is provided at the zip code level for zip codes within the Company's service territory. Utility jurisdictions do not exactly follow zip code boundaries, so there may be some margin

2018.[5] Forecasts suggest that we may see increased adoption as EVs are poised to grow into a more mainstream new vehicle option, with over 40 models of EVs available in the United States today. The nascent nature of this market however, makes the possibility of significantly more or less adoption a large variable, and thus difficult to forecast.

The approach we took in this Resource Plan to forecast EVs allows for consideration of a wide range of potential futures, and represents an advancement and change from our approach in our November 1, 2018 Integrated Distribution Plan (IDP). The IDP used a forecast based on national level adoption that had informed early- to mid-2018 filings in other dockets.[6] At that time we noted our intent to improve, benchmark, and validate our forecasting models and assumptions, which is underway. We also noted that we were doing work around electrification to support our upcoming Resource Plan.

That said, for the purposes of this Resource Plan, we made an exogenous adjustment for a base level of light duty electric vehicle adoption in both our energy and demand forecasts. We then worked with E3 to develop a high "electrification" load forecast sensitivity, which includes a broader range of EV adoption – as well as other electrification impacts.[7] This creates a wide band of possible outcomes to inform our modeling. We believe that by limiting the modeling of a highly dynamic external factor to a Base and High view, we are better able to examine the base needs of the system, while also considering the long-term impacts of potential high electrification across Minnesota's economy.

We illustrate the Base and High Electrification forecasts that informed this Resource Plan in Figure 14 below. We additionally show the Base EV forecast for this Resource Plan to give perspective on the magnitude of electrification the High Electrification sensitivity affords the modeling in this Plan.

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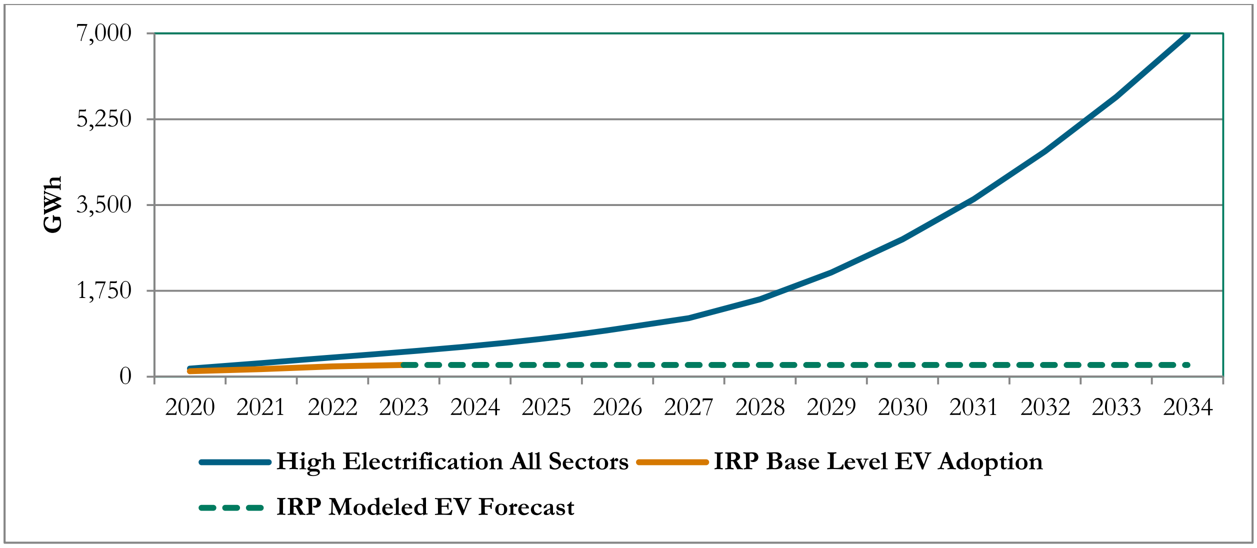
of error in this value.

[5] InsideEVs PEV Scorecard, https://insideevs.com/monthly-plug-in-sales-scorecard/.

[6] June 1, 2018 filing in Docket No. E002/M-15-111 and a January 11, 2018 response to Minnesota Commission Staff Information Request No. 8 in our hosting capacity proceeding in Docket No. E002/M-17-777.

[7] We provide a full discussion of the E3 high electrification sensitivity as Appendix F4.

Figure 14: NSP System Base Level Compared to High Electrification Sensitivity – 2020-2034



We discuss our development of the Base Forecast below. We discuss the details of the High Electrification Sensitivity in Appendix F4: High Electrification Sensitivity and note that it was developed as part of E3's PATHWAYS study, provided as Appendix P3: Minnesota PATHWAYS Report June 2019 (E3).

1. *Base EV Adoption*

The Base EV forecast projects adoption of light duty vehicles in the first five-years of the planning period and then holds constant from year six through the remainder of the planning period. This Base level of light duty EV adoption is used in all modeling scenarios, and is consistent with the likely forecast from the IDP. The rate and level of EV adoption impacts the energy forecast, and customer charging behavior assumptions impact the demand forecast, which we discuss in turn below.

a. EV Adoption Levels

Our Base EV forecast is based on an internally-developed methodology that incorporates both economic payback and Bass diffusion (technology adoption) model.[8] Key variables informing our adoption estimates for the base energy forecast

[8] The Bass Model or Bass Diffusion Model was developed by Frank Bass. It consists of a simple differential equation that describes the process of how new products get adopted in a population. The model presents a rationale of how current adopters and potential adopters of a new product interact. The basic premise of the model is that adopters can be classified as innovators or as imitators and the speed and timing of adoption

include:

- Electricity Prices
- Vehicle Battery Prices
- Gasoline Prices
- Car ownership
- Car usage
- Efficiency

In addition to EV adoption, customer charging behavior is an important consideration to factor into our load forecasts. Because we are reflecting adoption of only light duty EVs in our base forecast, our primary considerations are the share of charging done at homes, and penetration of managed charging stations. Our source for this was the DOE EV Project Data Set.

Forecasting is very sensitive to various assumptions, especially for new technologies like EVs that are in early stages of adoption. Forecasts are also sensitive to several externalities like policy changes (such as incentives), technology changes (such as battery improvements and autonomous vehicles), geopolitical issues (such as trade and tariff issues), availability of raw materials (such as shortages of lithium or cobalt), etc. Additionally, many of the inputs change frequently and could produce significant swings in the model outputs.

2. *High Electrification Sensitivity*

We worked with E3 to develop a High Electrification load forecast sensitivity, derived from the E3 statewide decarbonization analysis using PATHWAYS,[9] which we ran for each Resource Plan modeling scenario. The objective of this sensitivity was to create a "bookend," examining the possible impacts on load growth and peak demand growth on our Upper Midwest NSP System service area, under a scenario with electrification sufficiently aggressive to achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[10]

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depends on their degree of innovativeness and the degree of imitation among adopters. The Bass model has been widely used in forecasting, especially new products' sales forecasting and technology forecasting.

[9] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3.

[10] Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives.

Without suggesting this much electrification will or should occur, this sensitivity asks: If there were very aggressive electrification of transportation, buildings, and other end uses, what are the potential impacts on energy consumption and peak demand during the planning period?

We summarize the E3 High Electrification sensitivity in Appendix F4, and provide as Attachment A to that Appendix, E3's detailed discussion of their methodology.

3. Summary

We believe planning for electrification must contemplate a variety of future state scenarios, but also that EVs and electrification broadly are not a primary driver that will influence resource decisions in this Resource Plan. We are continuing to refine our EV forecasting methods as we learn more about the EV industry and adoption trends nationally. We expect to provide updated EV-specific forecast scenarios in our November 2019 IDP.

APPENDIX F2 – STRATEGIST MODELING ASSUMPTIONS & INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

D. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 GPDIPD of

113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC 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 issued June 11, 2018). All prices escalate at general inflation.
The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO_2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The "Load Forecast with 1.5% EE" shown in Table 4 below is the starting point for the Strategist load inputs. In all modeling scenarios, the "1.5% EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2047. In its place, three EE Bundles (discussed below) are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as "Forecast Without 1.5% EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Strategist Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table 5 and Table 6, and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth			
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). The Bundles are included in Strategist as Proview Alternatives and any number of these Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast and, the same as for EE, are dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). These Bundles are included in Strategist as Proview Alternatives and any number of the Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 8: Demand Response Forecast

	Demand (MW) Adjusted For Reserve Margin				Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	848	0	0	0	0	0	0
2019	924	0	0	0	0	0	0
2020	940	270	107	89	14,380	7,659	11,311
2021	955	290	112	97	15,724	8,150	12,587
2022	970	312	116	106	17,212	8,676	14,016
2023	989	322	120	110	18,124	9,137	14,758
2024	1007	339	132	101	19,512	10,277	13,829
2025	1023	380	145	92	22,305	11,459	12,858
2026	1038	392	151	93	23,475	12,207	13,326
2027	1053	406	159	95	24,786	13,080	13,845
2028	1066	421	168	97	26,245	14,086	14,418
2029	1054	438	178	99	27,859	15,231	15,047
2030	1043	456	189	101	29,637	16,522	15,734
2031	1032	476	201	104	31,551	17,926	16,467
2032	1021	497	214	106	33,612	19,451	17,251
2033	1010	519	227	109	35,832	21,109	18,088
2034	1000	542	242	112	38,224	22,911	18,984
2035	990	567	257	116	40,802	24,870	19,943
2036	981	594	274	119	43,582	26,999	20,971
2037	972	630	293	125	46,580	29,313	22,072
2038	963	660	312	129	49,814	31,829	23,253
2039	954	692	332	133	53,305	34,564	24,522
2040	945	726	353	138	57,073	37,537	25,884
2041	937	726	353	138	58,215	38,288	26,402
2042	929	726	353	138	59,379	39,054	26,930
2043	921	726	353	138	60,566	39,835	27,468
2044	913	726	353	138	61,778	40,632	28,018
2045	906	726	353	138	63,013	41,444	28,578
2046	898	726	353	138	64,274	42,273	29,150
2047	891	726	353	138	65,559	43,118	29,733
2048	884	726	353	138	66,870	43,981	30,327
2049	876	726	353	138	68,208	44,860	30,934
2050	869	726	353	138	69,572	45,758	31,552
2051	862	726	353	138	70,963	46,673	32,183
2052	854	726	353	138	72,382	47,606	32,827
2053	847	726	353	138	73,830	48,558	33,484
2054	839	726	353	138	75,307	49,530	34,153
2055	832	726	353	138	76,813	50,520	34,836
2056	825	726	353	138	78,349	51,531	35,533
2057	817	726	353	138	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table 9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting in year 2022.

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge 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 from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

L. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

M. Spinning Reserve Requirement

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. The level of spinning reserve modeled is 137 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

We note additionally that interconnection costs for generic resources are included in the capital costs in Table 14 in Part U of this Appendix, and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	400	140

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

Q. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a twenty five year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs. The Company expects a transition from Solar*Rewards to non-incentivized DG over time due to the end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

R. 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. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. 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 Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

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

PPAs are modeled based upon their tested operating characteristics and contracted 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 renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns are developed through a "Typical Wind Year" process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Utility-scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10, while DG/distributed solar does not.

The Reference Case assumes "no going back" on renewables, meaning that we are committed to pursuing repowering and/or contract extension opportunities for renewable resources that will expire , and renewable resources are replaced "in-kind" when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is approximately 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to approximately 4,500 GWhs by 2028. The Company has already procured the levels of wind contemplated in the previous Resource Plan, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast. Below is a list of typical operating and cost inputs for each generic resource.

<u>Thermal</u>

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

<u>Renewable</u>

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$15,000	$19,058	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$17.96	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$14.46	$16.19	$5.96	$6.27	$8.14
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

Table 16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	88
Equivalent Full Cycles per Year	156
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$10.53

Table 17: Levelized Capacity Costs by In-Service Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.14	$6.27	$5.96	$16.19	$14.46			
2019	$8.31	$6.40	$6.08	$16.51	$14.75			
2020	$8.47	$6.53	$6.20	$16.84	$15.04			
2021	$8.64	$6.66	$6.33	$17.18	$15.35			
2022	$8.81	$6.79	$6.46	$17.52	$15.65			
2023	$8.99	$6.93	$6.58	$17.88	$15.97	$10.53	$8.03	$13.71
2024	$9.17	$7.07	$6.72	$18.23	$16.28	$9.48	$6.99	$12.51
2025	$9.35	$7.21	$6.85	$18.60	$16.61	$8.91	$6.35	$11.92
2026	$9.54	$7.35	$6.99	$18.97	$16.94	$8.53	$5.90	$11.41
2027	$9.73	$7.50	$7.13	$19.35	$17.28	$8.24	$5.53	$11.04
2028	$9.93	$7.65	$7.27	$19.74	$17.63	$8.02	$5.20	$10.73
2029	$10.13	$7.80	$7.41	$20.13	$17.98	$7.83	$4.92	$10.49
2030	$10.33	$7.96	$7.56	$20.53	$18.34	$7.68	$4.65	$10.28
2031	$10.53	$8.12	$7.71	$20.94	$18.71	$7.54	$4.51	$10.19
2032	$10.75	$8.28	$7.87	$21.36	$19.08	$7.42	$4.39	$10.13
2033	$10.96	$8.44	$8.03	$21.79	$19.46	$7.31	$4.27	$10.08
2034	$11.18	$8.61	$8.19	$22.23	$19.85	$7.22	$4.16	$10.05
2035	$11.40	$8.79	$8.35	$22.67	$20.25	$7.13	$4.05	$10.02
2036	$11.63	$8.96	$8.52	$23.12	$20.65	$7.05	$3.94	$10.02
2037	$11.86	$9.14	$8.69	$23.59	$21.07	$6.98	$3.83	$10.03
2038	$12.10	$9.32	$8.86	$24.06	$21.49	$6.91	$3.73	$10.05
2039	$12.34	$9.51	$9.04	$24.54	$21.92	$6.85	$3.63	$10.07
2040	$12.59	$9.70	$9.22	$25.03	$22.36	$6.79	$3.53	$10.09
2041	$12.84	$9.89	$9.40	$25.53	$22.80	$6.73	$3.44	$10.11
2042	$13.10	$10.09	$9.59	$26.04	$23.26	$6.68	$3.36	$10.13
2043	$13.36	$10.29	$9.78	$26.56	$23.72	$6.63	$3.28	$10.15
2044	$13.63	$10.50	$9.98	$27.09	$24.20	$6.58	$3.20	$10.17
2045	$13.90	$10.71	$10.18	$27.63	$24.68	$6.54	$3.12	$10.20
2046	$14.18	$10.92	$10.38	$28.19	$25.18	$6.50	$3.10	$10.13
2047	$14.46	$11.14	$10.59	$28.75	$25.68	$6.46	$3.09	$10.07
2048	$14.75	$11.37	$10.80	$29.33	$26.19	$6.42	$3.07	$10.01
2049	$15.05	$11.59	$11.02	$29.91	$26.72	$6.38	$3.06	$9.96
2050	$15.35	$11.82	$11.24	$30.51	$27.25	$6.35	$3.04	$9.91
2051	$15.65	$12.06	$11.46	$31.12	$27.80	$6.31	$3.03	$9.85
2052	$15.97	$12.30	$11.69	$31.74	$28.35	$6.28	$3.01	$9.80
2053	$16.29	$12.55	$11.93	$32.38	$28.92	$6.25	$3.00	$9.76
2054	$16.61	$12.80	$12.16	$33.03	$29.50	$6.22	$2.98	$9.71
2055	$16.94	$13.06	$12.41	$33.69	$30.09	$6.19	$2.97	$9.66
2056	$17.28	$13.32	$12.66	$34.36	$30.69	$6.16	$2.95	$9.62
2057	$17.63	$13.58	$12.91	$35.05	$31.30	$6.13	$2.94	$9.58

Table 18: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 19: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 20: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26

**Distributed Solar costs represent at the meter values before grossing up for losses.*

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 2018 in Table 21 below.

Table 21: 2018 FERC Heat Rates

Unit	Heat Rate
AS King	10,013
Sherco	10,546
Monticello	10,505
Prairie Island	10,487
Black Dog (NG)	7,870
High Bridge	6,863
Riverside	7,172
French Island	23,570
Wilmarth	10,637

The Company's Performance Monitoring department performs routine heat rate testing and conducts heat balances of its generating units. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted. 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 22 below shows a summary of NSP System heat rate testing from 2015-2018.

Table 22: Heat Rate Tests – 2015-2018

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Sherco U1	Coal Boiler	Heat Rate	2015
Bayfront U4	Combustion Turbine	Calculated Adjustment for Fuel Change	2016
King U1	Coal Boiler	Heat Rate	2016
Sherco U2	Coal Boiler	Heat Rate	2015, 2016
Black Dog U5/U2	Combined Cycle	Heat Rate	2015, 2017
High Bridge CC	Combined Cycle	Heat Rate	2017, 2018
Sherco U3	Coal Boiler	Heat Rate	2017
Black Dog U6	Combustion Turbine	Heat Rate	2018
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2017,2018

As part of its heat rate testing and reporting protocol, the Performance Monitoring 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 heat rate testing 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 Strategist 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 allow for limited thermal variances.

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 will impact all plants that withdraw water for cooling purposes. The new 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.

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

While specific conditions, such as high water discharge temperatures, are not directly modeled in Strategist, the model reflects the impact of reducing plant output due to high water temperatures. Modeling in Strategist includes two methods to account for impacts due to changes in plant operations: each resource is modeled using a unit specific median unforced 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 high water temperatures is reflected through corrections to both obligation and resource adjustments.

ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following table shows load and resources using Installed Capacity Rating (ICAP) for the planning period, in compliance with the Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings.[1]

Table 23: Load and Resources Tables, 2020-2034 Planning Period

ICAP Rating - Load and Resources 2020-2034 Planning Period

Determination of Need	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Forecast Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO System Coincident (ICAP)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO Planning Reserve	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Obligation	10,670	10,641	10,660	10,627	10,595	10,537	10,498	10,495	10,556	10,558	10,589	10,599	10,733	10,885	10,892
Existing and Approved Resources	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Load Management, Existing	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management, Potential Study	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,471	2,471	2,471	2,471	1,773	1,773	1,773	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
Nuclear	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,053	1,053	1,053	527
Natural Gas/Oil	3,511	3,511	3,511	3,511	3,347	3,032	2,784	2,260	2,139	2,139	2,139	2,139	1,858	1,858	1,858
MEC	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Sherco CC	0	0	0	0	0	0	0	786	786	786	786	786	786	786	786
Biomass/RDF	107	107	107	84	84	60	60	60	19	19	19	19	19	19	19
Hydro	887	1,009	1,002	1,002	1,002	152	152	152	152	152	152	152	145	142	142
Wind	3,954	4,200	4,200	4,054	4,054	4,034	4,012	3,913	3,848	3,739	3,735	3,439	3,372	2,984	2,620
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Solar*Rewards Community	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Grid Scale Solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Existing Resources	15,117	15,530	15,569	15,438	14,620	13,477	13,243	12,732	12,543	12,448	12,460	11,536	11,200	10,837	9,968
Existing and Approved Net Resource (Need)/Surplus	4,446	4,889	4,909	4,811	4,025	2,941	2,745	2,237	1,987	1,890	1,871	937	466	-48	-924
Reference Plan Resource Additions/Retirements	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Natural Gas/Oil	0	0	0	0	0	0	0	0	0	0	0	0	220	570	920
Wind	0	0	0	126	171	242	307	379	389	496	512	568	598	1,122	2,702
Solar	0	0	0	0	0	251	251	752	1,002	1,252	1,253	1,753	2,004	2,004	2,004
Reference Plan Resource Adjustments	0	0	0	126	172	492	558	1,131	1,391	1,749	1,765	2,321	2,822	3,696	5,627
Reference Plan Net Resource (Need)/Surplus	4,446	4,889	4,909	4,937	4,197	3,433	3,303	3,367	3,379	3,639	3,636	3,258	3,288	3,647	4,702

[1] *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).

APPENDIX F3 - SCENARIO SENSITIVITY ANALYSIS: PVRR & PVSC SUMMARY

		A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
	PVSC	**PVRR**	**Low Gas/Coal/ Mkts**	**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**
1- REFERENCE	$45,657	$37,679	$45,216	$46,360	$46,328	$49,952	$44,760	$46,813	$40,949	$39,008	$42,541	$52,890	$37,276	$45,260	$49,797	$45,359
2- EARLY KING	$45,450	$37,495	$44,909	$46,347	$46,258	$49,795	$44,703	$46,499	$40,570	$38,811	$42,319	$52,001	$37,064	$44,896	$49,787	$45,276
3- EARLY SH3	$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
4- EARLY COAL	$45,449	$37,632	$44,882	$46,394	$46,274	$49,777	$44,758	$46,475	$40,435	$38,934	$42,324	$51,128	$37,202	$44,859	$49,968	$45,311
5- EARLY MONTI	$45,824	$37,782	$45,347	$46,570	$46,498	$50,093	$44,907	$47,034	$41,021	$39,111	$42,673	$52,931	$37,356	$45,325	$49,953	$45,470
6- EARLY PI	$46,345	$38,281	$45,847	$47,119	$46,892	$50,741	$45,222	$47,704	$41,558	$39,584	$43,177	$53,636	$37,847	$45,739	$50,392	$45,715
7- EARLY All NUCLEAR	$46,491	$38,292	$45,956	$47,306	$47,000	$50,782	$45,329	$47,873	$41,586	$39,620	$43,267	$53,725	$37,857	$45,840	$50,503	$45,768
8- EARLY BASELOAD	$46,251	$38,144	$45,561	$47,366	$46,985	$50,646	$45,341	$47,462	$41,006	$39,488	$43,002	$51,915	$37,710	$45,306	$50,747	$45,734
9- EARLY COAL; EXTEND MONTI	$45,173	$37,476	$44,705	$45,966	$46,084	$49,419	$44,628	$46,065	$40,250	$38,757	$42,098	$50,829	$37,050	$44,646	$49,701	$45,327
10- EARLY KING; EXTEND MONTI	$45,124	$37,286	$44,684	$45,877	$46,010	$49,444	$44,552	$46,054	$40,322	$38,590	$42,044	$51,601	$36,860	$44,628	$49,601	$45,258
11- EARLY COAL; EXTEND PI	$44,788	$37,134	$44,395	$45,449	$45,711	$49,020	$44,327	$45,595	$39,885	$38,406	$41,731	$50,394	$36,705	$44,239	$49,551	$45,100
12- EARLY COAL; EXTEND All NUCLEAR	$44,655	$37,240	$44,460	$45,018	$45,589	$48,794	$44,194	$45,462	$39,977	$38,455	$41,696	$50,435	$36,813	$44,356	$49,324	$45,177
13- EXTEND MONTI	$45,268	$37,316	$44,833	$45,978	$46,130	$49,577	$44,690	$46,181	$40,516	$38,635	$42,156	$52,315	$36,884	$44,720	$49,665	$45,394
14- EXTEND PI	$44,830	$36,906	$44,440	$45,455	$45,757	$49,158	$44,379	$45,618	$40,080	$38,219	$41,729	$51,800	$36,471	$44,266	$49,382	$45,157
15- EXTEND All NUCLEAR	$44,749	$37,065	$44,541	$45,116	$45,678	$48,852	$44,316	$45,508	$40,209	$38,333	$41,744	$51,812	$36,636	$44,394	$49,255	$45,281
REFERENCE ADJ (ADD DR)	$45,974	$38,055	$45,534	$46,677	$46,679	$50,276	$45,077	$47,131	$41,267	$39,327	$42,859	$53,204	$37,595	$45,579	$50,121	$45,711
PREFERRED PLAN	$45,513	$37,851	$45,046	$46,307	$46,416	$49,757	$44,969	$46,405	$40,591	$39,099	$42,439	$51,168	$37,392	$44,990	$50,040	$45,660
ND PLAN	$45,892	$37,598	$44,869	$45,901	$46,833	$50,123	$45,231	$46,904	$40,415	$38,892	$42,208	$51,021	$37,208	$44,817	$49,443	$45,356

		A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
DELTAS	**PVSC**	**PVRR**	**Low Gas/Coal/ Mkts**	**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**
1- REFERENCE	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
2- EARLY KING	($207)	($184)	($307)	($12)	($71)	($156)	($56)	($315)	($379)	($197)	($222)	($889)	($213)	($365)	($10)	($83)
3- EARLY SH3	($93)	($17)	($198)	$60	$45	($12)	$69	($220)	($306)	($33)	($124)	($1,022)	($41)	($267)	$137	$37
4- EARLY COAL	($208)	($47)	($334)	$35	($54)	($174)	($1)	($339)	($513)	($74)	($217)	($1,762)	($75)	($401)	$170	($48)
5- EARLY MONTI	$167	$103	$131	$210	$170	$142	$147	$220	$72	$103	$131	$42	$80	$65	$156	$111
6- EARLY PI	$689	$602	$631	$759	$564	$789	$462	$891	$609	$576	$636	$746	$571	$479	$595	$356
7- EARLY All NUCLEAR	$834	$613	$740	$947	$672	$831	$569	$1,060	$637	$612	$726	$835	$581	$580	$706	$409
8- EARLY BASELOAD	$594	$465	$345	$1,006	$656	$695	$582	$649	$57	$480	$460	($975)	$433	$46	$950	$375
9- EARLY COAL; EXTEND MONTI	($484)	($204)	($510)	($394)	($245)	($533)	($131)	($748)	($699)	($251)	($443)	($2,060)	($226)	($614)	($96)	($32)
10- EARLY KING; EXTEND MONTI	($532)	($393)	($532)	($482)	($318)	($508)	($207)	($759)	($626)	($418)	($498)	($1,288)	($416)	($632)	($197)	($101)
11- EARLY COAL; EXTEND PI	($868)	($545)	($821)	($911)	($617)	($931)	($433)	($1,218)	($1,064)	($602)	($811)	($2,496)	($571)	($1,022)	($247)	($259)
12- EARLY COAL; EXTEND All NUCLEAR	($1,001)	($439)	($756)	($1,342)	($740)	($1,158)	($566)	($1,352)	($972)	($553)	($846)	($2,455)	($463)	($904)	($473)	($182)
13- EXTEND MONTI	($388)	($363)	($383)	($381)	($198)	($375)	($70)	($632)	($433)	($373)	($386)	($575)	($393)	($540)	($133)	$34
14- EXTEND PI	($827)	($773)	($776)	($905)	($571)	($794)	($381)	($1,195)	($868)	($789)	($813)	($1,090)	($805)	($995)	($416)	($202)
15- EXTEND All NUCLEAR	($908)	($614)	($675)	($1,244)	($650)	($1,099)	($444)	($1,305)	($739)	($675)	($797)	($1,078)	($640)	($867)	($542)	($79)
REFERENCE ADJ (ADD DR)	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
PREFERRED PLAN	($461)	($203)	($488)	($371)	($263)	($519)	($109)	($726)	($675)	($228)	($420)	($2,037)	($203)	($588)	($81)	($51)
ND PLAN	($83)	($456)	($665)	($777)	$154	($153)	$154	($227)	($852)	($435)	($652)	($2,184)	($388)	($761)	($678)	($355)

APPENDIX F4 – HIGH ELECTRIFICATION SCENARIO DESCRIPTION

We worked with Energy and Environmental Economics (E3) to develop a High Electrification load forecast sensitivity, derived from the E3 statewide decarbonization analysis using PATHWAYS.[1] The objective of this sensitivity was to create a "bookend," examining the possible impacts on load growth and peak demand growth on our Upper Midwest NSP System service area, under a scenario with electrification sufficiently aggressive to achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[2] The Company does not suggest this amount of electrification is likely to occur, absent additional policy measures. We note that an 80 percent economy-wide reduction could theoretically be achieved with less electrification and more of other measures.

Without suggesting this much electrification will or should occur, the sensitivity asks: if there were very aggressive electrification of transportation, buildings, and other end uses, what are the potential impacts on energy consumption and peak demand during the planning period?

I. METHODS

E3 details its methodology in Attachment A to this Appendix. In summary, E3 began with the High Electrification scenario developed in its Minnesota PATHWAYS analysis.[3] In that analysis, E3 created two scenarios, High Electrification and High Biofuels, both targeting the 80 percent by 2050 economy-wide goal. The High Electrification scenario assumes low-carbon electricity (48 percent zero-carbon generation by 2025, 90 percent by 2050) and a high amount of energy efficiency – including high-efficiency appliances and building shell weatherization. All light, medium, and heavy-duty vehicle sales are electric by 2050; sales of electric heat pump equipment reach 95 percent by 2050, replacing electric, natural gas and LPG alternatives; and 50 percent of liquid fuels used in agriculture are electrified by 2050. As a result, statewide total electricity demand grows 60 percent by 2050, relative to 2015. Load growth is especially pronounced in the latter years (2035-2050).

E3 then developed hourly load shapes for each electrified end use, using simulated

[1] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3.

[2] Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives.

[3] This analysis is summarized in E3 presentations from September 24 and October 23, 2018. *See* https://www.xcelenergy.com/company/rates_and_regulations/resource_plan_overview/midwest_energy_plan and, under Current Status, the 9/24/18 and 10/23/18 Workshop Materials.

demand by year based on a 2009 weather year. Water heating, which becomes dominated by heat pump water heaters, is assumed to be a "managed" load capable of being limited largely to off-peak hours. Passenger EVs are assumed to be mostly (90 percent) managed to avoid peak demand impacts. This is based on the experience of Xcel Energy and other utilities, that most charging happens at home and that it will likely be feasible, with a combination of technological controls and time-sensitive rates, to incentivize EV owners to mostly avoid on-peak charging. Heavier EVs and agricultural electrification are conservatively assumed to be flat across hours, i.e. an unmanaged load.

Electrified space heating, however, has a significant potential impact on total energy and peak demand, and is less amenable to being managed to off-peak hours. E3 assumed an increasing share of space heating is served by electric air-source heat pumps (ASHPs), which face special challenges in cold climates. Because efficiency of ASHPs decreases as outdoor air temperature drops, ASHPs are paired with backup electric resistance and thermal heating in this scenario. Below 0° Fahrenheit, there is a non-linear increase in input energy needs as an increasing share of heat is provided by electric resistance backup. See Attachment A to this Appendix for greater detail.

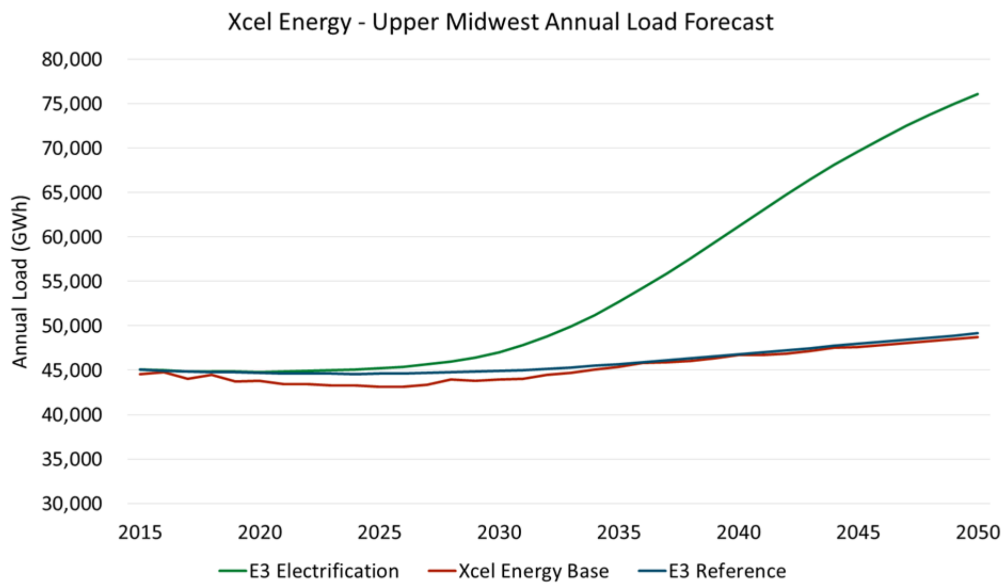
Finally, E3 scaled the Minnesota-wide results to the NSP System, i.e. Xcel Energy's service territory across five Upper Midwest states. Based on historical energy data, in recent years Xcel Energy's retail sales in those five states have been on average 67 percent of total retail sales in Minnesota, so E3's forecast of load and peak demand Minnesota-wide is multiplied by 67 percent to derive load and peak demand for the NSP System under this High Electrification sensitivity. This approach assumes that the scaling of Minnesota loads to the NSP System stays constant over the forecast period. If electrification of transportation, water, and space heating has a different growth rate in our Upper Midwest service territories than in Minnesota as a whole, then both energy and demand impacts could be significantly different for Xcel Energy.

II. RESULTS

Even with aggressive electrification of transportation, water heating and space heating, impacts on incremental energy and peak demand needs are relatively slight during the 2020-2034 Resource Plan planning period – but much more significant by 2050. This is primarily because adoption of EVs and electrified appliances reaches its "hockey stick" phase only near the end of the planning period. Further, even once electric alternatives dominate new sales, the stock of vehicles and appliances takes time to turn over.

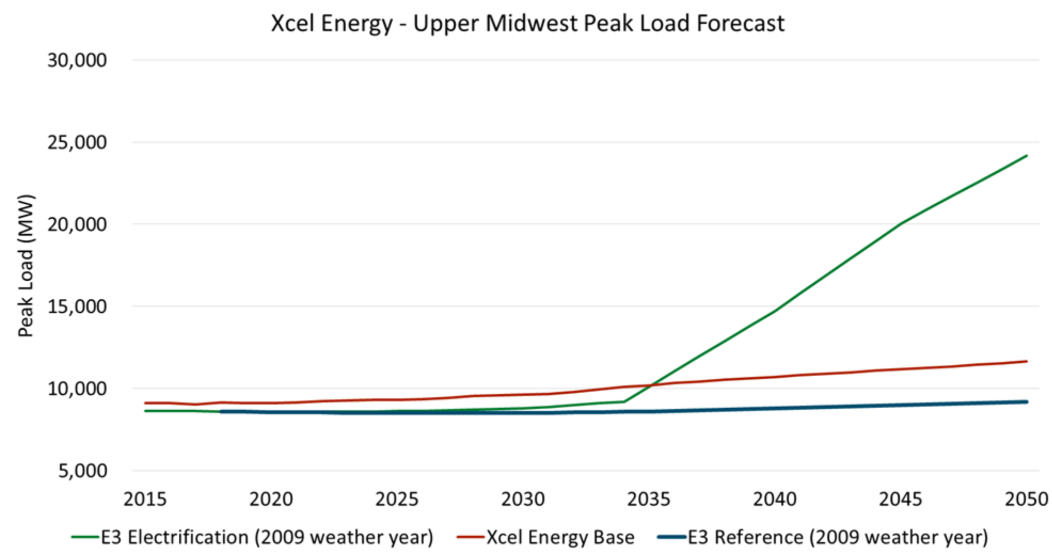
Load Impacts. When compared to E3's reference scenario, the high electrification scenario requires incremental energy on our Upper Midwest system of about 2,000 GWh in 2030 and 5,700 GWh by 2034. Incremental energy requirements increase dramatically thereafter, reaching 14,000 GWh in 2040 and almost 27,000 GWh by 2050. See Figure 1 below.

Figure 1: Incremental Annual Load under a High Electrification Scenario



Peak Demand Impacts. Impacts on peak demand under a high electrification scenario likewise come primarily after the planning period. For example, incremental peak demand requirements due to electrified loads are only 430 MW by 2034, but escalate dramatically thereafter, reaching over 5 GW of incremental peak demand by 2040 and almost 15 GW by 2050. See Figure 2 below.

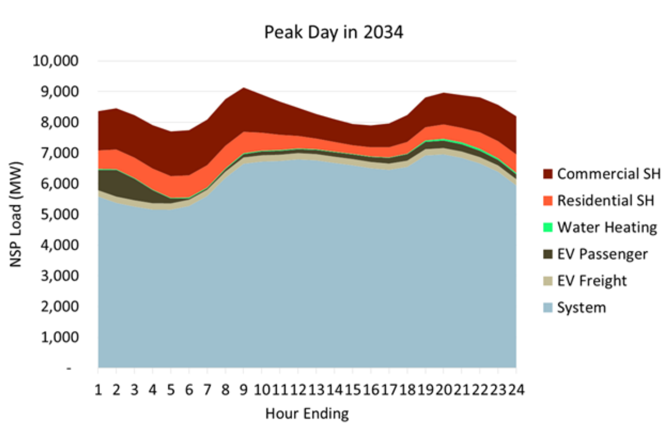
Figure 2: Incremental Peak Demand under a High Electrification Scenario

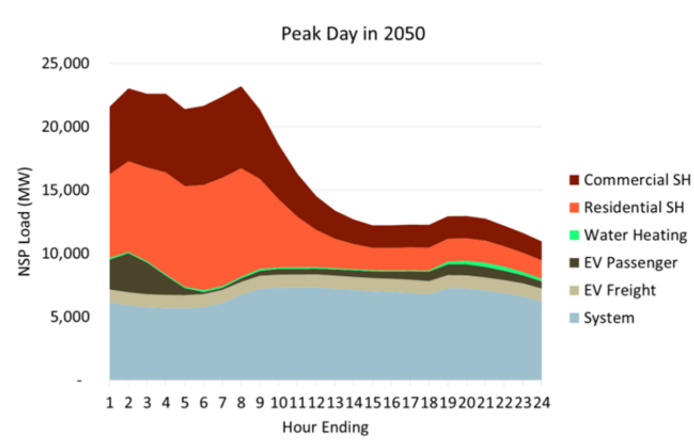


While some electrified loads, such as passenger EVs and water heating, are able to be managed mostly to off-peak hours, space heating has a significant peak demand impact since heating is needed round-the-clock. Figure 3 below shows peak demand in 2034 and 2050, illustrating both that the bulk of peak demand needs are from residential and commercial space heating – and, that space heating imposes incremental peak demand needs in all hours. After about 2034, our Upper Midwest NSP System becomes a winter peaking utility in this scenario.

Figure 3: Electricity Demand on a Peak Day in 2034 (Left) and 2050 (Right) under a High Electrification Sensitivity

Note difference in y-axis scale





III. IMPLICATIONS

Achieving Minnesota's goal of an 80 percent economy-wide GHG reduction will be challenging. Because of the progress the electricity sector has made to-date in reducing emissions, and its expected continued progress by 2050, there is significant potential to reduce emissions from other economic sectors using low-carbon electricity, which could help Minnesota achieve its statutory GHG goals. However, if electricity use by other sectors is to grow significantly, it is all the more important to maintain affordable and reliable electricity – highlighting the need to take advantage of economies of scale in pursuing low- and zero-carbon electricity options.

While most of the High Electrification sensitivity's impacts on load and peak demand come beyond the planning period, it is important to avoid a myopic view in planning the energy system to serve this potential demand beyond 2034. Firm capacity needs would increase dramatically just beyond the end of the planning period in this sensitivity. This strengthens the rationale for the Reliability Requirement – a minimum amount of firm, dispatchable resources to meet customers' energy needs whenever they peak, as discussed in Appendix J2: Reliability Requirement. Incremental peak capacity needs can be mitigated to some degree by putting in place time-sensitive rates and technological controls needed to manage electrified loads (EVs, water heating) to off-peak hours and match these flexible loads to hours of high renewable generation. However, as discussed in conjunction with the Reliability Requirement, renewable generation is not always available. Additionally, not all electrified loads are amenable to shifting off-peak, so it will be important to plan the system with a view beyond 2034.

Finally, a strategic electrification (or "beneficial electrification") approach may be preferable to an "electrify everything" approach. Considering cold climate challenges of some types of electrification, the difficulty of managing some electrified loads to off-peak hours, and the relative efficiency of the natural gas local distribution system in providing heat, it makes sense to focus electrification efforts on those end uses where electrification meets criteria such as:

- Reducing system costs for all utility customers;
- Reducing net CO_2 emissions; and
- Providing for a more efficient utilization of grid resources.[4]

[4] As adopted in Colorado Senate Bill 19-236, and similar to the definition of beneficial electrification proposed by the Regulatory Assistance Project in https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/.

Xcel NSP High Electrification Scenario

June 26, 2019

Prepared for Xcel Energy

By Energy and Environmental Economics, Inc.

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1 Background

This study investigates the potential future of Minnesota's energy economy. We model Minnesota's energy economy on an annual time scale, with key outputs including annual emissions, electric loads, and electric supply changes.

We model two evolutions: the evolution of energy demands and energy supply. To model energy demands we use LEAP, the Long-range Energy Alternatives Planning system. LEAP is an energy accounting framework that provides annual economy-wide energy and emissions results, including a stock roll-over component for major equipment categories (energy uses in buildings and transportation fleet). E3, in partnership with Xcel Energy - Upper Midwest, developed a LEAP model to represent the energy economy of Minnesota (Minnesota PATHWAYS). This model includes developing representation of the Minnesota economy as it exists today, and a series of transformations that reduce economy-wide emissions consistent with achieving the Next Generation Energy Act goal of 80% below 2005 emissions levels by 2050.

We take annual electricity loads from Minnesota PATHWAYS, downscale them to the Xcel Energy - Upper Midwest service territory, and pass them to RESOLVE, E3's electricity capacity expansion and operations model. We use RESOLVE to develop least-cost optimal expansion plans of the electricity grid. Together, the models allow us to track the change in composition of the Minnesota energy economy annually, as well as evaluate how the Xcel Energy - Upper Midwest electric supply could change in a decarbonized future. This document highlights the methods and data surrounding this modeling effort, with a focus on the High Electrification scenario.

The scope of our analysis does not focus on the full scope of greenhouse gas (GHG) emissions, which include agricultural and waste water emissions; we focus on direct energy consumption and energy supply.

Energy forecasting methodology

We begin by tracking the high level economic drivers: population, housing units, square footage, and total vehicle miles traveled (VMT). These data are sourced primarily from various federal and state data sources, including the Census and 2018 AEO. From these economic drivers, we forecast energy demands by using either a stock rollover approach, or a total energy approach.

When infrastructure data is available (such as the number of vehicles) we use a stock rollover approach to model the number of devices and track the improvements in efficiency or change in energy usage as newer, more efficient devices replace retiring devices.

A stock rollover approach allows us to track sales and retirements of devices by technology, track efficiency improvements explicitly, and see the physical lag in the energy system as devices are bought and consumed throughout their lifetimes before being replaced. Note shorter lived technologies, such as lighting and hot water heaters, might roll over multiple times during the study period whereas longer lived technologies, such as power plants and building shells, might roll over only once.

Using a stock rollover approach, the Minnesota PATHWAYS model tracks energy demand associated with existing devices from prior years that have not reached the end of their life. We establish the on-site energy demand associated with these devices by multiplying the number of devices from each vintage with the per-unit energy demand applicable to each vintage.

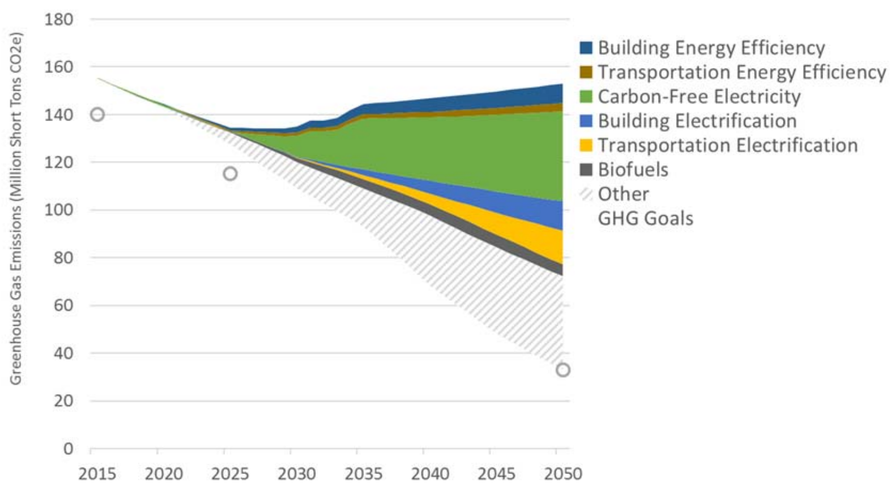
Secondly, we model the number of new devices that are added to each subsector every year. Every year sales of new devices are set to a quantity sufficient to replace retiring devices and meet the demand for new growth (new growth tracks the economic drivers such as housing units or population). Similar to the existing devices, we establish the on-site energy demand associated with new devices by multiplying the number of devices with the appropriate energy usage per device applicable to the new devices' vintage.

When data are limited or of poor quality (such as the industrial sector), we use a total energy approach in which we directly specify the energy demand by fuel, and forecast future energy demands benchmarking to fundamental economic drivers, such as population or AEO energy demand forecasts.

2 Summary of the "High Electrification" scenario:

The High Electrification scenario forecasts a pathway for Minnesota to achieve 80% decarbonization of the energy economy relative to a 2005 base year by 2050. This scenario leans heavily on electrification of end uses wherever practical. An electrification heavy pathway is dependent on carbon-free electricity that is used to displace fossil fuels in buildings and vehicles (Figure 1).

Figure 1. GHG Reductions by Measure: High Electrification Scenario



The high electrification scenario increases load by **60%** in 2050, relative to 2015. Load growth is especially pronounced in the latter years (2035-2050) as load growth from vehicle and space heating electrification exceed energy efficiency gains (Figure 2). For more details on key assumptions see Table 1, below.

Figure 2. Minnesota Load in the High Electrification Scenario

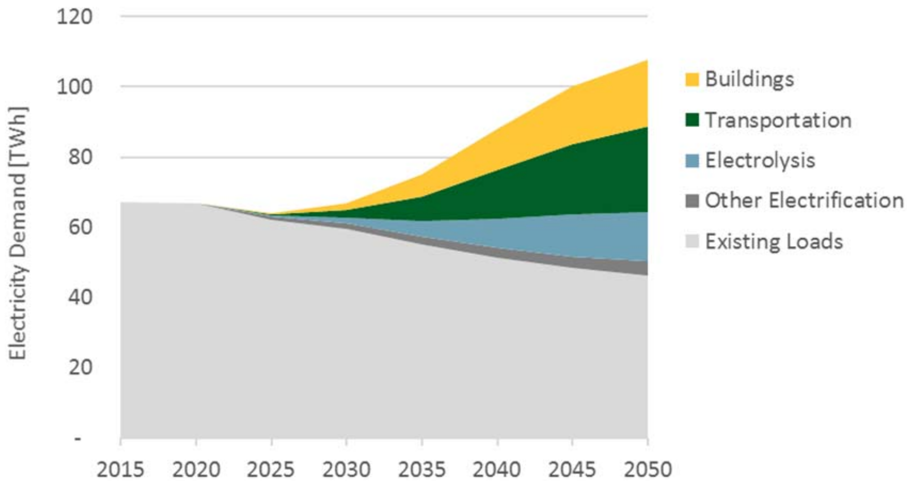


Table 1. Key scenario assumptions

	High Electrification (and low EE)
Electricity generation	
Zero-carbon generation	48% by 2025, 90% by 2050
Nuclear power	Assume nuclear is relicensed or replaced with other carbon-free generation
Buildings	
Energy Efficiency	50% of appliance sales are high-efficiency by 2030 No smart appliances and conservation by 2050 No reduction in demand in nonstock (Residential Other and Commercial Other) demand by 2030, and 30% reduction by 2050
Building Shell and Weatherization	100% adoption of efficient building shell/weatherization measures by 2030
Sales of Electric Heat Pump Equipment	50% by 2030, 95% by 2050, replacing electric, natural gas and LPG
Transportation	
Sales of Zero-Emission Vehicles	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 100% by 2050 HDVs: 40% by 2030, 100% by 2050
Efficiency	Federal CAFÉ standards for LDVs through 2026
Other	50% of Residual Fuel Oil is electrified by 2050
Industry and Other	
Energy Efficiency	No efficiency improvements below baseline
Agriculture Electrification	50% of liquid fuels (Diesel, Gasoline, LPG) are electrified in Agriculture by 2050, at a 50% efficiency improvement due to electrification

3 Electrification load shapes

3.1 Load shapes for water heating and electric vehicles

In developing hourly electric load shapes, this study investigates the electric power system impacts of electrifying a variety of end uses including space heating, water heating, transportation electrification, and others. The next section discusses our space heating load shaping methodology in greater detail. Here we briefly cover the methodology used to create shapes for water heating, transportation electrification, and other electrification.

Water heating: In the High Electrification scenario there is a move towards increased heat pump water heater penetration. E3 used a set of managed heat pump and electric resistance water heating shapes from the Xcel Energy team. The managed resistance water heater shapes are controlled to have no demand from 7am through 6PM. Heat pump water heater shapes are sourced from a broader electricity and decarbonization study commissioned in part by Great River Energy and performed by Brattle in 2016[1]. To capture a representative split of years we use an 80%/20% split of heat pump water heaters / electric resistance water heaters and calculate a blended managed water heating profile. We calculate this profile for a single day that is applied to all the days in a year.

Passenger EV: In the High Electrification scenario there is a move towards increased vehicle electrification, of both passenger and freight. To calculate the load impact of electric passenger EV, E3 used a set of EV load profiles provided by Xcel Energy. These load profiles are sourced from the EV Project, and include both managed and unmanaged charging shapes[2]. For this analysis, we use a blended profile of 90% managed and 10% unmanaged charging. We again calculate this profile for a single day that is applied to all the days in a year.

Freight EV and Agriculture: The final major sources of incremental electrification in the High Electrification scenario are freight vehicles and agriculture. Public data on freight vehicle electric load shapes are sparse. Without accurate, publicly available charging data it is difficult to calculate a representative charging profile for these end uses, so E3 used a flat block across all hours – this indicates that charging demand is consistent across all hours. This is likely not to be accurate, especially if real-time electricity prices fluctuate strongly in future years as these vehicles might exhibit more sophisticated and price responsive charging behavior than the average residential passenger vehicle. Nevertheless, without more data we use a flat charging profile for this study.

In addition to the three categories mentioned above, space heating is the last significant source of electric load growth in the High Electrification scenario. Since space heating has the potential to create operational challenges due to its peaky nature in cold weather, we discuss space heating load shaping in more detail below.

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[1] https://greatriverenergy.com/wp-content/uploads/2015/10/Appendices-H-L.pdf
[2] https://www.energy.gov/sites/prod/files/2014/02/f8/nissan_leaf_driving_charging_2011.pdf

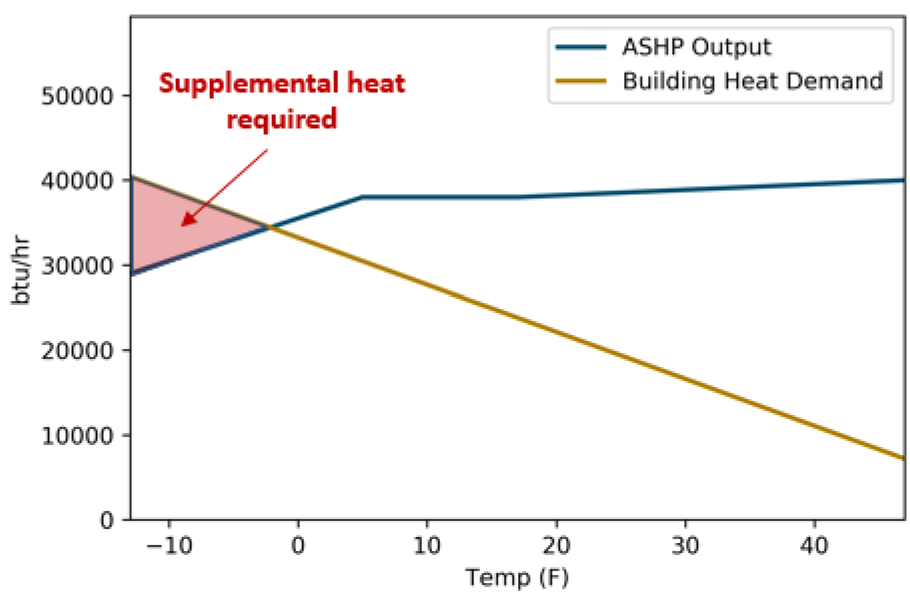
3.2 E3 space heating load shaping methodology

The E3 High Electrification scenario assumes that an increasing share of space-heating loads in Minnesota are served by electric air-source heat pumps (ASHP). ASHPs are relatively rare in Minnesota today, but in the High Electrification scenario adoption of ASHP technologies approaches 90% of state-wide floorspace by 2050. Such a large-scale adoption of ASHPs would add large new, and weather dependent, loads to the state's electricity system.

ASHPs and weather

The efficiency and output capacity of an ASHP decrease as outdoor air temperature drops. When an ASHP can no longer provide enough heat to maintain building comfort, supplemental sources of heat are required (Figure 3**Error! Reference source not found.**). There are two sources of supplemental heat typically used in combination with an ASHP: electric resistance and thermal. For the purposes of the High Electrification scenario we assume that all supplemental heat is served by electric resistance. Where a heat pump can have a coefficient of performance of higher than 2 cold temperatures, the COP of electric resistance heat is 1. The combination of decreasing heat pump efficiency and increasing reliance on electric resistance heat means that ASHPs require non-linear amounts of input power to keep buildings warm in cold weather.

Figure 3: Building Loads and Heat Pump Output

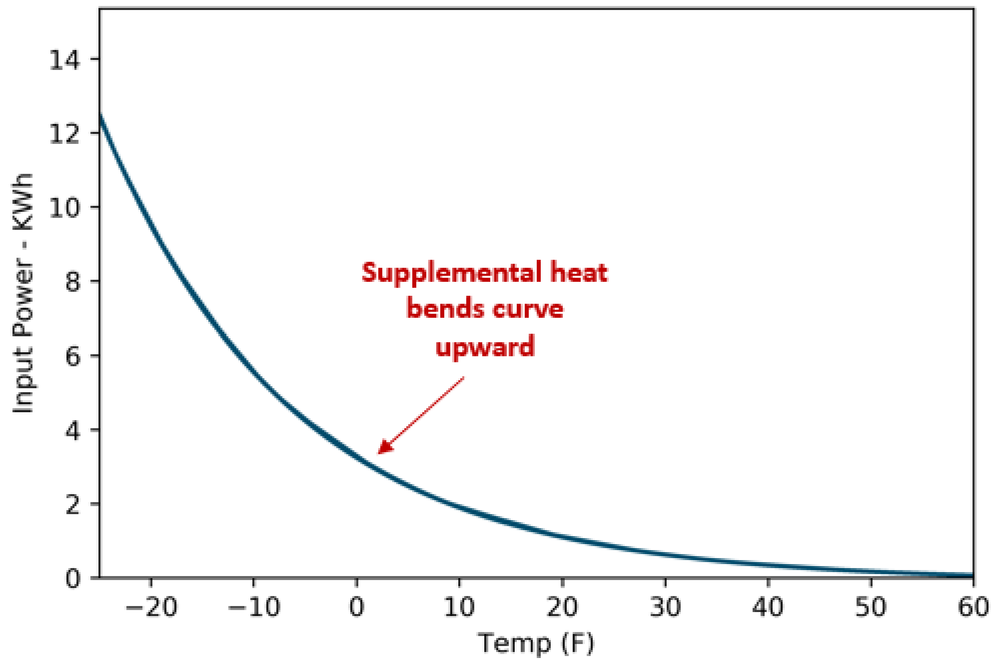


Building simulations and benchmarking

E3 developed relationships between temperature and ASHP loads for both residential and commercial buildings through simulations in the building science software EnergyPlus. E3 used a combination of Federal and local sources (EIA RECS 2015, EIA CBECS 2012, CEE 2018, CEE 2017, Edwards et al 2018) to benchmark the simulations to MN building heat demands.

Figure 4 shows the derived relationship between temperature and a cold climate ASHP load for a typical residential home in Minnesota[3]. The heat pump can cover all of the building's load until 0F, at which point an increasing share of heat is provided by the electric resistance element. By -25F, the ASHP has a COP of 1, the point at which buildings are assumed to be entirely heated by electric resistance.

Figure 4: Residential Heat Pump Load & Temperature



Weather matching

ASHP loads are weather dependent. On a very cold day outdoor air temperatures across Minnesota can vary by a wide margin (Figure 5). For instance, on January 16, 2009 the minimum outdoor air temperature was -5F in Cottonwood County but was -38F during the same hour in Koochinching County. This temperature gradient can lead to very different per-building loads across the state. For instance, a residential building in Cottonwood County with design load of 38 kbtu per hour requires 4 kW of input power to stay warm. That figure for an equivalent building in Koochinching County quadruples to over 16 kW because the heat pump is running entirely in electric resistance back-up mode.

In order to account for the diversity of weather impacts, E3 used a combination of NOAA historical weather data and Census county-level household data. E3 matched NOAA weather stations to their nearest county neighbor in order to develop a geographically explicit per-building load prediction (Figure 5). These shapes were then multiplied by the number of fuel-switching households per county and summed to develop a diversified ASHP shape for Minnesota as a whole. Figure 6 shows the cumulative 2050 loads from ASHP space heaters under a 2009 weather year on both an annual and peak week basis.

[3] The performance of this heat pump is consistent with a top performing 48 kbtu/hr (4-ton) heat pump on the NEEP Cold Climate Heat Pump Product Specification listing.

Figure 5: Minimum Temperatures on January 16, 2009

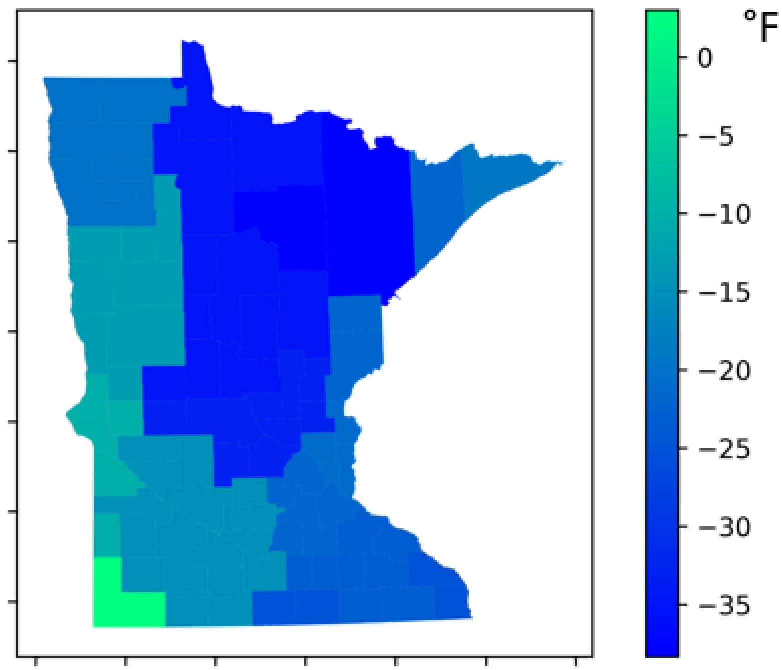
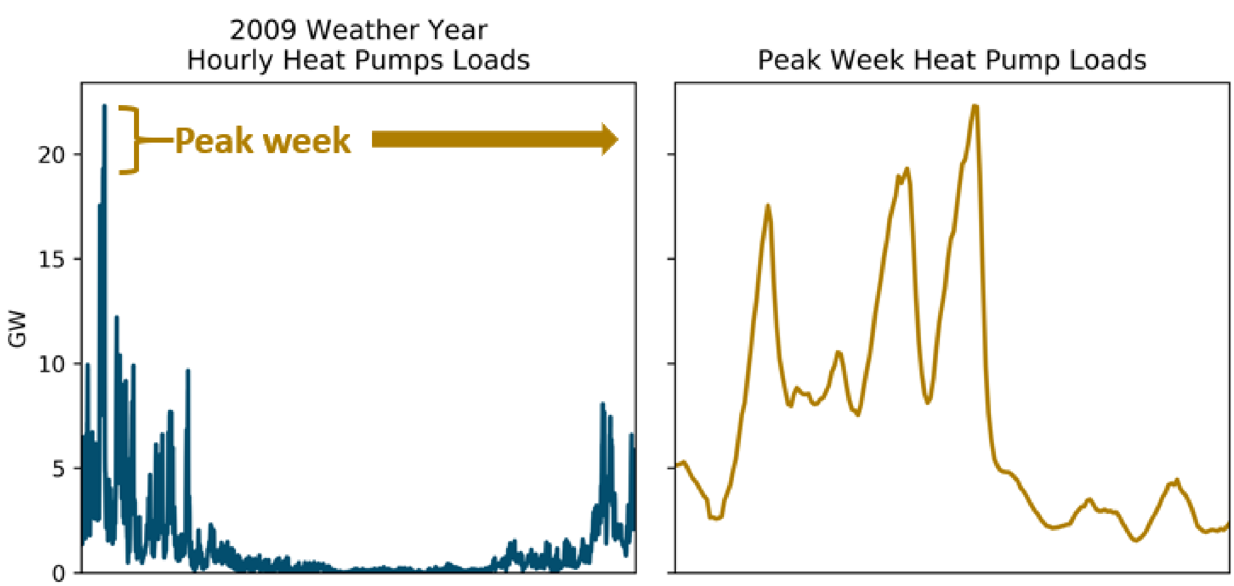


Figure 6: 2050 Residential Space Heat Load



Caveats and limitations

The load shapes developed through the above methodology offer an initial estimation of the scale of loads that follow from a near-complete electrification of space-heating in Minnesota. There are several factors that could make these loads higher or lower. Loads, particularly peak loads, could be higher if homes and businesses do not adopt cold-climate heat pump technologies. Loads could be lower if heat pump technologies continue to improve in cold-climate performance and if buildings heating loads are reduced through weatherization measures. Reduced heating loads decrease the amount of load in peak hours that must be covered by electric resistance back-up heat. Doing so pushes the non-linear portion of the load curve shown on Figure 4 to lower temperatures.

4 Simulating hourly loads

4.1 Forecasting hourly loads

In forecasting the Reference scenario, we project hourly loads by scaling up a historical year of Xcel Energy - Upper Midwest hourly loads according to the total energy in the forecast year. This methodology assumes that the load mix in the Reference scenario changes slowly enough that using a historical load shape will represent the Reference load shapes in the future. Although the Reference scenario has some changes in load across classes, the net load growth is small (0.24%/year) especially in comparison to the High Electrification scenario. Thus, we project hourly loads for the Reference scenario by scaling up each hour according to the total energy in the forecast year. For example, in 2009 the Xcel Energy - Upper Midwest annual load was 44.9 TWh; if the forecast year had an Xcel Energy - Upper Midwest load of 60 TWh we would scale up each hour by 1.33 (60/44.9 = 1.33) to calculate the hourly load for the Reference scenario in the forecasted year.

High electrification load

In calculating the High Electrification scenario load shape, we forecast the annual shape by layering on the incremental amount of electrification we expect in each of the load shaping categories. See Table 2 for the annual incremental electric load in the High Electrification scenario. In earlier years there is some amount of negative load due to efficiency gains[4], but in most categories we see load growth due to electrification.

Table 2. High Electrification scenario incremental annual electric load over Reference scenario (TWh)

	2015	2020	2025	2030	2034	2040	2045	2050
Space Heating	0.0	0.0	0.0	0.2	1.2	3.8	6.1	7.8
Water Heating	0.0	0.0	-0.1	-0.3	-0.2	0.2	0.6	0.8
Passenger EV	0.0	0.0	0.0	0.5	1.6	4.1	5.8	6.5
Other (Freight EV, Agriculture)	0.0	0.1	0.7	1.7	3.1	6.3	9.2	11.8

4.2 Downscaling Minnesota loads for the Xcel Energy - Upper Midwest service territory

[4] This is especially the case for water heaters. Transitioning to heat pump water heaters causes lower load growth than the Reference scenario through 2034

To calculate hourly load shapes for the Xcel Energy - Upper Midwest system, E3 scaled the Minnesota hourly load shapes to Xcel Energy's service territory across five Upper Midwest states. Based on historical energy data, in recent years Xcel Energy's retail sales in those five states have been on average 67% of total retail sales in Minnesota (Table 2). So E3's forecast of load and peak demand Minnesota-wide is multiplied by 67% to derive load and peak demand for the Xcel Energy - Upper Midwest system under this High Electrification sensitivity.

This approach assumes that the scaling of Minnesota loads to the Xcel Energy - Upper Midwest system stays constant over the forecast period. If electrification of transportation, water, and space heating has a different growth rate in our Upper Midwest service territories than in Minnesota as a whole, then both energy and demand impacts could be significantly different for Xcel Energy.

Space heating loads have a significant impact on the estimated peak load, especially in the 2040-2050 timeframe. Using this load shaping methodology for the Xcel Energy – Upper Midwest territory, the incremental peak impact of the High Electrification scenario over the Reference scenario grows from 430 MW in 2034 to over 14 GW in 2050, as the utility shifts from a summer peaking utility to a winter peaking utility due primarily to space heating demands. As noted in the load shaping section above, technology choice matters – foregoing building weatherization and cold climate heat pump technologies could make this peak demand even greater. Other peak mitigation options include non-electric thermal backup sources of heat, or managed load programs (like DR).

Table 2. Minnesota to Xcel Energy - Upper Midwest Scaling Factor[5]

	Xcel Energy - Upper Midwest Annual Load (MWh)	**Minnesota Annual Retail Sales (MWh)**	**Load Share**	
2009	44,923,739	64,004,463	70%	
2010	46,188,165	67,799,706	68%	
2011	46,133,452	68,532,708	67%	
2012	45,550,281	67,988,535	67%	
2013	45,177,181	68,644,103	66%	
2014	45,197,106	68,719,367	66%	
2015	44,565,009	66,579,234	67%	
2016	44,670,394	66,546,492	67%	
			67%	**Average**

[5] Source for Minnesota load: EIA state profile on retail sales for 2009 to 2016

APPENDIX F5 – GENERATION INTERCONNECTION COSTS METHODOLOGY

Xcel Energy Transmission Planning – White Paper
Generation Interconnection Costs using Random Placement Techniques
June 27, 2018

I. PURPOSE

The purpose of this paper is to articulate Transmission Planning's efforts to create a process to identify interconnection costs associated with renewable generation on the Northern States Power (NSP) System using Monte Carlo simulations.

A. Background

Resource Planning approached Transmission Planning to see if there was a way to identify average transmission upgrade costs associated with solar installations. Running individual cases to create a statistically significant amount of results using the Siemen's PSSE program would be time consuming. Transmission Planning decided to try and develop a Monte Carlo type process to see if we could speed up the process to allow for a large amount of generation placed randomly around the system.

The runtime for each case depend on the amount of contingencies that are chosen to run and the portion of the system you choose to monitor. In addition the case chosen based on its size will greatly affect the runtime (MISO cases vs equivalized MNTACT cases). MNTACT cases used for local NERC reliability have been reduced in size by taking remote areas of the eastern interconnection and equivalizing them into a simple load and gen on one bus representing their system. This has the effect of reducing the overall case size and improves runtime.

The sample size needs to be of significant number to be considered statistically significant to produce a believable average. Typically the confidence interval (CI) is affected by the size of the statistical sample. The larger your sample size the lower the margin of error is. Since the number of possible random generation configurations is infinite a sample size of 100 was chosen based on size and time considerations.

B. Analysis

To create a large amount of random topology cases for analysis purposes Transmission Planning proposed incorporating the Python Coding interface with Siemens PSSE program using the API.
The process steps are outlined below:

1. Choose the amount of Monte Carlo runs (a minimum amount for statistical significance)
2. Identify and solve two benchmark cases to mimic the MISO process (MISO generation assumptions are used to dispatch)
    a. Summer peak (solar 100%)
    b. Shoulder (solar 50%)
3. Choose the random amount of new solar generation to be studied
    a. 69 kV: 3-20 MW
    b. 115-230 kV: 50-100 MW
    c. 345 kV: 200 MW
4. Use Python Code to randomly place solar generation around the NSP and GRE systems up to the amount chosen
    a. Python Code will then readjust MISO system generation down to accommodate the new generation addition. This process chooses generation units that are already on-line to be readjusted down in small increments to prevent the area swing bus from taking the full amount of new generation and thus reducing solving errors.
5. The two new summer and shoulder cases are created with new generation mix
6. ACCC is run on both new created cases
7. A compare is run against output from new cases compared to benchmark cases
8. Thermal overload costs are assigned based on newly created overloads or 3% greater difference than benchmark case
    a. Voltage issue costs were not tracked due to the difficulty in determining validity of identified voltage issues
9. Output thermal overload costs are plotted on scatter graph and a mean is identified for Monte Carlo run

C. Business Benefits

Monte Carlo analysis is used in most other industries to examine probabilistic outcomes using random input variable assumptions. It is heavily used in the finance industry to test financial models over good and bad markets. Traditional transmission planning studies involve a large amount of time in both the model development and the output analysis. Verification of all identified transmission issues and verification of contingencies consume a large amount of time. This type of analysis is typically what is required for reliability projects to comply with NERC standards.

Applying Monte Carlo simulation to the power systems will allow us to test future scenarios over a wide range of inputs and develop likely outcomes. The Monte Carlo approach will not replace the traditional reliability studies currently run to meet NERC criteria, but instead will allow us to develop probabilistic futures for changing generation or load mixes based on future assumptions.

D. Summary

When considering the rapidly changing world related to the power system, Monte Carlo simulations will allow Transmission Planning to develop future probabilistic models to help give insights into future assumptions. This type of random analysis will allow for a large amount of future assumptions to be screened quickly. For the generation example above it can be replicated for any amount of generation, type, or general location.

Future applications for stability are a possibility requiring further examination.

APPENDIX F6 – RESOURCE OPTIONS

I. INTRODUCTION

The main goal of resource planning is to evaluate the size, type, timing and sometimes location of resources we plan to procure to meet customer needs over the next several years. To do this, we take into account key planning considerations, such as carbon reduction goals, reliability, affordability and potential future risk. Over the course of the 2020-2034 planning horizon, our customers' gross peak demand needs are expected to grow from approximately 10,500 MW to just over 11,700 MW, before accounting for Demand Side Management (DSM) adjustments. While we are currently long capacity, a substantial portion of our resources will either reach planned retirement or end of contract dates over the planning period, per our Preferred Plan. As a result, our modeling shows a capacity deficiency in the mid-2020s timeframe. Our Resource Plan addresses how the Company proposes to fill this gap by identifying an appropriate mix of future resource additions.

To identify this mix the Company developed a set of generic resources for inclusion in Strategist modeling, with size, cost, and performance assumptions that reflect updated information from project experience, public stakeholder meeting input, and independent third party studies. Future resource options can be generally categorized as supply-side resources, and demand-side resources. We also evaluated potential transmission cost implications associated with supply-side centralized resources, given current transmission capacity constraints in MISO. Paired with existing owned resources and contracts, this set of generic resources was evaluated in Strategist modeling to determine optimal future resource portfolios, in light of the different scenarios and sensitivities we tested.

II. EXISTING RESOURCES

The Company owns and has under contract approximately 13,500 MW of capacity currently, although as stated above, many of our current resources are slated to retire over the planning period. Below we include discussion of each resource type, and tables showing: each generating unit, whether it is owned or contracted, capacity we own or contract,[1] and the retirement year if known, as reflected in the Strategist model. These numbers have been rounded to the nearest whole number for simplicity, where applicable. It should be noted that the capacity numbers provided below are the maximum values included in the Strategist modeling, and may differ

[1] Expected as of 2020.

marginally from official nameplate or ICAP values.

A. Coal

The Company owns and operates four coal-fired power plants, with a total capacity of 2,390 MW. Planned retirement dates for Sherco 1 in 2026 and Sherco 2 in 2023 were approved in our last Resource Plan, and existing retirement dates for King and Sherco 3 are 2037 and 2040 respectively. As part of our Preferred Plan, we are proposing to retire these two facilities a decade early; where AS King and Sherco 3 would retire in in 2028 and 2030, respectively.

Table 1: Existing Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Allen S King	Steam Turbine (ST)	Own	511	2037
Sherco 1	ST	Own	680	2026
Sherco 2	ST	Own	682	2023
Sherco 3[2]	ST	Own	517	2040

B. Nuclear

The Company owns and operates three nuclear power plants with a total capacity of 1,738 MW. These units operate at very high capacity factors and provide nearly 30 percent of the energy for our system. They have also both achieved operating costs reductions of over 20 percent from 2015 levels, and both produce energy for our system for under $30/MWh. The existing retirement dates for the nuclear facilities are reflected in the table below. In our Preferred Plan, we propose to extend Monticello plant operation to 2040.

[2] This represents the portion of Sherco 3 under our ownership.

Table 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	646	2030
Prairie Island 1	Pressurized Water Reactor (PWR)	Own	546	2033
Prairie Island 2	PWR	Own	546	2034

C. Natural Gas and Oil

The Company owns or maintains Purchase Power Agreements (PPAs) with many natural gas facilities. Our current natural gas generators are configured as either simple-cycle Combustion Turbines (CTs) or a Combined Cycle Gas Turbine (CCGTs or CCs). The CTs are located at seven different sites and provide peaking capacity meaning they are only typically 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.

Our current natural gas and oil fleet provides nearly 4,780 MW of dispatchable capacity. Resource portfolio provides a combined with varying retirement dates In the list of resource below, we provide the capacity and anticipated retirement dates for the Mankato CC assuming we own the resource, per our proposed acquisition in Docket No. IP6949, E002/PA-18-702; however, the Company currently has a PPA for energy and capacity with each of the Mankato CC units. The second unit began commercial operation in June 2019.

Table 3: Existing Natural Gas and Oil Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity	Existing or Planned Retirement/Contract Expiration
Black Dog 52	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center[3]	CC	Own	762	2046, 2054
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-4	CT	Own	386	2034
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2034
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	Oil	Own	191	2023
French Island 3,4	Oil	Own	160	2027
Wheaton 6	Oil	Own	70	2025

D. Biomass

The company owns and operates, and maintains PPAs with, 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 160 MW of capacity on our system.

[3] Note: As stated above, we have modeled Mankato Energy Center as an owned resource. Approval of this acquisition is pending in Docket No. IP6949, E002/PA-18-702.

Table 4: Existing Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	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
KODA Energy	Bio	PPA	12	2019
St. Paul Cogen	Bio	PPA	24	2023
WM Renewable Energy	LND	PPA	4	2020
Gunderson	LND	PPA	1	
Barron County	RDF	PPA	2	2022
Hennepin Energy Recovery Center	RDF	PPA	34	2024
Diamond K. Dairy[4]	DIGT	PPA	0.4	2023
Greenwhey	DIGT	PPA	3	
Heller Dairy	DIGT	PPA	0.5	

E. Hydroelectric

The Company owns, operates and maintains PPAs for hydropower resources with a number of different counterparties, totaling over 680 MW. The majority of our current hydro capacity is provided by our PPAs with Manitoba Hydro, which expire in 2025. We also have an additional 125 MW PPA with Manitoba Hydro that is slated to start in 2021. Further, the Company 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.

[4] Note: This unit is included in Strategist modeling, but its PPA was terminated as of April 2019.

Table 5: Existing Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Byllesby	Hydro	PPA	2	2021
Hastings	Hydro	PPA	4	2033
St. Cloud	Hydro	PPA	9	2021
Dairyland	Hydro	PPA	4	-
Eau Galle	Hydro	PPA	0.3	2026
DG Hydro	Hydro	PPA	0.4	-
LCO Hydro	Hydro	PPA	3	2021
Neshonoc	Hydro	PPA	0.4	2020
Rapidan	Hydro	PPA	5	2020
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	Hydro	PPA	371	2025
Manitoba Hydro	Hydro	PPA	125	2025 (2021 start)

F. Wind

The Company owns or contracts for over 2,600 MW of wind power. Over the next two to three years, the Company intends to add 1,850 MW of wind generation from recent acquisitions and Requests for Proposal (RFPs), as well additional capacity to serve other customer programs.

Table 6: Existing and Near Term Wind Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Big Blue	Wind	PPA	36	2032
Chanarambie	Wind	PPA	86	2023
Community Wind North	Wind	PPA	26	2044
Fenton	Wind	PPA	206	2032
McNeilus Group	Wind	PPA	37	2028
Jeffers	Wind	PPA	44	2044
MinnDakota	Wind	PPA	150	2022
Moraine II	Wind	PPA	50	2029
Community Wind South (Zephyr)	Wind	PPA	31	2032
Lake Benton I	Wind	PPA	104	2028
Lake Benton II[5]	Wind	PPA	104	2019
Odell	Wind	PPA	200	2035
Prairie Rose	Wind	PPA	200	2032
FPL Mower Co	Wind	PPA	99	2026
Ridgewind	Wind	PPA	25	2031
Border	Wind	Own	150	2040
Courtenay	Wind	Own	200	2041
Grand Meadows	Wind	Own	100	2033
Nobles	Wind	Own	200	2035
Pleasant Valley	Wind	Own	200	2040
Crowned Ridge (Owned)	Wind	Own	300	2044
Freeborn	Wind	Own	200	2045
Foxtail	Wind	Own	150	2044
Blazing Star I	Wind	Own	200	2044
Blazing Star II	Wind	Own	200	2045
Lake Benton Repower	Wind	Own	100	2044
Dakota Range 1 & 2	Wind	Own	300	2046
Dakota Range 3	Wind	PPA	150	2032
Clean Energy	Wind	PPA	100	2039
Crowned Ridge (PPA)	Wind	PPA	300	2044
Small Wind[6]	Wind	PPA	285	Various

[5] Note: this unit is being repowered; the repower is reflected as a separate line item in this table ("Lake Benton Repower").
[6] Includes PPAs of 20 MW or less

G. Solar

By 2020 the Company anticipates it will maintain a total of 990 MW of solar capacity, via PPA, to serve our customers. This includes approximately 260 MW of large grid-scale solar, over 640 MW of Community Solar Gardens (anticipated by 2020), and nearly 90 MW of small-scale distributed solar.

Table 7: Existing 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	2036
Other RDF Solar	PV	PPA	2	
Aurora	PV	PPA	99	2036
Marshall	PV	PPA	62	2042
North Star	PV	PPA	99	2041
DG Solar[7]	PV		86 (2020)	Various
Community Solar Garden	PV	PPA	641(2020)	Various

III. GENERIC FUTURE RESOURCE OPTIONS

Consistent with past resource plans, we have developed generically-defined resources to use in Strategist modeling, from which the model can select when resource retirements or PPA expirations result in our remaining portfolio falling short of future projected demand. Cost and performance data for these resources was developed using a mix of third party studies and forecasts such as the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), consultant estimates, and internal Company data. Generic resources are intended to help identify the general size, type, and timing of resource needs in the future and do not typically represent a specific resource at a specific location, or whether such a resource would be owned or contracted. Rather, these specific details are determined via a competitive acquisition process that is held after the general size, type and timing has been established and approved in the Resource Plan proceeding.

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

It is important to highlight that the Company worked closely with and solicited feedback from stakeholders to select the best sources and methodologies to employ in developing generic resource options. Our stakeholder interactions, and direction from our regulators, resulted in a number of refinements to our past assumptions. We believe these adjustments improved the quality of our modeling and highlight the benefit of our proactive approach to stakeholder engagement.

A. Supply Side Resources

Supply-side centralized resources are traditional large-scale thermal and renewable generation facilities. We have included a number of supply-side centralized fuel types in our modeling; large-scale wind and solar, a variety of natural gas resource options, and battery energy storage. Their attributes, and the method by which we developed each one, are described further. We also detail specific resource cost and performance assumptions in Appendix F2, unless otherwise noted.

1. Wind

Our generic wind resource option was sized at 750 MW on nameplate capacity basis. While the size of this generic wind resource may seem relatively large, we account for the MISO accredited capacity value for new wind resources as 15.6 percent[8] of this total, or about 117 MW. Given our modeling selects resources on the basis of their accredited capacity, and given the size of our system, and magnitude of future capacity needs, we feel this sizing represents an appropriate approach to modeling generic wind additions.

We derived forecasted wind costs used in our modeling from publicly available data from the NREL 2018 ATB Levelized Cost of Electricity (LCOE) data. This cost has been further adjusted for tax credit effects in relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with a greenfield generation facility, as described further below.

2. Solar

Our generic supply-side large-scale solar resource is sized at 500 MW on a nameplate capacity basis. Similar to wind resources, it is important to note that the MISO accredited capacity value for solar is discounted by 50 percent, thus the Strategist model considers generic solar additions in 250 MW firm capacity increments. This

[8] Reflecting the wind capacity accreditation value for Planning Year 2018/2019.

accredited capacity size increment is comparable to other generic resource assumptions, and thus evaluating solar in this size increment is appropriate.
We derived forecasted solar costs from the publicly available LCOE data in the NREL ATB as well. Similar to the adjustments for wind resources, this cost has been adjusted for tax credit impacts in the relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with greenfield generation facilities, as described further below.

Our modeling also includes a forecast of distributed solar adoption, applied as a supply-side resource with an assumed adoption rate. In addition to these static forecasts, we had planned to include distributed residential and commercial solar as generic resource options in the modeling. However, we ultimately found these resources would not be selected by the model and eliminated them from the optimization exercise. We feel this is justified, as generic distributed solar continues to be significantly more expensive, on a levelized cost of energy (LCOE) basis, than large-scale solar. This cost delta exists even when including transmission costs for large-scale solar, and as a result, it would be highly unlikely that distributed solar would be selected in our scenario optimizations where the model could choose less expensive large scale solar instead. Therefore, to improve model runtimes and reduce truncation issues, as discussed in Chapter 4: Preferred Plan, distributed solar was included at an assumed adoption rate and not further optimized in the Strategist model.

Please see Appendix F1 for more information regarding distributed solar forecasts.

3. Natural Gas

We have included three potential generic resource configurations for natural gas, given the different types of generator and location types. Specifically, we have included options for both CT and CC generic units. Based on our pre-screening review of cost and performance data available from major equipment suppliers and construction contractors, we developed generic resource options based on those we felt had the best economic viability in our system.

For CTs we developed two generic options, differing in size, configuration, and whether the site would be green- or brown-field, based on the available external data noted above and internal engineering assessments. For CCs, we developed one generic option, and applied similar methods to identify appropriate generator cost and performance assumptions from external sources and internal engineering assessments. Here, however, we depended upon an external consultant analysis to better understand potential interconnection costs across several greenfield sites, given increased complexity of siting a several hundred MW gas generation unit and navigating the current MISO generator interconnection process.

4. *Battery Energy Storage*

For the first time in this IRP process, we have developed a generic four-hour battery energy storage resource to include in our Strategist modeling. The unit is sized at 331 MW, which we selected based on both our understanding of our system's future capacity needs and to ensure size parity with one of our generic CT options. Our resource cost assumptions are based on bids our Public Service Company of Colorado operating company received in response to a late 2017 all-source solicitation. To forecast future costs, we applied NREL ATB estimated technology learning curves to these internal cost estimates. For more discussion on storage, see the Minnesota Energy Storage Assessment in Appendix F7.

B. Demand Side Management (DSM)

Based on external studies and stakeholder feedback, we have updated our approach to modeling DSM resources in this Resource Plan, as compared to past years. The Company utilized a *Demand Response Potential Study* provided by the Brattle Group (Appendix G2) and a *Minnesota Energy Efficiency Potential Study*[9] prepared for the Minnesota Department of Commerce, Division of Energy Resources to convert DSM resources into supply-side option "Bundles," which could compete against other resource alternatives in Strategist modeling. Our approach to developing Bundles from the information provided in the study is described below.

1. *Energy Efficiency (EE)*

Based on external studies and internal expertise, the company developed three Bundles, termed Program, Optimal, and Maximum. Internal experts provided detailed cost, and energy and demand avoidance characteristics, for the three Bundles by year. Each Bundle is included in Strategist as a supply-side resource the model could potentially select. The Program and Maximum Bundles are based on the 2018 *Minnesota Energy Efficiency Potential Study* findings. The Optimal Bundle was developed by the Company using the study results for optimal demand reduction (as opposed to energy reduction). Each Bundle included in our resource modeling is incremental to the last, and selection of any Bundle is dependent on the Bundle before it being

[9] Study available at: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected).

2. Demand Response (DR)

Similar to the process for EE, we developed Demand Response (DR) Bundles, so that DR could be treated as a supply-side resource in the Strategist modeling. Consistent with past practice, the Company developed a Base DR Forecast from existing programs, which was included in all baseline resource modeling. The Company then developed three DR Bundles incremental to the Base DR Forecast, based on the Brattle Study noted above. The DR Bundles were designed by taking a point-in-time supply curve of DR options in the study, and developing more detailed annual demand reduction and cost characteristics by year. The Bundles were generally sized to account for supply curve price thresholds, with Bundle 1 achieving demand reduction of 270 to 542 MW; Bundle 2 achieving an incremental 107 to 242 MW; and Bundle 3 achieving an incremental 89 to 112 MW during the planning period. Similar to EE, the DR Bundles are incremental to each other and dependent on the preceding Bundle being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected).

C. Transmission Costs for Greenfield Resources

In addition to generating resource assumptions, our Strategist modeling also includes transmission cost considerations for new greenfield resources. These values are intended to capture the transmission expansion and/or interconnection costs required to successfully integrate new greenfield resources into the system. Given current challenges with the MISO interconnection process, and shrinking available transmission capacity on the system, significant study delays and major upgrade costs are likely to result in elevated transmission costs for future resources. Therefore, the Company engaged in a number of internal and external studies in order to appropriately represent anticipated transmission costs associated with new greenfield CT, CC, wind and solar resources. To assess CC transmission delivery costs, the Company hired Excel Engineering, a third party consultant, to perform a study that evaluated potential costs for six different locations on the system. The study identified the potential for high interconnection costs at all of the potential site locations, ranging from a low of $263 million to a high of $1,354 million. Cost levels in this study are dependent in part on the percentage of planned projects that withdraw from the MISO queue. Excel Engineering's Interconnection Cost Estimates is included in Appendix R.

To assess wind and solar transmission delivery costs, the Company's internal Transmission Planning Group performed a random placement technique study. This study identified and solved two benchmark cases to mimic the MISO process. Next, new solar capacity was added at random locations, in order to study the modeled effect on the transmission system. These results were then compared back to the "benchmark" study, to help identify transmission system violations. Finally, interconnection cost estimates were developed by estimating the costs necessary to remedy the violations identified in the study. This methodology is further explained in Appendix F5.

IV. POTENTIAL RESOURCES NOT CONSIDERED IN MODELING

The Company considered several additional technologies in the initial screening process that, in the end, were not included in modeling. We discuss these resources and why they were not included below. We will continue to monitor and screen these options for possible inclusion in future Resource Plans, and/or allow them to compete in future competitive resource acquisition processes, in order to gain additional information on their potential costs and operating characteristics.

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 biomass resources are substantially higher than those associated with generic wind, solar, and natural gas resource options. As a result, the Company did not include a generic biomass resource for consideration in the modeling.

We anticipate, however, that future acquisition processes may allow biomass resources to compete in resource solicitations. There are also existing biomass resources in our region that may be available to help meet our future resource needs. If found to be cost competitive, they could be selected to displace other generic options identified in our Plan.

B. Combined Heat and Power (CHP)

CHP was not included as a generic resource option, as studies indicated it will have limited economic potential during the planning period. The Company engaged the 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 estimates a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential in Xcel Energy's Minnesota service territory. Under the base scenario, CHP adoption is estimated at 43 MW through 2039. We provide the study as Appendix S.

C. Nuclear

Nuclear is an important, reliable resource that helps contribute to our carbon-free portfolio. There are a number of existing and new nuclear technologies currently being considered for future deployment; however, while these technologies appear promising, there remain commercial barriers to adoption such that we did not include them as generic resource options for our plan. Outstanding commercial uncertainties include:

- Technological maturity and component manufacturing experience
- Risks and costs related to construction delays and/or budget overruns
- Options for disposal of spent nuclear fuel from new facilities
- State and federal regulatory barriers or uncertainty

Of note, Minnesota state statute currently prohibits the Commission from issuing a Certificate of Need for the construction of a new nuclear facility.[10] We further discuss emerging nuclear technologies in Section V below.

D. 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 highly 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. Similar to biomass resources, the Company remains willing to evaluate pumped hydro projects in future resource solicitations, and if cost effective, pumped hydro resources could displace generic resource options identified in this Plan.

E. Coal

New generic coal resources were eliminated from the list of resource options due to cost, environmental challenges, and non-alignment with our strategic goals. Capital costs for generic coal resources are high relative to new gas and renewable resource options. Low natural gas prices, increased renewable penetration, and regulatory risk

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[10] Laws of Minnesota 1994, Chapter 641, Article 2, Section 1, Subd. 3b.

create additional challenges and major risks for new coal resources. Furthermore, adding coal resources with high carbon emission levels would not align with our commitment to deep carbon reduction on our electric system. For these reasons, we have excluded new coal resources from our modeling. While the Company will continue to monitor carbon capture and sequestration technology developments, we do not expect to consider new coal resources in future resource plans.

V. EMERGING TECHNOLOGIES

As we have previously stated, we can achieve our 2030 carbon reduction goals with existing technologies; however, achieving our vision of a carbon-free electricity supply by 2050 will require significant technology 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 also keeping our electricity affordable for customers. We are continually assessing new technologies that may be viable options for future resource planning cycles. Below we present a non-exhaustive list of example technologies we are currently tracking.

A. Allam Cycle Application for Emissions Capture in Natural Gas Plants

The Allam Cycle uses natural gas to produce power, but in a different fuel burning process than traditional CTs. Instead of using ambient air for combustion directly, the plants burn natural gas with pure oxygen generated within an Air Separation Unit. This "oxy-combustion" produces CO2, which is then used in the plant's electricity generation process. Using pure oxygen rather than ambient air eliminates nitrogen oxide emissions from the plant's process. The CO_2 released from the combusted natural gas is captured within the plant's process and reused to support additional cycles of fuel combustion. Heat energy is also recovered and used in the process. Excess CO_2 not needed for energy generation can be stored or used in other industrial processes.

NET Power, a company working to commercialize this technology, has recently finished a demonstration project in Texas that is providing power to local customers and undergoing testing to connect to the broader transmission system. They are also working to develop a larger commercial facility with Occidental Petroleum.[11] While this technology remains more expensive than conventional gas plants, we will

[11] *See* Patel, Sonal. "Insite NET Power: Gas Power Goes Super-critical." Power Mag (April 2019). Available at: https://www.powermag.com/inside-net-power-gas-power-goes-supercritical/

continue to monitor this and other potential developments in carbon capture and storage for potential future application in our system.

B. Hydrogen for Power Generation

Hydrogen is another fuel with potential to support dispatchable carbon-free generation as burning hydrogen, by itself, does not produce any carbon emissions. In existing applications; however, hydrogen is typically mixed with natural gas, which has the effect of lowering a plant's CO_2 emissions levels. Introducing hydrogen into the fuel mix for an existing gas plant does not always require substantial plant retrofits. In fact, some conventional gas turbines are already capable of burning hydrogen in low-to-medium concentrations. For higher concentrations, more significant plant configuration changes are likely required.[12]

There are several methods of producing the hydrogen that would be burned in these units, from using existing industrial process byproduct hydrogen to producing it in dedicated water electrolysis facilities. Current methods like water electrolysis are, in themselves, energy intensive, and as such can make using hydrogen for electricity generation expensive. As the share of variable renewables on the electric grid increases, however, these processes may be able to use inexpensive (or negative priced) excess energy in some hours of the day to reduce the cost of producing the hydrogen. In this sense, hydrogen derived from renewable energy serves as a long duration storage option, where the fuel can be stored over days, weeks or months until needed and burned in a dispatchable plant without any carbon emissions.[13]

Pilot projects in Germany and Denmark, for example, are currently testing using excess wind generation to produce hydrogen through electrolysis[14] that can then be used as needed in a retrofitted natural gas generation plant. Various companies, including leading CT suppliers and startups, are working to further develop and commercialize both the turbines that can run on higher levels of hydrogen and the electrolysis facilities that would produce hydrogen using excess clean energy. We continue to monitor technology progress in the hydrogen space, to evaluate the

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[12] Goldmeer, Dr. Jeffrey. "Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem." General Electric Company (May 2018). Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf

[13] *Id.*

[14] Fairley, Peter. "Europe Stores Electricity in Gas Pipes." Scientific American (April 2019). Available at: https://www.scientificamerican.com/article/europe-stores-electricity-in-gas-pipes/

potential for our gas generation assets to convert to hydrogen use in the future. We are also exploring ways to use electricity generated from our nuclear units to generate hydrogen through on-site electrolysis.

C. Emerging Nuclear Technologies

Nuclear power is one of the most reliable and lowest operating cost resources we have in our system. Our two nuclear plants provide nearly 30 percent of our electricity mix, carbon-free and at a cost (fuel and O&M) below $30/MWh. However, it is increasingly difficult to build new conventional nuclear units, in part due to their typical scale and associated high upfront costs.

Substantial industry research into several advanced nuclear technologies is ongoing. For example, in recent years there have been renewed efforts to develop advanced reactors that use sodium, gas or liquid metals in place of traditional cooling materials. Renewed research is also ongoing into applications wherein the nuclear fuel itself can be dissolved into molten salt, in order to operate at lower pressures than traditional pressurized water reactors. Using molten salt in this way is intended to improve safety considerations. Some advanced reactor designs are intended to reduce spent fuel volumes, by either enabling longer durations between refueling events or instituting closed fuel cycles that reprocess and reuse spent fuel within the reactor. Reducing spent fuel volumes can both reduce fuel costs and mitigate spent fuel storage challenges. Some designs also incorporate passive safety designs through natural convection cooling.

Other developers are researching potential application of light water reactor technology to small modular reactors (SMR). SMRs would be intended to be more flexible, able to serve smaller scale needs, and allow reduced backup infrastructure, as compared to existing nuclear units. This general concept is already used in military applications and for marine vessels that need to go long periods between refueling. SMRs are typically less than 300 MW in size and factory fabricated in modular units. The modular design is intended to enable streamlined production, shipping, and installation processes, in order to help manage costs. Further, the units are intended to go longer in between refueling outages than conventional plants, and allow refueling of one unit as the others continue to operate.[15] As an emerging technology, however, it is not yet clear whether SMR costs will be competitive with other sources of energy.

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[15] *See* "Benefits." NuScale Power. Available at: https://www.nuscalepower.com/benefits

Several companies are currently working through NRC licensing processes for emerging nuclear technology, with the goal of attaining design approval for their advanced and small modular reactors by the mid-2020s, in order to complete pilot plants in the late 2020s.

D. Energy Storage Advancements

Large scale battery energy storage is increasing its presence on the grid, being used to integrate renewables, defer grid investments, and more. In fact, the Company has had a sodium-sulfur battery operating on the NSP System since 2009, in order to gain valuable technology experience.[16] Many batteries installed today use lithium-ion (li-ion) chemistries, benefitting from economies of scale gained in consumer electronics and, to some extent, electric vehicle manufacturing. Grid-scale li-ion batteries typically store energy for relatively short durations, providing a few hours of capacity or energy services.[17] While these shorter duration batteries hold great promise to mitigate demand peaks or short periods of intermittency now, in the long term with higher renewable penetration, the grid will need a combination of short and longer duration storage capabilities to effectively match variable renewable output to customer load. Further, costs for short and longer duration storage will need to decline further for energy storage to be deployed at scale.

To this end, there are several emerging storage applications that either use different chemical and physical properties, with the goal of mitigating cost and/or duration challenges. A few examples of emerging energy storage technologies we follow include:

- **Solid state li-ion batteries**: Current li-ion batteries, while continuing to become more cost effective for stationary storage applications, use a liquid electrolyte that has room to improve in terms of energy density. Development is underway that would replace the liquid electrolyte with solid materials, that offer higher energy densities and reduce potential for leakage and flammability. Solid state batteries hold promise to reduce the cost of energy storage, because increasing energy density allows more energy to be stored for discharge when needed. They also hold promise in increasing the number of times the battery can cycle before requiring material replacement.[18] These batteries are not yet

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[16] The Luverne MinnWind Storage Project is a 1 MW, 7MW-h sodium sulfur (NaS) battery paired with an 11 MW wind facility in western Minnesota.
[17] As noted above, our modeling included a 4-hour duration generic battery energy storage option, which we believe is in line with most commercialized grid-scale lithium ion batteries installed currently.
[18] Tohoku University. "Highest energy density all-solid-state batteries now possible." ScienceDaily. (March

commercially available, but there is substantial interest in continuing development. Large industrials – such as Samsung, Hyundai, and Solvay – and venture funds such as Breakthrough Energy have invested in startups developing the technology.[19]

- **Flow batteries**: Flow batteries are a category of technology that includes several types of chemistry compositions. While not a new technology in general, application to stationary power system remains relatively nascent. In general, flow batteries are a cross between a conventional battery and a fuel cell, where a liquid electrolyte cycles through a core, and ion transfers between the cathode and anode generates electricity. As such, flow batteries tend to have favorable life cycles and may provide longer duration storage than li-ion designs; as the electrolytes are separate from the cell itself, the tanks can be scaled up without also scaling up the cell. However, round trip efficiency can be lower than in lithium-ion batteries, and this application has not been proven to serve substantially longer durations than lithium-ion.[20] [21] San Diego Gas & Electric, a utility in California, has recently installed a flow battery to its grid for a four year pilot project, where it will evaluate battery economics, renewable integration, and wholesale market services potential.[22]

- **Electrothermal energy storage**: Thermal storage for renewables has been implemented in limited use cases. There are, for example, existing large scale solar thermal facilities in the desert southwest that use large tanks of molten to store energy in the form of heat, across several hours or even days, until needed. This concept has not traditionally been applied to solar PV or wind facilities; however, a company called Malta is working to develop Carnot batteries (i.e. pumped thermal storage) that could be deployed either at greenfield or brownfield locations. Their concept converts the electricity from a solar PV or wind facility into thermal energy through a heat pump. Heat can be stored in molten salt while cold is stored in a chilled liquid. To discharge the energy, transfer fluid is run through both the hot and cold storage tanks, creating steam that can be used to convert the energy back into electricity. This

2019). Available at https://www.sciencedaily.com/releases/2019/03/190322105701.htm

[19] Wesoff, Eric, "Industry Giants Samsung and Hyundai Invest in Solid-State Batteries." Greentech Media (September 2018). Available at: https://www.greentechmedia.com/articles/read/industry-giants-samsung-and-hyundai-invest-in-solid-state-batteries

[20] Dagget, Jamie. "Can Flow Batteries compete with Li-ion?" DNV GL (January 2019). Available at: https://blogs.dnvgl.com/energy/can-flow-batteries-compete-with-li-ion

[21] "Flow Batteries." Energy Storage Association. Available at: http://energystorage.org/energy-storage/storage-technology-comparisons/flow-batteries

[22] "California ISO Adds Flow Battery to the Grid." T&D World (May 2019). Available at: https://www.tdworld.com/energy-storage/california-iso-adds-flow-battery-grid

system is intended to provide longer duration storage, with a longer facility life and at lower capital cost than a typical battery storage facility.[23] In Germany, Malta and other partners are working to develop a pilot project on a brownfield coal site, in order to repurpose the steam turbine to generate electricity from the stored renewable energy.[24]

- **Subsurface pumped hydro storage**: Pumped hydro storage has been the primary method of long duration storage on the grid for many years, including the Company's own Cabin Creek pumped hydro facility in the Colorado service area. As noted above, however, we have not included it in our generic resource modeling due to dependence on specific geologic structures and related challenges in estimating generic costs. There are, however, companies working to provide scalable pumped hydro solutions that can be built in areas without the typical geologic structures. For example, a company called Quidnet is proposing to use conventional reservoir technology and typical oil and gas well practices to create subterranean compressed hydro storage facilities. To store energy, water would be pumped down into an underground well and held under pressure in the rock formation. When energy is needed, the pressure would be released and the water would flow through a conventional hydro turbine to generate electricity. This system is intended to be closed loop, to conserve water. The necessary underground rock structures are also more ubiquitous, and the plants can be more flexible in scale than conventional pumped hydro storage.[25]

23 "Projects: Malta." Google X. Available at: https://x.company/projects/malta/
24 Deign, Jason. "Germany Looks to Put Thermal Storage Into Coal Plants." Greentech Media (March 2019). Available at: https://www.greentechmedia.com/articles/read/germany-thermal-storage-into-coal-plants
25 "Solution." Quidnet Energy. Available at: http://www.quidnetenergy.com/

APPENDIX F7 – MINNESOTA ENERGY STORAGE SYSTEMS ASSESSMENT

I. INTRODUCTION

In the 2019 legislative session in Minnesota, there was legislation passed as a part of the jobs, economic development, energy, and commerce omnibus bill amending Minnesota Statutes 2018, section 216B.2422 to require utilities to include an assessment of energy storage systems in their resource plan filing. The full text of the legislation is included below:

> 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).
>
> **EFFECTIVE DATE.** This section is effective the day following final enactment.

In this Appendix, we include background on Xcel Energy's growing experience with energy storage technologies, a narrative on the values that storage can provide to the system, some of the shortcomings of current storage technologies, and how we analyzed energy storage as a part of this Resource Plan.

Xcel Energy's long-term carbon strategy depends on the deployment of advanced clean technologies. We expect grid-scale energy storage to play an important role in our long-term plans. While we do not anticipate significant reliance on battery storage resources in this plan for the Upper Midwest in the near term, we are piloting storage technology across our system to test the capabilities, and will look for opportunities for more aggressive deployment of these resources in the future as we have generation capacity needs.

As discussed in more detail below, grid-scale storage can help integrate increasing levels of renewable resources. Storage can also provide other system benefits, including more reliable grid operations, voltage support, and frequency control. Utilities are already taking advantage of many different values of grid-scale storage. In fact, utilities are the leading developers of storage technology in the nation. As grid owners and operators, utilities are uniquely situated to maximize the potential benefits of storage. As detailed further in this Appendix, Xcel Energy has a number of advanced storage projects already deployed on our system and a growing interest in using storage in the future.

At the same time, we recognize that storage today has limitations. We discuss here three significant challenges for storage: First, storage cannot today solve the problem of the wide seasonal variation in renewable energy generation, which is the chief factor preventing the creation of fully renewable electricity system. Second, while storage can initially help integrate renewables by moving energy from the time it is produced to when it is needed, the value of each additional increment of storage capacity declines as more is added to the system. Finally, although storage can provide multiple services to the grid – power quality and grid support, for example – the value of all of these services are not all additive (or "stackable"). As a general rule, these services are not all available at the same time. Despite these limitations, we are bullish on the potential of storage as a part of our electricity system.

II. XCEL ENERGY'S ENERGY STORAGE EXPERIENCE

Electricity storage devices include a variety of technologies that store electrical energy directly (e.g. capacitors) or, more typically, after converting to some other form of potential or kinetic energy. For example, pumped hydro storage facilities use electrical energy to pump water to a higher elevation and store that water as gravitational potential energy; flywheels use electrical energy to rotate a mass to high velocities and thus store energy as kinetic energy; compressed air projects store energy in a geologic formation as pressurized potential energy; and batteries use electrical energy to drive chemical reactions and then store that energy as chemical potential energy. As no energy conversion process occurs without inefficiencies or losses, any energy storage system will discharge a lesser amount of energy than used to charge the device. If deployed properly, energy storage can help enable a smarter, stronger, cleaner and more reliable grid.

Xcel Energy has long been a leader in deploying energy storage. We have operated pumped hydro energy storage on our system for decades and have adapted its operation to meet our evolving system. Today, we are implementing pilots and other programs exploring new storage technologies that will play a role in our energy future.

A. Cabin Creek Pumped Storage

Historically, pumped storage hydro has been the dominant source of energy storage – even today, nearly 92 percent of operational storage in the US is pumped storage. Our largest energy storage asset is the 324 MW Cabin Creek pumped hydroelectric storage facility in Colorado. The Cabin Creek facility was built in 1967. Like all pumped storage facilities, it has an upper and a lower reservoir. When economic, we pump water from the lower to the upper reservoir. When the system has additional energy needs, we allow the water to "spill" out of the upper reservoir to the lower through a hydro turbine to generate electricity. Originally, the facility was used to transfer excess energy from off-peak hours to on-peak hours, but today it is also used for renewable energy integration. We spill water to meet customer demand when the wind stops blowing and pump water to the upper reservoir during times when the wind energy generated on our system exceeds customer demands.

B. Luverne MinnWind Storage Project

The Luverne wind-to-battery project in Minnesota was one of the first battery storage pilot projects the Company pursued and the first U.S.-based pairing of wind energy and a storage battery. The pilot was intended to test the various ways batteries could be used to provide wind integration and regulation services supporting the energy grid. The 1 MW, 7 MWh sodium sulfur battery paired with an 11 MW wind project has been in-service since 2009, and was recently updated by the manufacturer with new grounding technology and cells, extending the life of the battery and allowing us to test new battery applications. It was funded in part by a $1 million grant from Minnesota's Renewable Development Fund.[1]

C. SolarTAC

We are the original founding member, host utility and a development partner at the Solar Technology Acceleration Center (SolarTAC), an outdoor solar testing facility located in Aurora, Colorado.[2] Together, the solar industry and utilities work at SolarTAC to test, validate and demonstrate advanced solar technologies under actual field conditions. We worked with our SolarTAC partners to test two different battery storage projects.

- A community energy storage project at SolarTAC is testing a more cost-effective way to improve the integration of solar power in areas with high solar production. Working with the Electric Power Research Institute (EPRI), we are testing a 25-kilowatt battery integrated with four small photovoltaic installations that simulate a neighborhood with multiple rooftop solar power systems.
- Through our Solar2Battery project, we installed a 1.5 MW battery to evaluate how energy storage can help in operating the electricity grid with energy from large-scale solar facilities.

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1 Xcel Energy Wind-to-Battery Project: https://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/wind-to-battery%20fact%20sheet.pdf
2 Solar Technology Acceleration Center: http://www.solartac.org/

These projects have increased our knowledge of how batteries respond to intermittent solar generation, how battery chemistries perform over time, and how energy storage systems can create value for our system.

D. Innovative Clean Technologies Program

The Colorado Public Utilities Commission has approved an Innovative Clean Technologies (ICT) program to test emerging technologies that are designed to lower carbon emissions associated with electricity service. We currently have two battery storage demonstration projects operating under the ICT program:

- Stapleton Community Energy Storage Project: As demand for solar energy at our customers' homes and businesses increases, we are examining how battery storage can help integrate higher concentrations of customer solar energy on our system. Through a project in Denver's Stapleton neighborhood, Xcel Energy installed six customer batteries and six larger grid batteries to test rooftop solar integration and grid support capabilities.[3]
- Panasonic Battery Demonstration Project: Through a public-private partnership, Xcel Energy, Panasonic and Denver International Airport are collaborating to test a battery storage system that can both serve as a microgrid to provide backup power to Panasonic's Denver headquarters and support Xcel Energy's grid at other times. As part of the project, Xcel Energy owns a 1.3 MW solar carport installation and a 1 MW/2MWh lithium ion battery. Panasonic also owns a 0.20 MW solar array located atop its building, which is also tied into the system.[4]

E. Fort McCoy Solar plus Battery Microgrid Partnership Project

We are partnering with Fort McCoy, a U.S. Army installation in Wisconsin, to develop a solar-plus-storage microgrid demonstration project to provide a secure source of power to certain critical facilities on the Army Base. The project will combine onsite solar photovoltaic generation with energy storage to provide additional resilience to support identified facilities through a microgrid in an extended outage, likely in combination with existing backup generation.

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[3] Community Storage Project in Stapleton Neighborhood: https://www.xcelenergy.com/energy_portfolio/innovation/stapleton

[4] Panasonic Battery Demonstration Project: https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-Panasonic-Fact-Sheet.pdf

Through this project, the Company will gain a solar resource to supply energy to its customers, as well as experience with operating and maintaining a solar-plus-battery microgrid and optimizing the use of these resources. We will also gain experience valuable to understanding the performance of these systems, applicability and implementation of new MISO rules for battery storage participating in MISO markets, as well as knowledge and insight that will enhance our ability to understand, plan for and accommodate future battery storage applications. We anticipate this project will be operational in 2021.

These pilot projects have provided operational experience for future, widespread deployment of batteries on our system. From these projects, we have gained detailed information on the value, costs and benefits of battery installations. The projects demonstrate the need for better interoperability between the devices and systems. They will inform future system architecture, including cybersecurity and interconnection issues associated with battery operation. In addition, we currently have nearly 300 residential batteries installed across our states and are working with customers and the storage industry to provide battery interconnection guidelines and support. The legislation passed in Minnesota in 2019 also allows for cost recovery of energy storage system pilot projects.

F. Colorado Energy Plan

The Colorado Energy Plan (CEP) is the next step in our efforts to transform our energy system for our Colorado affiliate. It includes the retirement of two existing coal units and the construction of 1,100 MWs of new wind and 700 MWs of new solar. As part of the all-source bids associated with the CEP, we received 133 total energy storage bids from 97 separate projects. Taking advantage of the tax credit incentives, several of the project developers were able to present us with competitive pricing for batteries paired with solar. From these bids, we selected two separate battery-plus-solar projects totaling over 600 MWs of universal scale solar paired with 275 MWs of battery storage, which was then the largest utility-proposed acquisitions of battery storage in the U.S. The Colorado Public Utilities Commission approved CEP in August 2018, and with this approval we are moving forward to implementation.

III. ENERGY STORAGE VALUES

Energy storage can be deployed in all parts of the energy grid, and can help to enable a smarter, stronger, cleaner, and more reliable energy grid for our customers. There are multiple opportunities for energy storage to add value to our system. We focus here on four key areas: renewable integration, grid support, deferred investment, and power quality.

A. Renewable Energy Integration

As Xcel Energy continues to add significant amounts of renewable energy generation to our system, energy storage can support integrating those renewables into the energy grid. Renewable energy is available when the wind blows or the sun shines, and customer energy demand is often not synchronized with its availability. Storage can help shift renewable energy to time periods when it is needed, reducing the need for investment in peaking plants and support facilities. This is especially true for short-term deviations – a few minutes to a few hours – between customer demand and renewable generation.

B. Grid Support

As the owners and operators of the grid, utilities are first and foremost responsible for the safety, reliability, and optimal operation of our system for our customers. A reliable electric system requires attention to the physics of electricity transmission and distribution. It is not enough to match generation and power supply; we also must make sure that the power can be delivered to customers. Energy storage can help with grid reliability and resilience by providing:

- voltage support at critical places on the electric system where low voltage prevents the transmission of power;
- ancillary services such as:
    - frequency regulation – ensuring that the appropriate frequency of the alternating current on the system is maintained
    - spinning reserves – available resources to increase power output to meet fast changes in demand
    - operating reserves – resources to make up the difference between production and demand when production is low
- energy arbitrage, purchasing and storing electricity during off-peak times, and then utilizing that stored power during periods when electricity prices are the highest;
- readily available reserves, reducing the need for additional investments in "quick start" generation and transmission assets that maintain the system in the event of a disruption; and

- Black start capability, or the ability to restart the entire electric system in the event the whole system goes down.

Utilities are well-positioned to maximize the value of these storage capabilities to ensure system planning and visibility with the primary objective of enhancing reliability and optimizing performance in a cost-effective manner. We can facilitate the deployment of energy storage on our system when and where it is most needed.

C. Deferred Investment

Storage has the potential to take the place of traditional grid investments across our system, including investments in peaking generation, transmission and distribution upgrades, and reliability investments to maintain grid support. Its ability to do so depends on whether the proposed storage resource is (1) capable of providing the same benefits as the asset it replaces; (2) cheaper than the more traditional alternative; and (3) has some level of visibility and control by the grid operator. As storage technologies continue to improve and prices come down, there are greater opportunities for storage to take the place of existing technologies, especially in areas where the unique circumstances of the system make traditional technologies more expensive.

We are actively exploring additional deferral opportunities for our system where storage may provide a solution. This requires new tools and processes to analyze the appropriate location and size of the potential storage solution, as well as a cost-benefit analysis of those solutions as compared to traditional grid investments. Properly positioned storage can defer or reduce the need for incremental transmission and distribution investments, while poorly-sited storage may require additional investments in new capacity or distribution upgrades.

D. Power quality

Some of our customers seek power quality above and beyond what is provided by our standard electric service. Batteries can improve power quality by helping avoid the momentary outages that interfere with the operation of sensitive electronic equipment. Projects like our Panasonic pilot have demonstrated the value of customer-utility partnerships in addressing these issues by placing a utility-owned battery close to, or at, a customer site to provide premium power quality service, while also allowing the utility to leverage the battery for grid services.

We are optimistic about these and other benefits of grid-scale storage. Key to capturing the full spectrum of these benefits 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.

IV. CHALLENGES OF CURRENT ENERGY STORAGE TECHNOLOGY

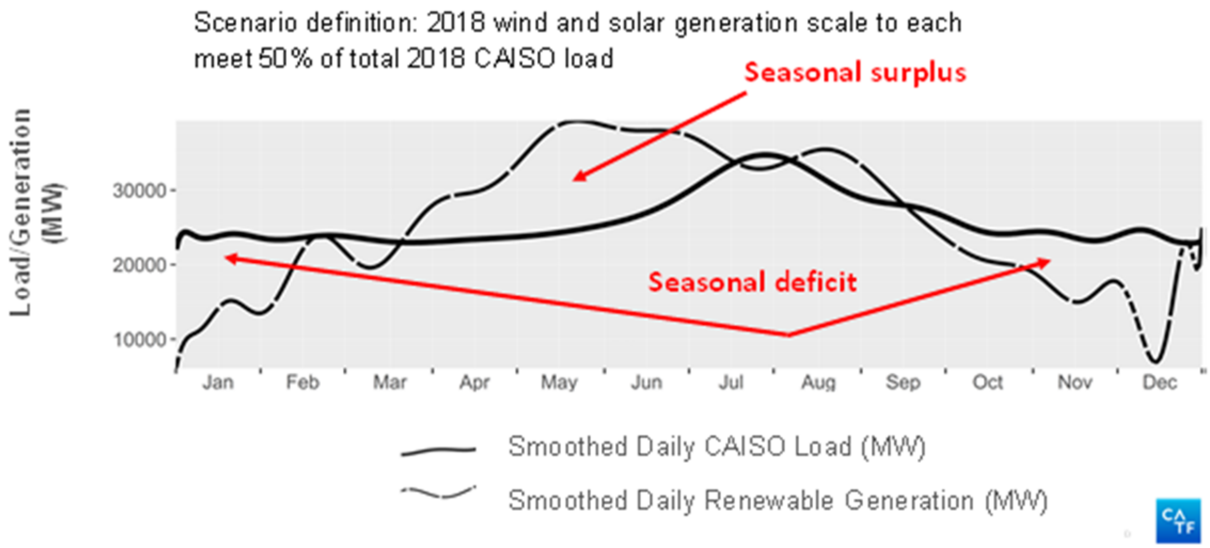
Energy storage offers opportunities to enhance our operations, help us integrate renewable energy, and play an important role in achieving our clean energy vision. At the same time, storage is not a silver bullet that would solve all electricity system challenges. While we see storage as a growing part of our energy system, it must be part of a diverse clean energy portfolio. Storage has inherent limitations that policy makers and utilities must keep in mind as we invest in the energy system of the future.

A. Seasonal Renewable Variation

Xcel Energy has been a long-time leader in renewable energy, and has done nation-leading work to integrate growing levels of renewables across our system. Wind and solar have been a key part of our strategy for more than a decade, and we plan to continue to add renewable energy as long as we can do so cost effectively and reliably.

As discussed above, storage has growing value to help integrate renewable energy on the electric system. Seasonal variation in renewable generation is the primary reason that the cost of renewable energy grows so substantially as renewable penetration increases. The Clean Air Task Force (CATF) chart below shows that, during the periods when renewable output is very high, the California energy system would generate substantial additional renewable energy. This additional renewable energy would have to charge a massive amount of storage capacity to ensure that load is served when renewable output is relatively low.

Figure 1: Clean Air Task Force – Smoothed Daily Load and Renewable Energy Generation, Mixed Renewable Scenario



In fact, CATF estimates that 9.6 million MW-hours of energy storage would be required to achieve 80 percent renewables in California—compared to the roughly 150,000 MW-hours of storage in California now. To reach 100 percent renewables, CATF has concluded that California would need 36 million MW-hours of storage. The cost of storage to achieve 100 percent renewable electricity in California would be astronomical – an estimated $3.6 trillion in capital costs to store all the surplus renewable generation, even assuming a 60 percent drop from today's storage costs.

We believe similar challenges would exist on our system. Based on E3's analysis of our carbon reduction scenarios for our Upper Midwest System, excluding new gas resources more than doubles the costs of reducing CO_2 emissions 85% by 2030 and 95% by 2045 compared to reaching the same goal with only renewable energy and storage additions.[5]

We remain committed to providing our customers with a carbon-free electric system, and we will add renewable energy to that system as long as it makes sense. We expect that storage will play an important role in a future clean energy system. However, given the huge challenge of seasonal variation in renewable generation, it is not realistic to expect that storage will make a 100 percent renewable energy system possible. Storage alone cannot provide our customers with the reliable and affordable

[5] Energy and Environmental Economics analysis of Low Carbon Scenarios on Xcel Energy's Upper Midwest System (E3 System Study), Appendix P2.

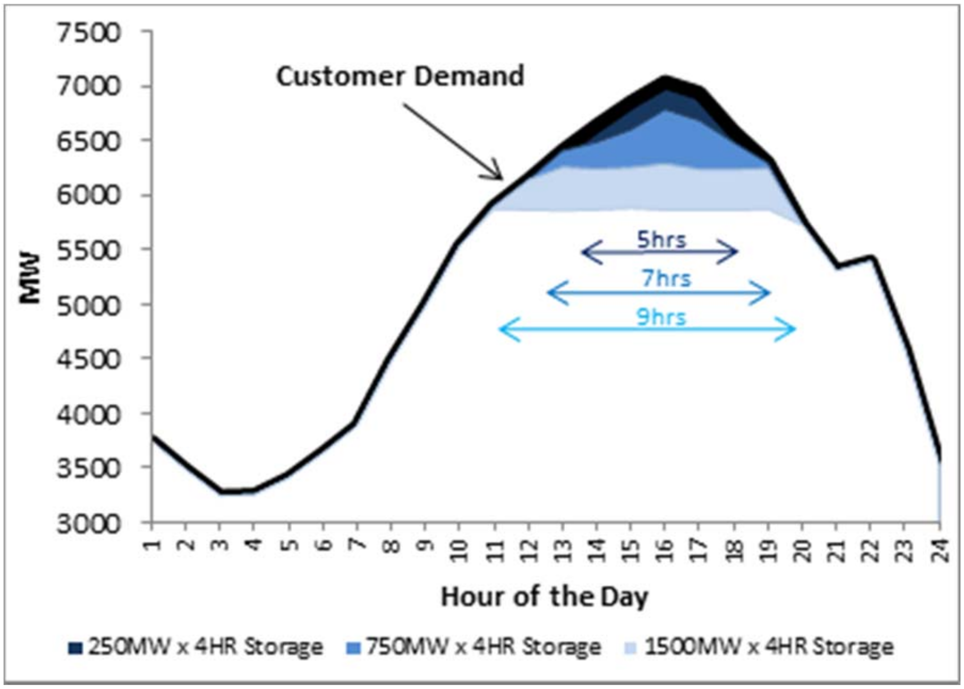
energy that they need. A broader suite of new dispatchable zero carbon technologies will be key to achieving our long-term carbon goals.

B. Declining Marginal Capacity Value

Storage can help meet peak energy demand by shifting some excess renewable energy to periods when it is needed, but this value declines dramatically as more storage is added to the system. As its name implies, a system peak is like the top of a mountain or a pyramid. It represents a short period of time during each day when energy usage is at its highest. Energy storage can shave off and lower the top of the peak, but it also widens it. As a result, larger, more expensive storage systems are required to further reduce the system energy needs.

The following chart illustrates this problem. The black line represents a single illustrative day of energy demand for one of our operating companies. Suppose that a 250 MW battery with four hours of storage capability is added to the system. It will shave off the top of the peak for a five hour period and shift the curve so that it takes advantage of parts of the day where excess renewables may be generated. The result is a lower, wider peak – more like a plateau. The next tranche of peak reductions requires substantially more storage to achieve the same effect – in this example, 750 MW of four hour batteries that are able to discharge over an approximately 7-hour period. The next tranche of demand reduction will require an even more substantial investment in storage i.e. a 1500 MW battery operating for almost 9 hours.

Figure 2: Battery Storage for Peak Demand Reduction



This chart illustrates that more batteries with longer duration are required at each step to reduce the peak. This problem is further compounded during periods of low renewable production, when excess generation may not be available to re-charge batteries to be available for the next peak.[6] At some point, it is not technically or economically feasible to continue to use storage to shift energy from off-peak to on-peak periods.

C. Stacking Storage Values

As referenced above, storage provides multiple values, each of which can enhance the operation and efficiency of the grid. Adding multiple values together – "stacking" – can make the storage resource more valuable as a whole. For example, a storage resource that provides voltage support and renewable integration will be more valuable than a storage resource that provides only one of these benefits. As the cost of storage continues to decline, stacking these benefits together increases the probability that a utility would choose to add a battery or other storage resource to its system.

[6] See E3 System Study, Figure 4-4, Appendix P2.

At the same time, in determining the value of a storage resource, its multiple potential benefits should not be added if one value precludes another. A battery may simultaneously provide voltage support and frequency regulation, but it cannot, for example, simultaneously integrate renewables and provide black start capability. In the latter case, the battery must be available to restart the system, and it may not be available to do so if it has been discharged to integrate renewables. Thus, the value of storage must be determined based on a utilities need for the potential value streams storage provides, and the ability and efficiency of storage to meet those needs.

V. ENERGY STORAGE ANALYSIS IN THE RESOURCE PLAN

We are considering storage opportunities in our resource planning processes in a number of our states. As mentioned above, our Colorado system already has 324 MW of pumped storage and we will be adding another 275 MW of storage embedded in solar by 2022. In this Resource Plan analysis we included a four hour generic battery storage resource in the modeling as an option to meet energy and capacity needs. The characteristics and cost assumptions for the storage resource can be found in the Strategist Assumptions in Appendix F2. In our modeling, the generic storage was allowed to compete with other resources to meet energy and capacity needs per the statutory requirement. If we have future needs, our model will select storage when it is a cost-effective resource. We continue to consider new tools and processes to analyze the appropriate location and size of storage solutions including the evaluation of potential values storage assets might provide to the system.

The Strategist model includes a spinning reserve requirement of 137 MW based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO. Strategist does not account for other ancillary services and the associated value storage or any other resource may provide. Costs related to integrating renewables are included in Strategist by adding an integration cost to wind and solar.

Included as Appendix P2 is E3's Low Carbon Scenario analysis which used E3's RESOLVE model to evaluate deep decarbonization scenarios on our Upper Midwest System. The RESOLVE model utilizes a chronological hourly dispatch in contrast to the load duration curve methodology utilized by Strategist. In addition, RESOLVE includes the following operating reserve requirements which must be met by each resource portfolio:

1. Load following reserves requirements are set at 3% of load;
2. Frequency regulation reserve requirements are 27 MW; and
3. Spin reserve requirements are set at 1% of load.

The conclusions of E3's Low Carbon Scenario analysis generally support our preferred plan as a least cost way to achieve deep reductions in CO_2 emissions. Regarding storage, E3's analysis found the storage additions were not cost-effective on our system in the near-term, but were selected later in the planning period.

We will continue to evaluate storage in future resource plans, and will acquire new modeling tools that are better able to analyze high renewable scenarios. 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) and therefore it is primarily those needs will help drive storage additions in the future. Given our excess capacity position thru the mid-2020s, storage is unlikely to be cost-effective in the near term. However, the Company will continue to explore near term storage opportunities that could provide value to our system. In addition, storage resource will be considered to help meet firm, dispatchable capacity needs that have been identified in our Preferred Plan in the 2030s.